Review of Carbon Capture Projects Funded By Alberta Innovates and Related Entities with Recommendations

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1. Abstract

This paper shares the lessons learned from a portfolio of Alberta Innovates, InnoTech Alberta, C-FER and ERA funded projects related to carbon capture. This paper serves to summarize the body of knowledge developed and supported by these organizations, and to recommend ways to help enable widespread use of CCUS both in Alberta and around the world. It is primarily focused on technology and knowledge development, identifying technology gaps, providing insights and recommends initiatives to develop carbon capture technologies for widespread deployment to support emissions reductions targets.

2. Introduction

2.1. Context

Significant global efforts are being undertaken to reduce the emissions of greenhouse gases to mitigate the impacts of climate change, and carbon capture, utilization and storage (CCUS) are important methods of achieving greenhouse gas reductions. Recent publications such as the International Energy Agency's Net Zero Emissions by 2050 document show the forecasted role of CCUS in contributing towards reducing emissions to meet targets (IEA, 2021a). In addition, Canada's Federal government has developed a Climate Plan (Government of Canada, 2021a) and its 2021 budget (Government of Canada, 2021b) propose to build a pathway to achieve net zero emissions by 2050. In this budget the Federal government has identified $17.6 billion in investments, including investments in CCUS. The Government of Alberta has also provided guidance with its Natural Gas Vision and Strategy (Government of Alberta, 2020) which outlines the need for low-carbon hydrogen markets to develop which will rely on CCUS to ensure appropriate management of the associated CO_2 emissions. The Government of Alberta has already developed and operates a regulatory framework for carbon capture for enhanced oil recovery projects and is actively developing a tenure and regulatory framework for carbon sequestration projects. A Federal/Alberta Steering Committee on CCUS is actively working on approaches to ensure widespread adoption of CCUS in the province. In the US, significant funding is being put towards improving carbon capture and storage solutions by the Department of Energy (US DOE, 2021b) and National Energy Technology Laboratories (NETL, 2021b).

In addition to governmental initiatives, industry is taking action towards reducing its greenhouse gas emissions footprint. The Oil Sands Pathways to Net Zero consortium comprising five oilsands producers, representing 90 per cent of the total bitumen production from Alberta, have committed to net zero emissions by 2050. Carbon capture will be a key component of the strategy to achieve this goal. Several industry projects have been developed in Alberta and are currently operating, including the Shell QUEST project, and the Alberta Carbon Trunk Line which transports CO_2 from Nutrien's Redwater fertilizer plant and the North West Sturgeon Refinery to the Enhance Energy production fields for enhanced oil recovery (EOR) operations.

2.2. Purpose of this Paper

This paper has been published as part of a series of papers on work completed on various aspects of carbon capture with recommendations regarding how to advance carbon capture in the future. This paper shares the lessons learned from a portfolio of Alberta Innovates, InnoTech Alberta, C-FER and ERA funded projects related specifically to carbon capture completed over the past two decades. These organizations work very closely to ensure the most efficient development and deployment of promising solutions occurs within Alberta. This paper serves to summarize the body of knowledge developed and supported by these organizations, and to identify the remaining gaps that need to be addressed with recommendations regarding how to help enable widespread use of carbon capture both in Alberta and around the world. It also provides information on promising carbon capture technologies, information on the characteristics of flue gases, the cost of carbon capture and carbon capture projects in development. This paper is not intended to be a policy position paper, but it may be used to inform policy decisions as required. It is primarily focused on technology and knowledge development, identifying technology gaps, insights and priority focus areas for further investment to de-risk CCUS technologies for widespread deployment to support emissions reductions targets.

2.3. Alberta Funding Support for Carbon Capture

Alberta Innovates is Alberta's clean energy innovation engine and has annual funding available to enable the scale-up of a broad array of clean energy technologies. Alberta Innovates typically supports innovative technologies between proof of concept and field piloting (TRL 3-7), and awards funding on the basis of technological innovation, environmental improvement potential, social and economic impacts and potential for deployment in Alberta.

InnoTech Alberta (InnoTech) is a subsidiary of Alberta Innovates and is Alberta's premier applied research organization and maintains facilities in Alberta that are accessible to industry for technology demonstration and scale up between bench-scale proof of concept through to pre-commercial scale piloting. InnoTech operates the Alberta Carbon Conversion Technology Centre (ACCTC) as well as research facilities in Calgary, Edmonton and other locations in Alberta. The ACCTC is a world-class pilot testing facility for carbon capture and utilization technologies to be tested with post-combustion exhaust from ENMAX and Capital Power's Shepard Energy Centre power plant. This facility hosted the NRG COSIA Carbon XPRIZE competition which resulted in several commercial successes.

C-FER Technologies is also a subsidiary of Alberta Innovates and is a leading engineering analysis and large-scale testing service provider in Alberta. C-FER is focused on leading edge analysis and testing for new and 'first-of-a-kind' technologies, processes and procedures to solve industry challenges. C-FER has particular experience in pipelines and conducts testing, risk analyses, technical analysis and contributes to the development of standards for pipelines and other industrial infrastructure. C-FER works with InnoTech and Alberta Innovates on projects and initiatives to help advance Alberta's position as an innovator in a range of industries.

Emissions Reduction Alberta (ERA) is an independent organization that receives it's funding through the *Technology Innovation and Emissions Reduction (TIER) Regulation* and supports innovative greenhouse gas reduction projects through targeted calls for proposals, generally focused on higher TRL technologies between pilot scale and commercial demonstration. ERA emphasizes direct GHG impact and attracting investment to Alberta. Where appropriate, ERA works in partnership with Alberta Innovates and InnoTech.

Alberta Innovates and its subsidiaries InnoTech Alberta (InnoTech) and C-FER Technologies (C-FER) as well as ERA each have decades of experience in carbon storage, enhanced oil recovery, reservoir characterization, carbon capture, carbon utilization and supporting technology development in these fields. These organizations have developed a world-class portfolio of carbon capture, utilization and storage projects. This document serves as a summary and compilation of the breadth and depth of experience gained within Alberta through carbon capture projects funded by these organizations.

2.4. CCUS Overview, Economic and Regulatory Context

In addition to meeting climate objectives as described above, CCUS may also be adopted for the following direct financial reasons:

1) CCUS may be a lower net cost way to meet regulatory obligations to physically reduce emissions compared to other ways to physically reduce GHG emissions which allow an entity to continue to operate, or
2) CCUS may be a lower net cost option to meet carbon tax obligations than either other physical GHG reduction options or monetary costs to buy credits or offsets to comply, or
3) CCUS may also be adopted to generate a profit by selling credits, offsets and the CO_2 commodity for other uses.

These opportunities are described further in the following sections.

In 2012 Alberta Innovates commissioned MK Jaccard and Associates to study the economic benefits of Carbon Capture and Storage (CCS) (Peters, Sharp, Bataille, Groves, & Melton, 2011). They listed six key benefits of CCS and also listed several other possible benefits. The six key benefits are:

- CCS could help Alberta maintain access to U.S. export markets;
- CCS can reduce the costs to industry of complying with climate change policies;
- Enhanced oil recovery would reduce the costs for CCS in the short- to medium-term and increase conventional oil production in the long-term;
- CCS will enable the continued use of coal to generate inexpensive electricity;
- CCS could help to avert social pressures related to the Alberta's oil sands; and
- CCS could increase the size and economic impact of Alberta's knowledge sector.

Jacobs provided the quantitative and technical input parameters MK Jaccard and Associates used to model the economic impacts of CCS in a separate report (Jacobs Consultancy, 2011).

2.5. Regulation Requiring Physical Reductions

Under the proposed Clean Fuel Regulations, entities producing liquid fossil fuels will be required to significantly reduce the emission intensity to produce such fuels (Government of Canada, 2020). Under Federal regulations coal plants must meet an emission intensity of 0.42 t/MWh after running for a period of time (Government of Canada, 2012). Under Federal regulations emission limits are also placed on new natural gas power plants and coal plants converted to burn natural gas (Government of Canada, 2018). In Alberta under the TIER Regulation the baseline emission intensity is 0.37 t/MWh for all power plants and remains fixed and 40 per cent per cent of yearly GHG emission reduction requirements must come from physical reductions or through the purchase of fund credits (Government of Alberta, 2019). Therefore, in general these regulations provide little opportunity to buy credits and require entities to physically reduce GHG emissions. These regulations along with proposed increases in the carbon tax and environment, social and corporate governance (ESG) pressures will spur the development of CCUS in Canada.

2.6. Value of CO_2 as a Commodity

Captured CO_2 can be utilized as a feedstock for other processes to make a product or to make a lower carbon fuel. Captured CO_2 may also generate concomitant commodities of value. For instance, molten carbonate fuel cells produce power, water and may also produce hydrogen in addition to capturing CO_2. Entities can potentially derive additional value for CO_2 by using it to enhance oil recovery.

In 2013 Bill Gunter and Herb Longworth completed a report for Alberta Innovates describing how to overcome the barriers to widespread adoption of CCS to support enhanced oil recovery (EOR). The report identified seven major issues/barriers to EOR addition. They were high cost of CO_2, major oilfield unitization effectiveness, determining how well-suited reservoirs are for CO_2-EOR, competition with other oilfield efficiency improvement technologies, addition of new unconventional hydrocarbon reservoirs, decreasing the demand for tertiary recovery, and uncertainty on the drivers for converting a CO_2-EOR project to a CCS project (Gunter & Longworth, 2013).

Jacobs completed a report for Alberta Innovates studying the impacts of CCS. The report examined potential CO_2 supply and EOR demand for CO_2 and concluded that there is potentially much more CO_2 supply than there is available EOR pools. The report predicted that with an oversupply of CO_2, the CO_2 price for EOR projects would be reduced over time (Jacobs Consultancy, 2011). However, the report also indicates that the steady and consistent supply of low-cost CO_2 could stimulate the EOR market in Alberta, thereby incentivizing EOR activity (Jacobs Consultancy, 2011).

The Jacobs report was written in advance of the Federal carbon tax and carbon pricing program and shows an emphasis on increasing oil production. The conversation has recently shifted from how to produce more oil to how to sequester more CO_2. Regulations are being developed in Alberta to address carbon sequestration in response to this market driver. The federal carbon tax program is described further in the next section.

2.7. Value of CO_2 to Generate Valuable Credits

CCS can also be used to generate credits which may have economic value. If the adoption of CCS causes the entity's emission intensity to fall below the baseline emission intensity established for carbon tax purposes, then under the TIER Regulations the entity may generate emission performance credits (EPCs). These credits may be sold to other parties so they can comply with carbon taxes. Under the proposed *Clean Fuel Regulations* there is the ability to buy and sell unique compliance credits (not EPC) to meet *Clean Fuel Regulations* obligations.

The Greenhouse Gas Pollution Pricing Act determines how carbon taxes will be established in Canada (Government of Canada, 2021c). Under the Act carbon taxes are paid based on the GHG emissions produced based on an output-based pricing system (Government of Canada, 2021d). Carbon taxes are also paid on the GHG emissions associated with the consumption of fuels (Government of Canada, 2021e). The Federal Government also announced that the carbon tax would increase from $50/t in 2022 by $15/t per year to $170/t in 2030 (Tasker, 2020). However, provinces may be able to get approval from the Federal Government to establish their own carbon tax pricing systems. Alberta has established the TIER Regulations which defines how carbon taxes will be levied in the province.

The TIER Regulations define baselines for various processes or types of industrial processes. Under TIER Regulations, reducing emissions, offsets, fund credits and EPC can be used to meet GHG emission obligations. However, EPCs can only be used to meet 60 per cent of yearly requirements and the rest must come from physical GHG reductions or through the purchase of fund credits (Government of Alberta, 2019). The value of these EPC is largely independent of the fund price or carbon tax price since their value is dependent upon supply and demand dynamics for EPCs. Fund credit prices set a ceiling price on the costs to comply.

3. Carbon Capture

3.1. Opportunities to enable Carbon Capture on Existing GHG Emission Processes

3.1.1. Existing CO_2 Emissions in Alberta in 2019

The following Table 1 shows the classes of industrial processes in Alberta with the largest GHG emissions in 2019. The GHG emissions reported in this table account for 90 per cent of the GHG emissions in 2019. The first three columns show the total GHG emissions by class, the number of facilities in the class and the average yearly GHG emissions for a facility in each class. It is assumed that carbon capture may be more viable on large point sources of CO_2 due to economies of scale. However, many of these facilities emit less than 100,000 t/yr. The right-hand portion of Table 1 shows GHG emissions just for those facilities which emit more than 100,000t/yr. The classes of emission above the solid line are likely those classes of facilities where carbon capture is more likely to lead to significant GHG emissions reductions.

Table 1: GHG Emission in Alberta for 2019 (Government of Canada, 2021f)

	As Reported			>100,000 t/yr		
	Total (t/yr)	#	Ave (t/yr)	Total (t/yr)	#	Ave (t/yr)
In-situ oil sands extraction	38,111,258	27	1,411,528	38,100,751	25	1,524,030
Fossil-fuel electric power generation	35,977,081	38	946,765	35,681,198	26	1,372,354
Mined oil sands extraction	35,623,646	7	5,089,092	35,623,646	7	5,089,092
Oil and gas extraction (except oil sands)	17,361,110	450	38,580	6,430,996	31	207,451
Petrochemical manufacturing	5,368,280	5	1,073,656	5,368,280	5	1,073,656
Pipeline transportation of natural gas	5,086,566	5	1,017,313	5,060,505	4	1,265,126
Petroleum refineries	4,568,617	4	1,142,154	4,568,617	4	1,142,154
Chemical fertilizer (except potash) manu	2,533,162	5	506,632	2,511,426	4	627,856
Industrial gas manufacturing	2,356,463	3	785,488	2,345,969	2	1,172,984
Cement manufacturing	1,688,579	2	844,290	1,688,579	2	844,290
Chemical pulp mills	672,834	4	168,209	672,834	4	168,209
Other basic organic chemical manufactur	706,531	4	176,633	588,790	2	294,395
Non-ferrous metal (except aluminum) sm	319,972	1	319,972	319,972	1	319,972
Waste treatment and disposal	1,153,566	27	42,725	290,522	2	145,261
Bituminous coal mining	331,244	3	110,415	243,300	2	121,650
All other basic inorganic chemical manuf	178,085	2	89,043	159,000	1	159,000
Lime manufacturing	150,554	1	150,554	150,554	1	150,554
Natural gas distribution	200,698	3	66,899	148,199	1	148,199
Newsprint mills	145,730	1	145,730	145,730	1	145,730
Other petroleum and coal product manu	123,634	1	123,634	123,634	1	123,634
All other non-metallic mineral mining an	18,906	1	18,906	-	-	-
Iron and steel mills and ferro-alloy manu	89,856	1	89,856	-	-	-
Mechanical pulp mills	113,564	2	56,782	-	-	-
Subbituminous coal mining	243,613	5	48,723	-	-	-

However, a significant portion of these emission will likely not be captured. There may be other lower cost ways to avoid these emissions. Some classes of emissions may no longer continue to exist such as those related to coal power production. Also, industrial processes may change allowing for reduced emissions intensity. For example, Suncor is replacing its coke-fired boiler with an 800 MW cogen

(Suncor, 2021). In many facilities there may be a significant number of point sources of CO_2 which may be too small to capture economically. In addition, many of the point sources may be in confined spaces making them very difficult to access to duct the flue gas to a carbon capture system. There may also not be sufficient space on-site to construct a carbon capture project.

Most of the GHG emissions listed in Table 1 will, in the near future, be generated from the combustion of natural gas as a fuel. The majority of GHGs from existing sources will likely be from once through steam generators (OTSG), gas turbines providing power to the grid, cogens supplying behind-the-fence steam and power, converted and repowered coal plants, emissions from various heaters and boilers, from steam methane reformers (SMR), and cement plants. Therefore, the majority of carbon capture opportunities will likely be confined to GHG emissions from the combustion of natural gas.

Most of the emissions from fossil-fuel electric power generation, in-situ oil extraction, mined oil sands extraction and pipeline transportation of natural gas shown in Table 1 above will be produced by gas turbines or OTSGs. The concentration of CO_2 from these sources will be about 4 per cent making them more expensive to apply carbon capture than higher concentration sources of CO_2 (Ordorica-Garcia, Wong, & Faltinson, 2009) (Suncor, 2012). For a given pressure, as the concentration of CO_2 decreases, the volumetric flow rate of flue gas required to capture a tonne of CO_2 increases. Therefore, as the concentration decreases, the size of the equipment needed to capture a tonne of CO_2 increases proportionally driving up costs to capture CO_2. Additional discussion on the impact of CO_2 partial pressure on capture cost can be found in Section 3.6.3.

3.1.2. Forecasts of Carbon Capture

Alberta Innovates commissioned a report completed in 2009 which forecasted the supply of CO_2 from Fort McMurray and produced a set of CO_2 capture cost supply curves. The report provided a number of CO_2 source characteristics (Table 2 and Table 3).

Table 2: CO_2 source stream characteristics from Steam Methane Reformers (Ordorica-Garcia, Wong, & Faltinson, 2009)

Exhaust Source	CO_2 (%)	N_2 (%)	O_2 (%)	S (ppm)	Temp (°C)	Pressure (kPa)
Gas Turbine	3.5%	81.3%	15.2%		130	120
Cracking or Reformer Furnace	9.2%	87.1%	3.7%		200	Atmospheric
Main Stack	13%	83.4%	3.6%	300		

Table 3: CO_2 source stream characteristics (Ordorica-Garcia, Wong, & Faltinson, 2009)

Source	CO_2 (%)	CH_4 (%)	C_2H_6 (%)	N_2 (%)	H (%)	CO (%)
SMR	18.6	0.9	0.1	0.2	78	2.1

The authors suggest that CO_2 capture costs will decrease as the concentration of CO_2 increases (Ordorica-Garcia, Wong, & Faltinson, 2009). This suggests that large, high concentration point sources of CO_2 may represent the most economical capture opportunities to enable first.

In 2014 Pembina Institute completed a report for Alberta Innovates forecasting GHG emissions in the oil sands out to 2050 (Kilpatrick, Goehner, Angen, McCulloch, & Kenyon, 2014). The report estimated GHG emission sources with various assumed penetration rates of carbon capture. The report also estimated various carbon capture costs based on learning curve projections. The report provided some information on the projected impact of carbon capture on the cost of oil and overall reductions in GHG emissions.

3.1.3. Greenhouse Gas Reduction Roadmap

In 2012 the Climate Change and Emissions Management Corporation (CCEMC) and Alberta Innovates funded a study entitled "A Greenhouse Gas Reduction Roadmap for Oil Sands". The report was completed by Suncor and Jacobs. "The primary objective of the Study was to identify, assess, and quantify energy efficiency and GHG reduction opportunities for commercial oil sands operations and determine their potential impact on the GHG intensity of fuels refined from oil sands derived bitumen." (Suncor, 2012). The following describes the results for various facility types.

In Situ Facilities

The report indicated that carbon capture costs using current technologies are estimated to be between $75 and $200 per tonne of CO_2 avoided, depending on the technology type and emissions stream used. In addition to high cost, the report identifies several other barriers to implementation of carbon capture, which include:

- Space constraints (for retrofit facilities);
- Suitable geological sites for CO_2 storage;
- Pipeline access, and costs of the pipeline to transport CO_2 to storage sites; and
- The significant utility needs (steam and/or electricity) for carbon capture that offsets much of the gain from capturing CO_2.

The report states that "OTSGs are generally more suited to CO_2 capture than cogeneration facilities because the CO_2 is present at higher flue gas concentrations (typically 8 to 10 per cent vas opposed to 4 to 8 per cent in a cogeneration facility, depending on the configuration)" (Suncor, 2012). The report concludes that for In Situ carbon capture applications "CCS is not economically justified at current CO_2 costs" (Suncor, 2012). At the time this report was written, the price for CO_2 was $15/tonne through the *Alberta Specified Gas Emitter Regulation*, the pre-cursor to the TIER Regulations.

Mining and Extraction

This report reiterates that stand-alone boilers are generally more suited to CO_2 capture than cogeneration facilities for mining and extraction as well, because the CO_2 is present at higher flue gas concentrations (typically 8- to 10 per cent as opposed to 4 to 8 per cent in a cogeneration facility, depending on the configuration). The report concludes that "CCS for GHG reduction is not suitable for Mining and Extraction facilities that use low level heat from upgrading or on-site power generation. Finally, CCS is not economically viable for Mining and Extraction facilities at current prices for CO_2" (Suncor, 2012).

Upgrading

This same report analyzed the suitability of carbon capture at upgrading facilities, concluding that brownfield retrofits are very challenging and expensive due to the limited space available for the unit as well as associated piping. This restriction reduces available capture opportunities to 30 to 50 per cent of emissions sources representing a 20 to –40 per cent reduction in GHG emissions as many of the sources are dispersed throughout the site. The capture facilities will also increase power demand, which will result in increased emissions. The study concluded that carbon capture is not economically viable for bitumen upgrading facilities at the carbon prices available during the writing of the report (i.e. $15/tonne) (Suncor, 2012). The price of carbon in Alberta and Canada has since increased.

The report concludes that current carbon capture technologies are too expensive to implement at oil sands facilities at the carbon prices available at the time of report writing (Suncor, 2012). Two clear gaps regarding carbon capture were identified in this report. First, carbon capture adoption is constrained by space limitations and carbon capture technologies which can address this gap should be investigated. Second, the cost of carbon capture needs to be reduced to be economically viable.

3.2. New Future Opportunities to use Carbon Capture

As mentioned above many of the point sources of GHG emissions may be too small or may be too hard to access to make carbon capture viable. For this reason, the emissions for these point sources can be avoided by supplying a low carbon fuel to their underlying processes. Hydrogen has been identified as such a fuel. Unlike hydrogen used as a petrochemical or fuel cell feedstock it need not be very pure to be used as a fuel for combustion. By relaxing the purity requirement, other lower cost configurations to produce a low carbon fuel can be considered. SMRs have traditionally been used to produce high purity hydrogen for use as a feedstock due their cost and efficiency advantages. However, only about 60 per cent of the CO_2 available is at high concentration and pressure in the process stream. The remaining 40 per cent is emitted from the furnace flue at a relatively low concentration making it expensive to capture.

However, because of the inherent difficulty of capturing the flue gas emissions, auto thermal reformers (ATRs) have been identified as more attractive options since most of the CO_2 emissions can be recovered at higher concentrations in the process stream. ATRs can also be built at very large scale. Gasification and in-situ coal or oil gasification have also been identified as ways to produce low carbon fuels, syngas and hydrogen. Hydrogen can also be used as a transportation fuel, as a fuel for power generation and can be blended into natural gas.

3.3. Description of Alberta Innovates Support for Carbon Capture

Alberta Innovates has a clean resources focus which supports Alberta energy and resources. Alberta Innovates develops and invests in applied research and innovation programs to sustain, grow and diversify the energy and resource industries, develop clean technology, reduce greenhouse gas emissions, and protect Alberta’s environment (Alberta Innovates, 2021). For this reason, Alberta Innovates has been involved in many efforts to advance carbon capture.

Alberta Innovates has commissioned and written many reports and studies of carbon capture technologies and opportunities. Alberta Innovates has also directly funded the development of specific carbon capture technologies. It has also been involved in processes to provide funding to develop carbon capture technologies. Alberta Innovates staff have been heavily involved in evaluating funding proposals and managing the process to release funding to carbon capture projects for Emission Reduction Alberta (ERA) (formerly Climate Change and Emission Management Corporation (CCEMC)), TIER funding, Climate Change Innovation and Technology Framework (CCITF) funding, Clean Resource base funding, etc. Alberta Innovates staff have also been involved in supporting carbon capture through partnerships with Sustainable Development Technology Canada (SDTC), National Research Council (NRC), Natural Resources Canada (NRCan) and the Clean Resource Innovation Network (CRIN).

Alberta Innovates also funded the Canadian Clean Power Coalition (CCPC) for more than a decade and provided staff to participate on its technical and management committees. The CCPC spent more than $40 million studying ways to reduce emissions from fossil fuel plants and completed many studies on carbon capture.

Many of the reports and studies referred to below were created due to funding and technical support from Alberta Innovates listed in the various initiatives described above.

3.4. Major Industrial CO_2 Sources and Commercial Technologies

This section describes various commercial applications of carbon capture used to address GHG emissions from specific industrial processes such as hydrogen production, steam generation and power production. In many cases the performance of these forms of carbon capture on a given industrial process are compared to each other to identify advantages and disadvantages and to inform recommendations for further development.

3.4.1. Hydrogen Production

Shell Quest Project

In August 2015 Shell commenced operation of the Shell Quest project which captures about 1 million tonnes of CO_2 per year from three SMRs. Alberta Innovates provided $6.6 million for early-stage planning work for the project. The project had a capital cost of about $920 million and is designed to capture about 80 per cent of the CO_2 in the high-pressure process stream containing the hydrogen. Shell modified one of its amine capture systems for use in the project. A final report was released in 2019 providing information on issues faced, technology selection, costing, design considerations, etc. (IEAGHG, 2019). Further information on the project is available on the Government of Alberta website (Shell Canada, 2021).

3.4.2. Steam Generation

HTC Purenergy was awarded $240,000 by the CCEMC to complete a FEED study to capture 1,000 t/d of CO_2 from a Devon OTSG (ERA, 2020a). HTC Purenergy estimated the CAPEX at $83.1 million CAD, and an average capture cost of under $37/tonne + an OPEX cost of $30/tonne to have a total capture cost of under $70/tonne (HTC Purenergy Inc, 2011). The reported recommended that additional engineering needed to be completed on the inlet exhaust gas cooling process and for heat integration (HTC Purenergy Inc, 2011).

Long Lake Gasification with Carbon Capture

In 2008 Opti Canada received funding from the Alberta Energy Research Institute (AERI) (now Alberta Innovates) to study a Phase 2 expansion of the upgrader to include a new gasification train with carbon capture. A very preliminary capital estimate to store 10,550 t/day of CO_2 was provided in constant 2007 dollars (OPTI Canada, 2008). The study indicated that capture costs, both CAPEX and OPEX, are prohibitive and are too energy intensive. The report indicated that carbon capture implementation will depend on many factors, including (OPTI Canada, 2008):

- Financial incentives provided for deployment;
- Clear legal and regulatory framework;
- Ways to offset the inherent liability in transporting and long-term storage of CO_2;
- Public awareness, perceptions and acceptance; and
- The development of new and better technologies to reduce the cost of capture.

A study of amine (MEA) versus Selexol method for CO_2 capture revealed that the MEA process was able to capture more CO_2, but the Selexol process resulted in a lower transportation CO_2 footprint with overall results being similar (Ordorica-Garcia, Wong, & Faltinson, 2009).

3.4.3. Power Production

Boundary Dam

The Boundary Dam coal-fired power plant has been operating since 2014 with commercial-scale carbon capture, producing 115MW of electricity with up to 90% capture rate for CO_2 (SaskPower, 2021b). The facility was the first power plant to successfully incorporate carbon capture at commercial operations. The Cansolv amine solvent solution was deployed which was at the time unproven commercially (IEAGHG, 2015). The decision and planning to pursue this world-first project used the work completed by the Canadian Clean Power Coalition as a foundation. The Canadian Clean Power Coalition's work was supported by Alberta Innovates and is discussed separately in this document.

3.4.4. Chemical Manufacturing

The Alberta-based Sturgeon Refinery owned by the North West Redwater Partnership uses a Rectisol® acid gas removal process from its syngas production gasifier unit (North West Redwater Partnership, Wolf Carbon Solutions and Enhance Energy, 2019). This technology is licensed from Lurgi in Germany and uses cooled methanol as an absorbent for CO_2. The captured CO_2 is fed into the 242 km long Alberta Carbon Trunk Line for shipping to Enhance Energy's enhanced oil recovery operations.

3.4.5. Summary of Commercial Carbon Capture

Currently, the only commercial capture technologies are amines, solvents such as Selexol, and methanol-based systems such as the Rectisol® process. Other solutions are being tested at varying scales but are still pre-commercial. Consequently, if immediate deployment of carbon capture equipment is needed, these will be the only viable 'off-the-shelf' options. There are incremental improvements that are possible with these technologies and processes, but if step-change improvements in performance, energy requirements, and carbon footprint are needed, new innovations are needed to scale up to market-readiness. Unfortunately, this takes time and significant research, development and deployment efforts. Hybrid solutions may be possible, where these systems are supplemented with additional new tech to improve performance. However, it may be that next generation technologies will eventually surpass and supplant amines.

3.5. Second Generation Carbon Capture Technology Development

Alberta Innovates and InnoTech Alberta (InnoTech) have been advancing the development of many individual carbon capture technologies. They have studied these technologies, funded project R&D, and collaborated on setting up the ACCTC. This modularized facility has several testing bays and has an on-site carbon capture unit that can produce up to six tonnes per day of concentrated CO_2 using amine-based CO_2 capture technologies. It can be used to test novel CO_2 capture solvents, ancillary capture processes and CO_2 conversion processes through either direct-from-flue or pre-concentrated CO_2 streams through the capture unit. Alberta Innovates has also been heavily involved in evaluating funding requests to support carbon capture development. The following describes the results of studies and project reports related to individual carbon capture technologies Alberta Innovates has helped advance. InnoTech hosted the NRG COSIA Carbon XPRIZE (InnoTech Alberta, 2021) and successfully demonstrated CarbonCure's technology as well as technologies from Air Co, Carbon Corp, CERT and Carbon Upcycling Technologies. These will be discussed further in the "Utilization" section of this report. InnoTech is currently developing technology to enrich CO_2 streams and is also devising new absorber and stripper designs for incremental improvements to amine systems. InnoTech is also developing a process to enrich CO_2 in flue gases with membranes and subsequently purify the concentrated CO_2 with cryogenic technology.

InnoTech has also completed a number of the following carbon capture projects for clients. Much of InnoTech's client work is done in confidence (confidential to the client). Some of the work listed below can only be described a summary level, and other studies cannot be included in this Whitepaper due to client confidentiality.

In addition, studies conducted by the Alberta Innovates-funded Cleaner Power Coalition are summarized here. They are focused on the power sector and examine optimal technology applications for specific power generation methods, as well as novel power generation processes that may be more amenable to carbon capture. In addition, an overview is provided of some of the information obtained by other organizations in the novel capture technology field not supported by Alberta Innovates, InnoTech or Emissions Reduction Alberta. This includes the US Department of Energy (US DOE), the Electrical Power Research Institute (EPRI) and the Global CCS Institute (GCCSI). Each are addressed in the sections below.

3.5.1. Alberta Innovates and InnoTech Studies and R&D

CO_2 Separation Technology for Enhanced Oil Recovery

In 2002 the Alberta Research Council produced a report on CO_2 separation technologies which could be used to supply CO_2 for EOR. The report reviewed existing and promising novel carbon capture processes. The objective of the report was to construct a series of cost curves for various concentrations of CO_2 for the near-term, medium-term and long-term. The report identified CO_2 hydrate, electrical swing adsorption and sorbent energy transfer separation systems as promising future carbon capture technologies (Wong, Payzant, Bioletti, & Feng, 2002).

Hydrogen and Fuel Cell Cluster Feasibility Study

In 2003 Marc Godin was commissioned to write a report that argued for the need for a hydrogen and fuel cell cluster and network. It also described the fuel cell and hydrogen research efforts and technologies at that time (Godin, 2003). The report provided a rationale for hydrogen and fuel cell innovation in Alberta. Innovation to produce high hydrogen fuels, hydrogen from low value feedstocks and cleaner fuels was supported. Fuel cells were considered to be more efficient and scalable than combustion processes and for these reasons innovation in fuel cells was encouraged.

Baseline Cost of Hydrogen

In 2012 a report was prepared for Alberta Innovates - completing a techno-economic assessment of hydrogen produced by SMR and underground coal gasification. The cost of SMR-derived hydrogen with a natural gas cost of $5.00/GJ increased from $2.08/kg without carbon capture to $2.66/kg and $3.02/kg with carbon capture depending upon the site location. Generally, the underground coal gasification scenarios with carbon capture had lower costs for hydrogen. However, as gas prices decrease the SMR cases with carbon capture become more competitive with underground coal gasification (Olateju & Kumar, 2012). This study did not look at other hydrogen production methods such as autothermal reactors (ATRs), which may have an inherently lower capture cost and higher capture rate than SMRs. Underground coal gasification is not currently an active area of development in Alberta.

Ionic Liquids Report

In 2004 A.E. Mather of University of the Alberta was commissioned by Alberta Innovates to study the solubility of CO_2 in ionic liquids. Data for the solubility of hydrogen sulfide in the ionic liquid referred to as BMIM-PF6 has been obtained over a range of temperatures and pressures for the first time. The report concludes that "The use of this ionic liquid for the removal of acid gases is suitable only for bulk removal, when the partial pressures of the acid gases are large. It does not appear to have a role in treatment of natural gases typically found in Alberta" (Mather, 2004).

Membranes

Hollow Fibre Membranes

In 2006 SNC Lavalin produced a report for the Alberta Research Council Inc. (now Alberta Innovates) on the use of hollow fibre membranes for the separation of CO_2 from other gases. It was concluded that:

- "Membranes used as promoters of gas/liquid contact in CO_2 capture applications represent the most promising route to achieving reductions of 20 to 30 per cent in the unit cost of CO_2 capture in the next 5 to 10 years. They could do this through a combination of increasing both the capture and regeneration efficiency of chemical absorption systems, and by simplifying and reducing the size of the necessary equipment; and
- A combination of membrane technology, incremental improvements in the base capture processes and carbon credits could reduce the delivered cost of CO_2 to USD $25/tonne or less. At a constant carbon credit value of $15/tonne, without the membrane component, incremental improvements in existing amine systems are likely to be able to yield delivered CO_2 values in the neighbourhood of USD $30/tonne" (SNC Lavalin, 2006).

The authors also noted that since amines attacked the membranes, KOH with a lower absorption capacity could be used instead.

Membranes for CO_2 Capture

NTNU received partial funding from Alberta Innovates to develop fixed-site-carrier membranes for CO_2 capture. Alberta Innovates and Air Products & Chemicals and several oil companies were involved in the project. These membranes were tested in the lab and large-scale membrane simulations and cost estimates were completed. The membrane is comprised of polysulfone (PSf) fibers supporting a thin polyvinylamine (PVAm) layer with an active amine group that acts as carrier to transport CO_2 through the membrane when humidified. The performance is improved over standard polymeric membranes (NTNU, 2017).

Ceramic Membranes

In 2011 GE Canada in collaboration with the University of Alberta and Alberta Innovates Technology Futures (now Alberta Innovates) received $1.176 million from ERA to develop novel ceramic-based CO_2 capture technology for hydrogen production (Reid & Keshavan, 2020). The objective was to demonstrate the technical and commercial feasibility of novel ceramic membranes in an Alberta context (Reid & Keshavan, 2012). Challenges developing clinoptilolite membrane tubes of sufficient quality to meet specifications and of sufficient H_2/CO_2 selectivity (>25 at 5 PSI) occurred (Reid & Keshavan, 2012). Modelling the system revealed that there were no benefits using the membranes in the natural gas reforming process. The project was stopped after phase 1 was completed, as decided by the program sponsor and team (CCEMC, GE, UA, AITF) (Reid & Keshavan, 2012).

Electrochemical Membrane Systems or Molten Carbonate Fuel Cells

Electrochemical Membrane Evaluation Study Report

In 2012 Alberta Innovates identified molten carbonate fuel cells (MCFCs) as a potentially attractive carbon capture option for reducing GHG emissions from OTSGs. Molten carbonate fuel cells produce power, water and may produce hydrogen. They also appeared to be a potentially low-cost way to capture CO_2. For these reasons it was identified as a promising carbon capture technology. In 2013 Jacobs Consultancy partnered with David Butler and Associates Ltd. to complete a study comparing post combustion capture, molten carbonate fuel cells and solid oxide fuel cells on OTSG and cogens (Jacobs Consultancy, 2013). Molten carbonate fuel cells are also referred to as electrochemical membranes (ECM). The results of this study related to the molten carbonate fuel cells was published in the International Journal of Greenhouse Gas Control (Hill, et al., 2015).

The following list summarizes the highlights of the study:

- Solid oxide fuel cells focused on power generation are poor fits for low-power, high heat demand operations such as steam-assisted gravity drainage (SAGD);
- ECM fuel cells that concentrate CO_2, and incidentally, produce power appear to offer significant economic advantages over conventional capture technologies for SAGD complexes;
- ECM is estimated to offer carbon capture cost in the range of $40/t as opposed to conventional technologies with costs well over $100/t. On an avoided CO_2 basis the benefit for ECM is even larger;
- Any relatively “clean” dilute CO_2 flue gas streams appear to be candidates for capture through the use of ECM fuel cells. (Jacobs Consultancy, 2013); and
- Due to carbon credits (at an emission intensity of 0.88 tonne/MWh) for the export of power, the OTSG ECM case has a levelized cost of steam comparable to an OTSG without CO_2 capture and has a much lower GHG emission intensity (Jacobs Consultancy, 2013).

The report identifies uncertainties regarding capital cost, reliability, operability and maintenance costs. It was recommended that further studies be completed on commercial scale facilities to confirm these costs.

Evaluation of Integrating Molten Carbonate Fuel Cells with a SAGD

Alberta Innovates funded a follow up study on MCFCs and commissioned Jacobs Consultancy in 2015 to study MCFCs integrated into a SAGD facility in greater detail. This report evaluated three SAGD configurations with and without MCFCs.

The reports concludes that, "Therefore, in our opinion, this Study supports the findings from Phase 1, in that the MCFC+CO_2 addition to SAGD CPF can offer substantially lower costs of capture than commercially available amine systems and is a promising technology for CO_2 capture and compression for the purposes of producing CO_2 for EOR or sequestration" (Jacobs Consultancy, 2015). It goes on to state that "Integrating the MCFC+CO_2 represented in the Study as the Combined Electric Power and Carbon Dioxide Separation ("CEPACS") by Fuel Cell Energy into a SAGD CPF is economically limited to power and water, and therefore presents very little technical risk" (Jacobs Consultancy, 2015).

The report identifies uncertainties regarding capital cost, reliability, operability and maintenance costs. It recommended and described further studies which could be completed on commercial scale facilities to confirm these costs.

FuelCell Energy Pre-FEED Study for Demonstration at University of Calgary

In 2016 Stantec and FuelCell Energy completed a pre-FEED study for a molten carbonate demonstration unit at the University of Calgary's combined heat and power plant. The unit would be sized to 255 kWe gross output and would capture 6.4 tonnes per day of CO_2 with a 75 per cent capture rate (Stantec, 2016). This project was partially funded by Alberta Innovates. The demonstration project was estimated to cost $15,562,000 and have an annual operating cost of $956,800.

ERA also appears to be in discussions with Cenovus in partnership with Shell and Devon to provide the funds to demonstrate MCFCs (ERA, 2020b), although this project has merged with the CNRL project which is hosted at the Shell site, with Cenovus as one of the project partners.

Fuelcell Energy Pre-FEED Study for Demonstration at Scotford

In 2017 Alberta Innovates funded a pre- Front End Engineering Design (FEED) study by Jacobs for a MCFC demonstration unit. The report states that the system could separate 70 per cent of the flue gas sourced CO_2 and produce power at the same time. The Study looked at two CO_2 sources, a process heater at the Shell Scotford facility and a once-through steam generator (OTSG) at a Husky in situ facility. The MCFC plant would increase the capture rate up to 90 per cent but with reduced capacity relative to operating at 70 per cent capture rate. The system was designed to purify and pressurize the CO_2 stream to pipeline specifications (Jolly, 2017). The cost estimates came in very close, with the Shell site at $21.61 million vs. the Husky site at $21.60 million (Jolly, 2017).

In May of 2021 Canadian Natural announced that it would go ahead with the 1.4 MW pilot demonstration at the Scotford Upgrader (Morgan, 2021). This announcement indicated that 40 per cent of the funding for this project would come from ERA. ERA also appears to be in discussions with Cenovus in partnership with Shell and Devon to provide the funds to demonstrate MCFCs (ERA, 2020b), although this project has merged with the CNRL project which is hosted at the Shell site, with Cenovus as one of the project partners.

Solid Sorbents

Solid Sorbents Gap Analysis

In 2011 Alberta Innovates – Technology Futures produced a report entitled "Gap Analysis for Solid Sorbents for Post Combustion CO_2 Capture". The report stated that amine-functionalized solid sorbents had the greatest potential. However, research in this area is at an early stage and scale-up testing has not yet been done (Sarker & Chambers, 2011). The authors also indicated that activated carbon and zeolite-based sorbents are low-cost and have lower regeneration energy needs but they have a lower capture capacity and selectivity and are therefore not suitable for post-combustion capture. Metal-organic frameworks (MOFs) were examined as well but further research is needed to determine potential applicability under flue gas conditions (Sarker & Chambers, 2011). The report concluded that further R&D on solid sorbents should continue, and techno-economic analysis studies be conducted under different contactor configurations with appropriate process design (Sarker & Chambers, 2011).

Solid Sorbent Study

In 2013 the University of Ottawa (UO) and Pacific Northwest National Laboratory (PNNL) were commissioned by Alberta Innovates to test UO's absorbents in PNNL's adsorbent bed system. The key conclusions from the study are (Sayari & Liu, 2013):

- No steam is needed in the process resulting in large savings;
- 13.5 per cent more power output can be produced when adsorption is used over amine capture per unit of coal burned;
- Pressurizing the CO_2 for sequestration will account for a significant energy footprint regardless of capture method;
- The capital cost with the adsorption process is estimated to be $312 and $256/kW for 3.5 wt per cent and 7.0 wt per cent CO_2 working capacity, respectively, which is much less than $790-950/kW estimated for the amine process;
- The variable operation cost is dominated by the electricity consumption to drive the separation process; and
- The adsorbent cost is minor as long as the adsorbent has a reasonable lifetime such as >5 years.

It was recommended that further work be completed to deliver robust adsorbents, understand the kinetics and operating windows of the materials, optimize the design and validate the key assumptions made in the economic analysis.

InnoTech Solid Sorbents Study

In this project, research groups worked on solid sorbents for CO_2 capture from flue gas with superior performance and desired economic attributes. InnoTech designed and built a lab-scale tubular reactor to use thermal swing capture of CO_2 from a simulated flue gas mixture to evaluate the performance of the solid sorbents developed. Several reports were published for this project (Samanta, Ahoa, Shimizu, Sarkar, & Gupta, 2012).

InnoTech - Hitachi Chemical Solid Sorbent Evaluation

This three-year project evaluated the performance of Hitachi Chemical's proprietary solid sorbent for CO_2 capture using simulated flue gas and air. The results of this study are not publicly available.

Syngas

Carbon Capture from Sour Syngas

In 2010 Air Products produced a report for Alberta Innovates on the use of a sour Pressure Swing Adsorption (PSA) to remove hydrogen from sour syngas from a gasification process with a subsequent process to purify the remaining gases by oxidizing the remaining H_2S to form sulfuric acid which can be removed to leave relatively pure CO_2. Air Products considered four cases:

- Conventional Power: Gasification with Rectisol to produce H_2 for power production;
- Sour PSA Power: Gasification with sour PSA to produce H_2 for power production;
- Conventional Hydrogen: Gasification with Rectisol to produce H_2; and
- Sour PSA Hydrogen: Gasification with sour PSA to produce H_2 (Air Products, 2010).

Jacobs completed the technical and economic feasibility study on a conceptual plant. A sour PSA was tested at the Energy & Environmental Research Center (EERC). Portions of a pre-FEED design for a prototype were also completed. Air Products completed simulations of the performance of the PSA. In both the power and hydrogen cases the sour PSA is expected to lead to lower capital costs than using Rectisol. However, the operating costs associated with using a sour PSA are expected to be greater than that for Rectisol. The report indicates that if the value for the additional power produced in the sour PSA case, if sulfuric acid can be sold rather than disposed of and other design changes are made this can significantly reduce operating costs (Air Products, 2010).

The report concluded that "Despite the capital cost benefits and production benefits, at least for the power case, significant challenges exist with respect to operating costs, largely associated with acid production and uncertainty in the capital costs associated with new equipment" (Air Products, 2010).

Pre-Combustion CO_2 Capture from Syngas

This project was led by GE with the participation of the University of Alberta. The project developed a zeolite base membrane to separate hydrogen from Syngas. This work was funded by AERI and was further funded by the CCEMC for an additional two years. An intermediate temperature molecular sieve membrane with high hydrogen selectivity to capture CO_2 from syngas was developed. The goal was to introduce a molecular sieve-based gas separation unit in a coal gasification plant downstream of the water-gas shift reactor to capture CO_2 and produce hydrogen. The project demonstrated the proof of concept at a lab scale.

Neumann CO_2 Capture System

Neumann Systems Group, Inc. in 2010 tested their CO_2 capture technology at the EERC. Alberta Innovates provided a portion of the funding for the project. Jets form relatively flat sheets of absorbent with high surface area. Flue gas is passed through these sheets and CO_2 is absorbed into the absorbent. The project found that the overall size of the absorber could be reduced by as much as 50 per cent with CO_2 removal rates over 90 per cent when used in conjunction with an advanced solvent (Pavlish, Kay, Fiala, & Stanislowski, 2013). The reduction in size would translate to an estimated 50 per cent cost reduction relative to conventional absorber columns (Pavlish, Kay, Fiala, & Stanislowski, 2013). As a result, the costs for the NeuStream system are expected to be significantly lower than for conventional post-combustion CO_2 capture.

CO_2 Solutions Enzymatic CO_2 Capture

CO_2 Solutions Inc (CSI) received $500,000 from the CCEMC to conduct laboratory and bench-scale testing of their enzymatic system for CO_2 Capture. Over the course of the 24-month project, from May 2012 to May 2014, CSI's enzymatic CO_2 capture process was successfully advanced from the laboratory to the large-bench scale (~0.5 tonnes/day) for application to OTSG operations and other large emissions sources in the oil sands and beyond (Fradette, 2014).

In the Project, CSI demonstrated at pre-pilot scale several significant benefits compared to conventional amine processes, including a 30 per cent+ savings on CO_2 capture costs (CAPEX and OPEX), or <$50/tonne vs. $70 for conventional amine technology, in line with a CO_2 price point required for EOR and other reuse applications. This included a ~90 per cent reduction in energy costs resulting from the ability of the process to operate using waste heat streams (Fradette, 2014).

In 2015 CSI announced the techno-economic results of testing completed at the EERC. In it they estimated a capture cost of approximately $39 /t CO_2 based on 90 per cent CO_2 capture from flue gases of a typical coal-fired power plant at full scale, including CO_2 compression. This surpasses the 2025 carbon capture target set by the U.S. Department of Energy (DOE) of $40/t (Fradette, 2014).

Chemical Looping

Lab Scale Chemical Looping Combustion

The InnoTech technical team worked for several years on Chemical Looping Combustion (CLC) technology, built a fluidized bed CLC batch reactor and developed oxygen carriers for CLC. CLC is a high-temperature process (700°C-1000°C), typically consisting of two interconnected fluidized beds, one acting as an air reactor (reduced metal solid carrier or its derivatives are oxidized) and a fuel reactor (fuel is oxidized resulting in reduced metal oxide for recycling to the air reactor). One of the main goals of the InnoTech technical teams was to develop high-performance oxygen carrier granules with the following attributes – mechanically robust (high attrition resistance & resistance to fragmentation in cyclic operation), increased oxygen capacity (≥10 wt per cent), high reactivity, intergranular agglomeration resistance, chemical performance degradation resistance, sulphur tolerance and coking resistance. Several papers were developed from this work (Yamarte, Paxman, Sarkar, & Chambers, 2014).

Chemical Looping Combustion in a Fluidized Bed Test Rig

In 2010 a lab scale demonstration test rig was operated to better understand chemical looping combustion (CLC). The main goal of the project was to study the effect of sulphur in the form of H_2S on the CLC reactions and the oxygen carrier. H_2S was found to deactivate the oxygen carrier causing a decrease in combustion efficiency. Low concentrations of H_2S below 100 ppm in methane were recommended. It was recommended that further studies and simulations be completed to better understand the CLC process and to make improvements to it (Nikoo, Yamarte, & Chambers, 2010).

Carbon Engineering Direct Air Capture

In 2016 Carbon Engineering (CE) completed a pilot demonstration of their CO_2 air capture system. The CCEMC provided $500,000 to this project. The four-phase project resulted in a 1 tonne CO_2/day pilot plant development and used natural gas as an energy source with exhaust CO_2 cycled to the capture unit, resulting in the delivery of 1.5 tonnes of CO_2 per tonne of CO_2 captured from the air using 8.7GJth/t CO_2 (Corless, 2016). Of note, Worley has been engaged to complete a FEED study for the "1PointFive" DAC project which is proposed to initially capture 500,000 t CO_2/yr in the United States. Carbon Engineering is also helping to design and engineer a DAC facility expected to capture more than 500,000 t CO_2/yr in the UK (Carbon Engineering, 2021). The significant energy usage required by this technology implies that its deployment would be best suited in jurisdictions with surplus renewable or low carbon energy and sufficient geological storage capability.

Cryogenic Carbon Capture with Energy Storage (CCC ES ™)

Sustainable Energy Solutions (SES) completed a report on cryogenic separation of CO_2 with energy storage in 2015. The CCEMC provided $490,000 to fund this project. In this report CO_2 is captured from a coal plant. The capture system freezes out air contaminants including CO_2. Refrigerant is stored during low power prices and used to cool the system during high power prices. The energy storage system studied is expected to have a high efficiency. The cost to capture CO_2 is expected to be significantly lower than conventional post combustion capture. Since there is significant heat exchange between the streams SES claims there is a significant energy benefit compared to traditional power combustion capture systems. In this project the refrigerant is natural gas, and the refrigeration system is a compressor. For energy storage, low-cost power is used to run the compressor so that additional natural gas refrigerant is compressed, cooled and stored as LNG (Baxter, 2015).

Some of its distinguishing characteristics compared to the leading alternatives (i.e., advanced amine systems) include:

1. Consumes about half of the energy;
2. Costs less than half;
3. Stores energy in a highly efficient, grid-scale, rapidly responding process;
4. Retrofits to existing coal, natural gas, biomass, cement kiln, and other systems;
5. Captures most pollutants (CO_2, SO_x, NO_x, Hg, PM_{xx}, VOCs, etc.) in a single, multipollutant, platform;
6. Recovers flue gas moisture, reducing water demand; and
7. Capable of very high capture rates at modest costs.

The study concluded that when compared to advanced amine systems, the CCC ES system consumed half of the energy, cost less than half, can be retrofitted to several systems, captures most pollutants (including CO_2, SO_x, NO_x, Hg, PM_x, VOCs, etc.), and recovers flue gas moisture thereby reducing water demand (Baxter, 2015).

The next steps in the commercialization plan of this technology include a market analysis and to increase the scale and duration of CCC ES™ testing to the same level as the CCC skid demonstrations, demonstrate the CCC ES™ technology in a field test, and integrate CCC ES™ into the next scale up of the Cryogenic Carbon Capture™ technology (Baxter, 2015).

Solid Oxide Fuel Cells

Solid Oxide and Cogeneration with Carbon Capture

In 2014 Jacobs Consultancy partnered with David Butler and Associates Ltd. to complete a study comparing cogeneration and solid oxide fuel cell (SOFC) production of steam and power, with and without carbon capture, for use in a steam assisted gravity drainage facility. The cogeneration systems produced about 150 MW of power in excess of facility needs. However, the SOFC systems produced more than 900 MW of power in excess of facility needs. The large amount of power sold by the SOFC cases lead to negative costs for steam. The cost of capture for the cogen was estimated to be about $141.7/t. The cost of capture for the SOFC was estimated to be $25.50/t because it cost much less to purify the CO_2 exiting the system. The SOFC case with carbon capture produced steam and power with almost no CO_2 emissions. The cogeneration case captured 90 per cent of the CO_2 emissions. 900 MW of power production is roughly four years of electricity growth in Alberta. Given the mix of generation in Alberta, there is some opportunity to displace non-cogeneration forms of baseload generation. The study concluded that SOFC are power producers and not well matched to thermal in-situ requirements. SOFC can be configured as combined cycle power plants. The study did not however evaluate using the clean power from the SOFC to make some additional clean steam or to use the power to directly heat reservoirs. In addition, baseload clean power will be required in the future to support industrial electrification and electric vehicles (Jacobs Consultancy, 2014).

Dry Reforming Solid Oxide Fuel Cell (SOFC) Technology

A novel fuel cell reactor was developed to co-produce electricity and CO through CO_2 reforming of methane. Introducing oxygen into the reaction via the fuel cell made the reforming of CH_4 so favourable that a voltage comparable to the standard H_2-O_2 fuel cell was produced that varies from 0.96 V at 500°C to 1.09 V at 800°C. Several journal articles were written describing this work (Hua, et al., 2017).

Oxy-fuel with Carbon Capture for OTSG

Praxair and a consortium of oil companies received $2.5 million from ERA to complete an oxy-fuel demonstration at a Suncor OTSG (ERA, 2020c). The report indicated that there are no fundamental technology limitations for retrofitting a SAGD OTSG boiler for oxy-fuel combustion and operating it continuously (ERA, 2020c). The report concluded that boiler performance was nearly identical between air-fuel and oxy-fuel and the same steam quality and steam flow were achieved compared to loads under air operation due to a similar balance between the heat transfer to the boiler evaporator and the economizer (ERA, 2020c). The report indicated that fuel use was reduced by 5 per cent and NOx emissions were reduced by 85 per cent and virtual elimination of CO emissions (ERA, 2020c). The report concluded that the study was very successful, and there are no general limitations for retrofitting OTSGs for oxy-fuel operation at full scale with appropriate design measures in place (ERA, 2020c). Scale up recommendations are provided in the report (Tian, Bool, Cates, & Laux, 2015).

Vacuum Swing Absorption Development

A two-bed Vacuum Swing Adsorption (VSA) system was designed and built at InnoTech in collaboration with collaboration Prof. Rajendran's research group at the University of Alberta. This unit is capable of completing the parametric study of CO_2 capture from flue gas to develop operational parameters and scale up of the system (Perez, Sarkar, & Rajendran, 2019).

3.5.2. Canadian Clean Power Coalition Gasification Studies

Integrated Gasification Combined Cycle (IGCC) FEED Study

In 2004 the CCPC completed a report with the support of the Alberta Energy Research Institute (AERI), a precursor to Alberta Innovates, to study ways to reduce various emissions from coal fired power generation including CO_2 (Stobbs, 2004).

It was concluded that "Gasification was shown to be a potentially low-cost CO_2 capture technology; however, gasification requires significant development to improve availability" (CCPC, 2011a).

In 2008 the CCPC, with support from the AERI completed a Phase II report which further studied gasification (Stobbs, 2008). That report concluded that the costs of all the technologies studied were high and were dependent on the type of coal used. The technologies were also at a range of development stages, so comparisons between the technologies were difficult (CCPC, 2011a). Consequently, it was recommended that detailed site-specific studies be completed for a wide variety of technologies to make a final technology selection (CCPC, 2011a).

In 2011 the CCPC during its third phase of work completed several studies on gasification, including a Front-End Engineering Design (FEED) study for an approximately 240 MWnet integrated Gasification Combined Cycle (IGCC) facility with carbon dioxide capture. This project included contributions from Capital Power Corporation (CPC), the CCPC, Alberta Innovates: Energy and Environment Solutions (AIEES) (now Alberta innovates), and NRCan. The study goals were to develop accurate cost and techno-economics with the intent of building the facility at Capital Power's Genesee Generating Station in Alberta. (CCPC, 2011b). The emission intensity of the plant was estimated to be 0.32 t/MWh with a CO_2 capture rate of 64 per cent. The report provided a long list of key learnings. Several of the key technical learnings were:

- It is important to quantify the properties of the feedstock as these properties will have a significant impact on the whole gasification system;
- Selection of the gasifier is highly dependent upon the properties of the feedstock;
- Integration opportunities can reduce costs; and
- Given the complexity of the gasification system, commissioning and troubleshooting of the system will take more time than a less complex power plant.

It was recommended that further work be conducted to better understand gas turbine operation on a high hydrogen fuel and the use of flux to optimize slag characteristics. It was also noted that next generation gasification and air separation technologies may provide cost reductions and could be studied. Opportunities to integrate IGCC into polygeneration facilities and breakthrough commercial technologies with the potential to reduce capital and operating costs are also areas for further study.

Advanced Gasification Studies for Power and Hydrogen

Based on the results of the IGCC FEED study, the CCPC in Phase III of its work studied ten optimized IGCC carbon capture schemes to produce power and hydrogen. Four gasification technology licensors agreed to participate in the study. The emission intensity of the power and hydrogen produced were very low thanks to the use of carbon capture. The purpose of this study, conducted by Jacobs, was to evaluate multiple gasification technologies that are commercially available with licensor enhancements that are anticipated to be incorporated into their designs within the next 5 to 10 years. The capture of CO_2 for the power cases was expected to be above 90 per cent except for the SES U-gas case which was at 78 per cent (CCPC, 2011c).

This study suggested that there may be other gasification technologies which may lead to a lower cost of power than the Siemens technology chosen for the IGCC FEED study. However, the cost of power for all the cases was more than \$200/MWh and more than twice that predicted for the reference coal plant without CCS (CCPC, 2011c).

This study also evaluated several processes to produce blue hydrogen. The study suggests that the cost to capture 50 per cent of the CO_2 from the process stream in a SMR only increases the cost from \$1,661/t H_2 to \$1,875/t H_2 for a capture cost of \$59/t CO_2. The cost of hydrogen for 90 per cent CO_2 capture from an SMR rises to \$2,558/t H_2 and the cost of capture increases to \$104/t CO_2 (CCPC, 2011c).

Very material decreases in the cost of gasification are required before it can likely be a competitive process for creating clean power or hydrogen.

EPRI Gasification Roadmap Study

The EPRI Roadmap Study included analysis of ten different technological improvements to gasification over current state of-the-art equipment as represented by the base case. These technologies included coal beneficiation, oxygen production, high temperature and pressure sulphur recovery, hydrogen membranes, advanced CO_2 capture, CO_2 purification and pressurization, advanced gas turbines and supercritical steam turbines. Additionally, two cases were created to study the aggregate impacts of several technologies on advanced IGCC plants in the 2020 and 2030 timeframes. The 2030 case included an advanced, compact gasifier under development by Pratt & Whitney Rocketdyne (CCPC, 2011c). The study indicated that none of the technologies examined would be sufficient to reduce capture costs to similar levels as other power plants with available CO_2 mitigation technologies, and that significant advancements in multiple areas are required to bring down costs, including some promising ideas that were outside of the study scope (CCPC, 2011c).

Advanced IGCC Partial Carbon Capture

In 2014 the CCPC completed its fourth phase of study work (CCPC, 2014a). In this phase of work it studied IGCC advances with partial capture of CO_2 using Alberta coal. Table 4 describes the various technologies considered in the study.

Table 4: Description of Cases (CCPC, 2014b)

Case	1	2	3	4	5-2	5-4	6
Air Separation	Cryogenic	Cryogenic	Cryogenic	Cryogenic	Air Prod ITM	Air Prod ITM	Cryogenic
Gasifier	AR	AR	AR	SES	AR	SES	CB&I
Shift	Sour	Sour	Sour	Sour, with bypass	Sour	Sour, with bypass	None
Sulphur Recovery	LO-CAT	LO-CAT	LO-CAT	LO-CAT	LO-CAT	LO-CAT	Selexol Claus/ SCOT
CO_2 Recovery	Partial Condensation	PSA	Membrane	Selexol	PSA	Selexol	Selexol
Gas Turbine	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas	GE 7F Syngas
Steam Turbine	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat	3 Pressure Reheat

The IGCC partial capture cases have first-year costs of power much lower than technologies configured to capture 90 per cent of CO_2. In addition, many of the IGCC partial capture cases are forecasted to have costs of power similar to a new super critical coal plant with partial CO_2 capture (CCPC, 2014b).

Partial capture of CO_2 is expected to significantly reduce the cost of producing power from IGCC plants compared to plants capturing 90 per cent of the CO_2. Many of the cases have a first-year cost of power similar to a super critical coal plant with 60 per cent capture. Clearly further advances are required before IGCC with partial capture can complete with NGCC (CCPC, 2014b).

In-situ Coal Gasification

In Phase IV of the CCPC's work it studied in-situ coal gasification (ISCG) with carbon capture to meet a GHG emission intensity of 0.42 t CO_2/MWh. The report concluded that the economic results for ISCG were significantly better than a pulverized coal power plant with post-combustion carbon capture, and similar to a traditional pulverized coal power plant, with the required first year selling price for power for ISCG at approximately one third of the price required for a comparable IGCC facility ($82/MWh compared to $247/MWh) (CCPC, 2014c).

It was recommended that additional options identified during the study for even more economically attractive ISCG flowsheets for power generation be evaluated (CCPC, 2014c).

3.5.3. CCPC Studies of Cleaner Power Options

Advanced Power Cycles

In Phase IV of CCPC's work a study was completed by the Electric Power Research Institute (EPRI) to study advanced power generation cycles with low CO_2 emissions in coal plant repowering and greenfield applications. The technologies included:

- Advanced, Ultra-Supercritical (AUSC) Steam Topping Cycle;
- Closed Brayton Topping Cycle;
- Magneto-hydrodynamic Topping Cycle;
- Organic/Rankine Bottoming Cycle;
- Turbocharged Boiler with CO_2 Capture;
- Pressurized Oxy-coal and Chemical Looping Combustion; and
- Closed Brayton Bottoming Cycle.

Conclusions were reached regarding what is required to help advance each cycle. Generally, this included monitoring the advancement of the technologies and completing further studies to understand the technology costs in more detail particularly if advancements had been made in the technologies (CCPC, 2014d).

Natural Gas Power Generation with Low GHG Emissions

In Phase IV of the CCPC's work, several lower GHG emitting processes to produce power using natural gas as a fuel were studied with GHG emission intensities of about 0.2 t/MWh.

The technologies evaluated in this study were: Reference NGCC, an NGCC with advanced solvent post combustion capture with a steam boiler and back pressure turbine and a second option extracting heat from the heat recovery steam generator (HRSG), molten carbonate fuel cells - one with 70 per cent capture and one with recycle to increase capture, an NGCC with low carbon fuel (hydrogen) from an ATR with amine scrubbing and one with a PSA, NGCC with chemical looping combustion and a direct-fired supercritical CO_2 Open Brayton Cycle (Net Power) (CCPC, 2017a).

Both the amine scrubbing and molten carbonate fuel cell (CEPACS) cases had similar costs of power. It is clear that using clean hydrogen to fuel a gas turbine will likely not be economical compared to amine scrubbing or CEPACS. The Open Brayton Cycle is expected to have a relatively high cost for generating clean power (CCPC, 2017a).

More work is required to understand and refine the costs for these technologies.

Advanced Carbon Capture Process Review

In Phase IV of CCPC's work they commissioned EPRI to study 21 advanced post-combustion capture technologies. Those technologies included:

- Advanced solvents
  - 3H Company, LLC: Self-concentrating solvent
  - Dupont: Advanced amine-based solvent
  - CEFCO Global: Potassium carbonate, shockwaves
  - CO_2 Solutions: Enzyme-enhanced solvent
  - Codexis: Enzyme development
  - Ion Engineering: RTIL solvent
  - University of Notre Dame: Ionic liquids
- Adsorbents
  - ADA-ES: Adsorbents and process concept
  - CACHYS: Metal carbonate salt
  - Innosepra: Proprietary adsorbent
  - InvenTyS: Veloxotherm (activated carbon adsorbent)
  - SRI International: Carbon-based sorbent
  - TDA Research: Alkalized Alumina
  - University of California at Berkeley: MOFs
- Membranes
  - GTI: Hybrid membranes
  - MTR: Polaris™ membrane

- RTI International: Hollow fiber polymeric membranes
    - University of Colorado: Gelled Ionic liquid membrane
- Cryogenic
    - ATK: Inertial CO_2 Extraction System (ICES)
    - Sustainable Energy Solutions: Cryogenic CO_2 Capture
- Ca Looping
    - Several Researchers

The report concluded that all of the processes reviewed have significant potential advantages but they also all have significant challenges to overcome. Further, it concluded that none of these processes appear to have the potential to provide major breakthroughs.

The report suggested that the concepts that could benefit from help in moving their development forward included ionic liquids, enzyme promotion of solvents, solid sorbents in the form of MOFs, the cryogenic processes, and those concepts that employ phase-change materials.

Future work in this area that might be considered could include:

- Updating of status of the processes and identification of previously unknown processes;
- Investment into one or more of the developing processes:
    - Through working with EPRI; and
    - Through funding independent projects; and
- Complete a molten carbonate fuel cell project (CCPC, 2014e).

Repowering of Coal Plants

The CCPC completed a final report of its fifth phase of study work in 2017 (CCPC, 2017b). In this phase of work it studied various ways to repower existing coal plants to produce cleaner power using natural gas as a fuel. Repowering refers to removing the existing coal furnace and boiler and replacing it with a different heat source to provide steam to the remaining steam turbines. The GHG emission intensity of all repowering cases was targeted to be 0.42 t CO_2/MWh. The report compared an NGCC without carbon capture to coal plants without carbon capture, MCFC, biomass cofiring in a coal plant, several post-combustion capture (PCC) cases, solid oxide fuel cells and coal fired fluidized bed combustion.

The least cost option was a new gas turbine without carbon capture used to provide steam to the existing steam turbines. The next least cost repowering option was the MCFC case with carbon capture. The power cost for MCFC is expected to be comparable to partially firing biomass into the coal boiler. All the other post-combustion capture cases were expected to have higher costs of power than these cases. The least cost amine post-combustion capture case is the one where a large natural gas fired turbine provides the steam required by the capture unit (CCPC, 2017c). A more detailed report for this study was published as part of GHGT-13 and shows the results for Nova Scotia coal (Butler, Hume, Scott, & Lampercht, 2017).

Additional study work to refine the design and costs of MCFC was recommended.

Fuel Cell Repowering of Coal Plant

In CCPC's phase IV of work, it completed a more detailed study of repowering a coal plant with MCFCs compared to using post-combustion capture to achieve a GHG emission intensity of 0.42 t CO_2/MWh.

The MCFC case had a lower cost of power than the amine post-combustion power case. Likewise, the avoided cost and capture cost for the MCFC cases were expected to be lower than for amine scrubbing. This result should also be true for flue gases based on natural gas as a fuel. The cost to retrofit a coal plant with MCFCs is forecasted to lead to power costs a bit higher than for a new NGCC. This is remarkable in that the capture cost cases include life extension costs and costs to complete flue gas desulfurization (CCPC, 2017d).

One of the virtues of MCFC technology is that no steam is required from the power plant to capture CO_2; therefore, expensive and extensive modifications to the plant steam cycle are not required as with other post-combustion capture options. In addition to capturing CO_2, the flue gas processed by the fuel cells will be stripped of most of its sulfur and NO_x components. This will substantially reduce the air emissions from the coal plant. The fuel cell is also a net producer of clean water and power.

Greenfield Coal Power Generation with Low GHG Emissions

In Phase V of the CCPC's work, a study was completed assessing new ways to produce power from coal as a fuel with low GHG emissions. The technologies evaluated in this study were post combustion capture on a new coal plant, closed Brayton cycle, oxy pressurized fluidized bed combustion and open Brayton cycle. The GHG emission intensity for the first two cases was targeted at 0.42 t/MWh and because of design limitations the GHG emission intensity of the final two cases was about 0.1 t/MWh. None of the cleaner coal cases had a lower power cost than a new NGCC (CCPC, 2017e).

Table 5: First Year Cost of Electricity

	NGCC	PCC	Closed Brayton	Oxy PFBC	Open Brayton
1^{st} Yr Cost ($/MWh)	61.9	171.5	217.9	183.3	130.9

Oxyfuel Retrofit of Coal Plant

The Canadian Clean Power Coalition cooperated with New Energy and Industrial Technology Development Organization (NEDO) to study oxyfuel retrofitting of a coal plant to capture CO_2. Permission was granted to release a public version of the results, but the report was not released by the CCPC. The study showed promising economic results compared to an NGCC given the understanding of the GHG regulations which would face coal plants at the time the study was completed. A subsequent private oxyfuel study was completed by NEDO. These studies assumed an economic value for the nitrogen produced which helped improve the economics.

3.6. New Carbon Capture Technologies to Consider

A large number of carbon capture technologies are being developed around the world that are not currently supported by Alberta Innovates. An attractive form of carbon capture technology is one with low cost and which can lead to large volumes of CO_2 captured. The following provides information on carbon capture technologies which are being developed and deployed. It also identifies where information exists describing and evaluating novel carbon capture technologies. As discussed below, work could be done to identify promising carbon capture technologies for further development by Alberta Innovates. The information provided below could help Alberta Innovates identify those promising carbon capture technologies.

3.6.1. US DOE-Funded Projects

The United States Department of Energy is one of the largest funders of new carbon capture technologies in the world. In May 2020 the US Department of Energy published a comprehensive compendium report describing more than 130 carbon capture technologies they had funded up that point in time (US DOE, 2020a). The NRECA has produced a report describing the issues with various classes of carbon capture and several of the technologies developed in the May 2020 compendium report (NRECA Coop, 2021).

The US DOE has a database of about 80 active carbon capture projects it has funded. They are listed under the technical area Point-Source Carbon Capture in the database. There is also information for many pre-combustion and post-combustion capture projects which have been completed (NETL, 2021a) The US DOE has also identified carbon capture technologies it plans to help develop (US DOE, 2021a).

The US DOE has also funded several CCUS initiatives in the past several years:

- The US DOE is managing the "FLExible Carbon Capture and Storage" (FLECCS) study to evaluate carbon capture technologies which will allow power plants to cycle up and down (US DOE, 2020b);
- In October 2021 the US DOE announced funding for 12 novel carbon capture projects (US DOE, 2021c);
- In August 2021 the US DOE announced funding for nine novel projects to capture CO_2 directly from the air (US DOE, 2021d);
- In September 2020 the US DOE announced funding for 27 projects capturing CO_2 from the air and from industrial sources (US DOE, 2020c); and
- The US DOE has also funded large scale testing of three next-generation technologies at the Technology Centre Mongstad (TCM) in Norway (US DOE, 2018).

The results of these studies will be valuable in determining next-generation carbon capture technologies for a wide range of applications.

3.6.2. EPRI CO_2 Post-Combustion Capture Process Database

EPRI maintains a database of CO_2 post-combustion capture processes. The database has information on the supplier, a description of the process, perceived advantages and challenges, a status report and an EPRI perspective for each carbon capture technology. EPRI also maintains a novel cycles database as well. The purpose of these databases is to help people better understand the advantages and challenges of new carbon capture technology. Specifically, the objective of the databases is to help people understand the characteristics of these technologies, to support decisions about which technologies warrant further development, and to consider when these technologies might be commercially available. These databases are available only to participants in EPRI Program 222. EPRI also manages the CO_2 Capture and Storage Deployment Acceleration (CO_2DA) program which helps to accelerate the development of CCS for power generation. In addition, EPRI runs the Low-Carbon Resources Initiative (LCRI) to help advance the development of low-carbon technologies. (Bhown, 2021).

3.6.3. Global CCS Institute Resources

The Global CCS Institute has assessed the technology readiness level and status of several dozen carbon capture technologies as shown in Table 6 below.

Table 6: TRL Assessment of Key Carbon Capture Technologies. (Kearns, Liu, & Consoli, 2021) from original source (IEA GHG, 2014)

TECHNOLOGY		KEY VENDORS	TRL 2014	TRL 2020	PROJECTS
Liquid Solvent	Traditional amine solvents	Fluor, Shell, Dow, Kerr-McGee, Aker Solutions, etc	9	9	Widely used in fertilizer, soda ash, natural gas processing plants, e.g. Sleipner, Snøhvit, and used in Boundary Dam since 2014
	Physical solvent (Selexol, Rectisol)	UOP, Linde and Air Liquide	9	9	Widely used in natural gas processing, coal gasification plants, e.g. Val Verde, Shute Creek, Century Plant, Coffeyville Gasification, Great Plains Synfuels Plant, Lost Cabin Gas plant
	Benfield process and variants*	UOP	-*	9	Fertiliser plants, e.g. Enid Fertiliser
	Sterically hindered amine	MHI, Toshiba, CSIRO, etc	6-8	6-9	Demonstration to commercial plants depending on technology providers, e.g. Petra Nova carbon capture
	Chilled ammonia process*	GE	6*	6-7	Pilot tests to demonstration plant feasibility studies
	Water-Lean solvent	Ion Clean Energy, CHN Energy, RTI	4-5	4-7	Pilot test and commercial scale FEED studies: Ion Clean Energy's Gerald Gentleman station carbon capture, CHN Energy's Jinjie pilot plant
	Phase change solvents	IFPEN/Axens	4	5-6	DMX™ Demonstration
	Amino acid-based solvent*/ Precipitating solvents	Siemens, GE	4-5	4-5	Lab test to conceptual studies
	Encapsulated solvents	R&D only	1	2-3	Lab tests
	Ionic liquids	R&D only	1	2-3	Lab tests
	Enzyme Catalysed Absorption	CO_2 solutions	1	8	30 tpd commercial facility in Quebec
Solid adsorbent	Pressure Swing Adsorption/Vacuum Swing Adsorption	Air Liquide, Air Products, UOP	3	9	Air Products Port Arthur SMR CCS
	Temperature Swing Adsorption (TSA)	Svante	1	5-7	Large pilot tests to FEED studies for commercial plants
	Sorbent-Enhanced Water Gas Shift (SEWGS)	ECN	5	5	Pilot tests, e.g. STEPWISE
	Electrochemically Mediated Adsorption	R&D only	1	1	Lab test

TECHNOLOGY		KEY VENDORS	TRL 2014	TRL 2020	PROJECTS
Membrane	Gas separation membranes for natural gas processing	UOP, Air Liquide	-*	9	Petrobras Santos Basin Pre-Salt Oil Field CCS
	Polymeric Membranes	MTR	6	7	FEED studies for large pilots
	Electrochemical membrane integrated with MCFCs	FuelCell Energy	-*	7	Large pilots at Plant Barry
	Polymeric Membranes / Cryogenic Separation Hybrid	Air Liquide, Linde Engineering, MTR	6	6	Pilot studies
	Polymeric Membranes/ Solvent Hybrid	MTR/ University of Texas	-*	4	Conceptual studies
	Room Temperature Ionic Liquid (RTIL) Membranes	R&D only	2	2	Lab tests
Solid-looping	Calcium Looping (CaL)	Carbon Engineering	6	6-7	Feasibility/cost studies for commercial scale
	Chemical Looping Combustion	Alstom	2	5-6	Pilot tests
Inherent CO_2 capture	Allam-Fetvedt Cycle	8 Rivers Capital	2	6-7	50 MW Demonstration Plant in La Porte
	Calix Advanced Calciner*	Calix	-	5-6	Large pilot LEILAC

* not assessed in IEAGHG 2014/TR4 report.

The Global CCS Institute also provided the partial pressures of various sources of CO_2 as shown in Table 7.

Table 7: Partial Pressures of CO_2 in Various Sources of CO_2 (Kearns, Liu, & Consoli, 2021), from original sources (Bains, 2017), (Global CCS Institute, 2015), (IEA GHG, 1999), (Grantham Institute, 2014)

INDUSTRY	POINT SOURCE	CO_2 PARTIAL PRESSURE (WET) (KPA)	GAS STREAM PRESSURE (KPA)	INHERENT CO_2 CAPTURE
Power	Natural gas combined cycle (NGCC) power plant	3.8 – 4.6	Atmospheric***	No
	Coal fired-power plant	12.2 – 14.2	Atmospheric***	No
	Biomass/waste-fired power plant	10.1 – 12.2	Atmospheric***	No
Power/ Industrial Heat	Natural gas-fired power and/or heat plant (Open Cycle)	4.1 – 8.1	Atmospheric***	No
Petroleum Refining / Petrochemicals	fluid catalytic cracking	10.1 - 14.2	Atmospheric***	No
	Process heater	8.1 - 10.1	Atmospheric***	No
	Ethylene production steam cracking	7.1 - 12.2	Atmospheric***	No
	Steam methane reforming hydrogen production	300 – 480	2000 – 3000	No
	Ethylene oxide production	> 92	Atmospheric***	Yes
Cement	Kiln flue gas	~ 18	Atmospheric***	No
	Pre-calciner	20 - 30	Atmospheric***	No
Pulp and paper	Lime kiln	~ 16	Atmospheric***	No
Iron & Steel	COREX smelting reduction process	32 - 35	Atmospheric***	No
	Hot Stove	24 - 28	Atmospheric***	No
	Lime calcining	7.1 – 8.1	Atmospheric***	No
	Sinter plant	3.7 – 4.2	Atmospheric***	No
Aluminium	Aluminium smelter	0.8 – 1.1	Atmospheric***	No
Fertiliser	Coal gasification syngas	750 - 2500	3000 – 6000	Yes*
	Natural gas reforming syngas	300 - 1200	2000 – 3000	Yes*
Natural gas processing	Natural gas processing	Varies, up to 5000	900 – 8200+	Yes, acid gas removal
Bioethanol	Ethanol fermentation	> 85	Atmospheric***	**

* CO_2 from syngas stream is captured for downstream urea production
** Only dehydration and compression required
*** Standard atmospheric pressure is 101.3 kPa, which is close to the average air pressure at sea level. However, atmospheric pressure does vary by location and altitude.

Figure 1 shows that the cost of carbon capture tends to decrease as the CO_2 partial pressure increases in the source flue gas.

Figure 1: Impact of Partial Pressure of CO_2 on Cost of Capture (Kearns, Liu, & Consoli, 2021)

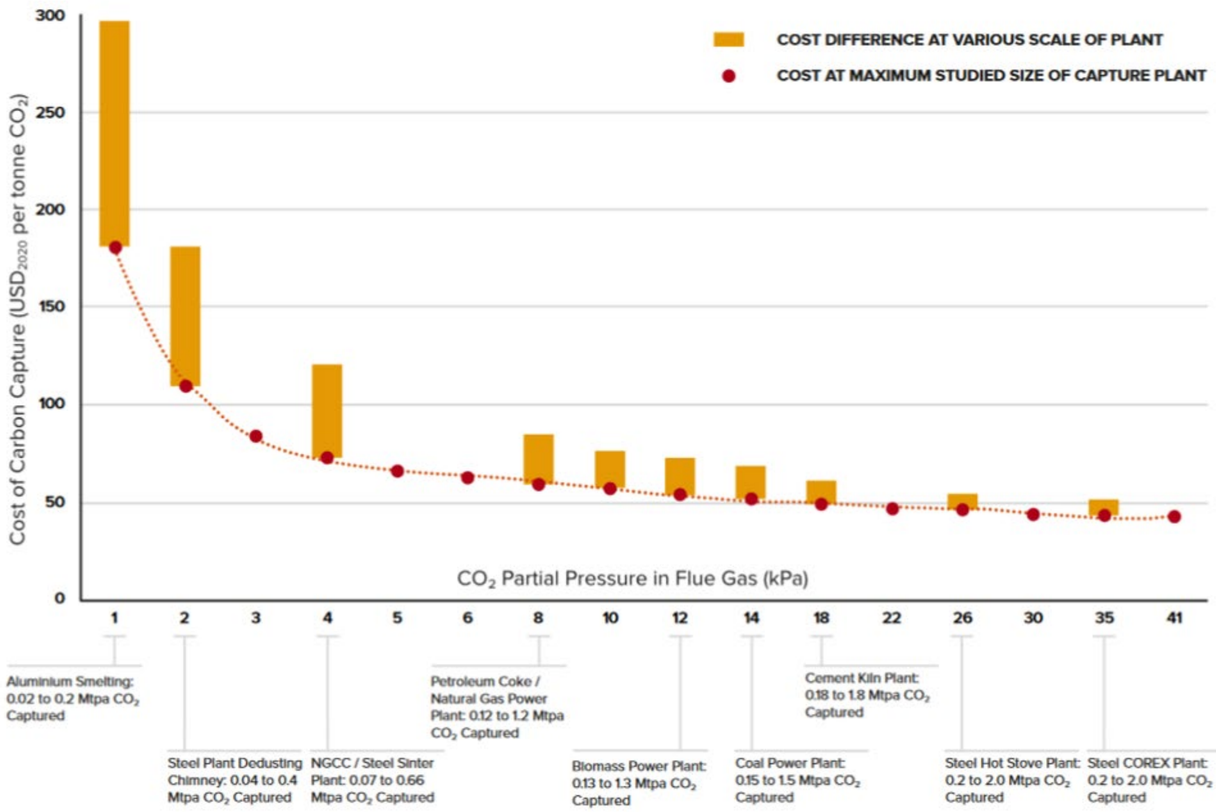
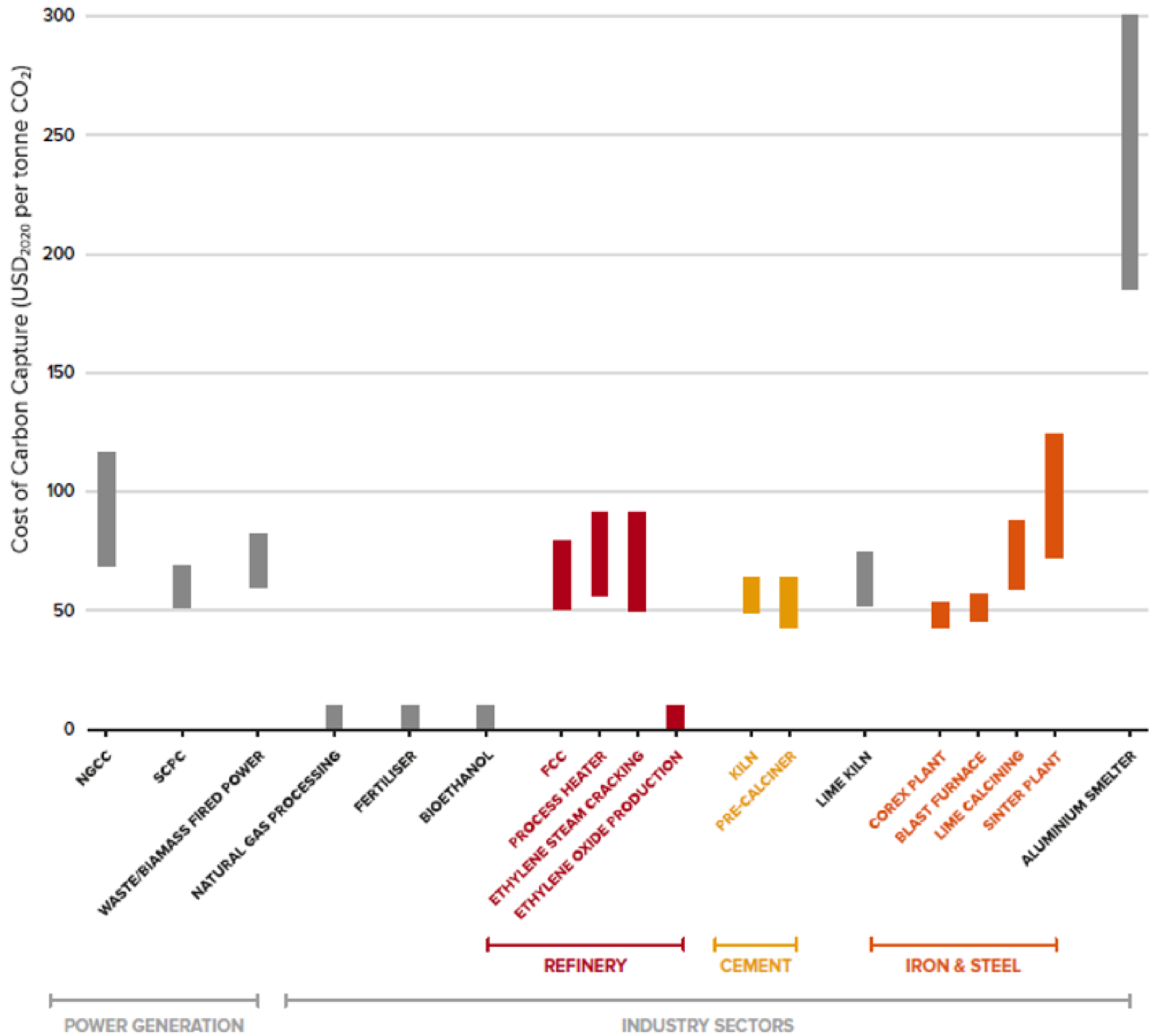


Figure 2 shows the expected costs for various sources of CO_2. As can be seen, natural gas processing, fertilizer manufacturing (SMR), bioethanol and ethylene oxide production have very low cost of capture since the partial pressure of CO_2 for these sources is so high. These sources of CO_2 are likely to be attractive options for carbon capture. Since air has a lower partial pressure of CO_2 than the flue gas from aluminum smelters, direct air capture is expected to have an even higher cost of capture than aluminum smelters.

Figure 2: Costs of Carbon Capture for Various Sources of CO_2 (Kearns, Liu, & Consoli, 2021)



There are many carbon capture projects in various stages of development. Figure 3 show the CCS projects which are either operating or in advanced stages of development as of 2021.

Figure 3: CCS Project in Operation or in Advanced Stages of Development (Global CCS Institute, 2021)

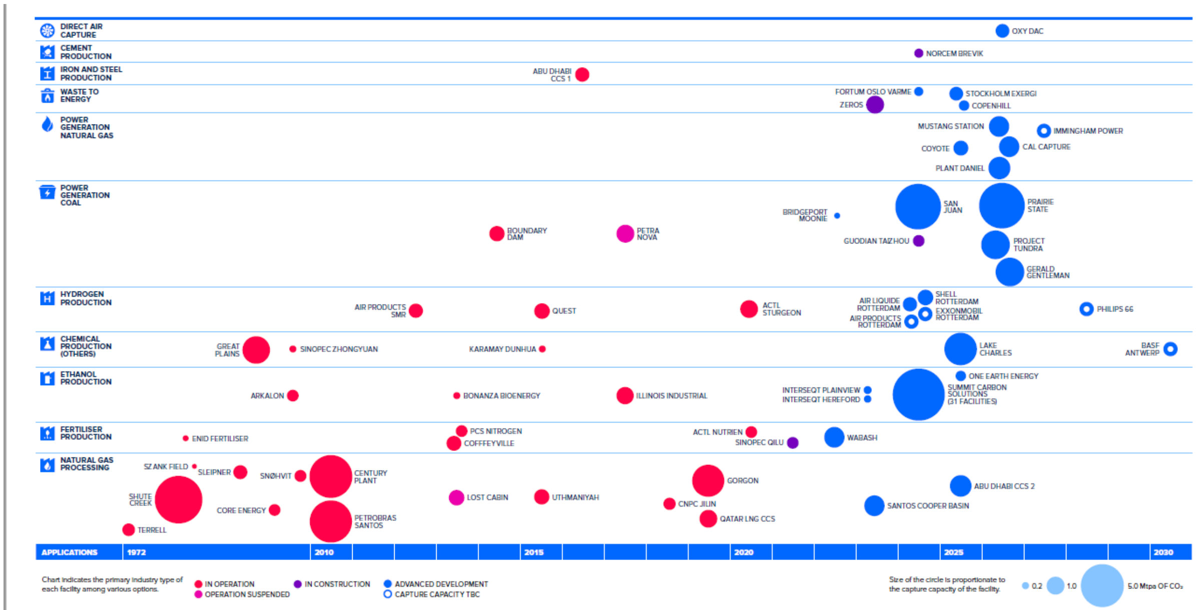


FIGURE 9 CCS PROJECTS BY SECTOR AND SCALE (BY CO_2 CAPTURE CAPACITY) OVER TIME

3.6.4. Natural Gas Processing

A large amount of CO_2 is already being captured from natural gas processing plants. During natural gas processing CO_2 must be removed from the gas. It is often reinjected as an acid gas back into underground reservoirs.

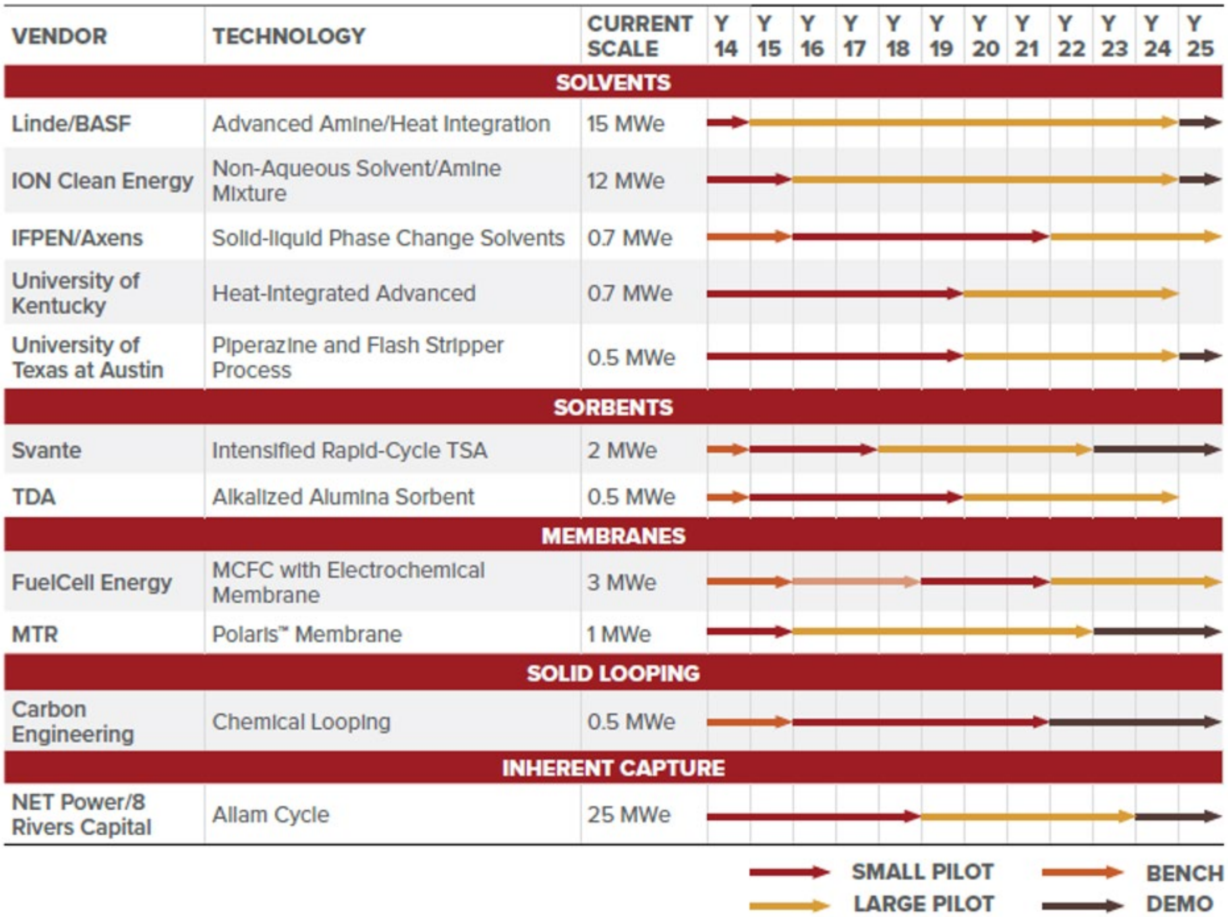
3.6.5. Next Generation Carbon Capture Identified by GCCSI

The Global CCS Institute has also identified several next generation carbon capture technologies:

- Ion Clean Energy's non-aqueous ICE-21 solvent has been selected for a Front-End Engineering Design (FEED) study of retrofitting carbon capture to Nebraska Public Power District's Gerald Gentleman Station;
- Membrane Technology and Research's Polaris™ membrane system has been selected for a FEED study at Basin Electric's Dry Fork Station;
- Mitsubishi Heavy Industries' new KS-21TM solvent has been selected for a FEED study of retrofitting CCS to Prairie State Generating Company's Energy Campus;
- Linde-BASF's lean-rich solvent absorption/regeneration cycle technology has been selected for a FEED study at Southern Company's natural gas-fired power plant;
- The University of Texas's piperazine advanced stripper (PZAS) process has been selected for a FEED study at the Mustang Station of Golden Spread Electric Cooperative; and
- Svante's VeloxoTherm™ has been selected for a FEED study to capture CO_2 from the flue gas of the cement kiln and natural gas fired boiler in a Lafarge Holcim cement production facility (Kearns, Liu, & Consoli, 2021).

Selected next-generation carbon capture technologies are shown in Table 8. This table shows the expected stages of development for each up to 2025.

Table 8: Selected Next-Generation Carbon Capture Technologies (Kearns, Liu, & Consoli, 2021)



This information can be used to help determine the most attractive sources of CO_2 and the most attractive options to capture it.

3.7. Insights, Remaining Gaps and Recommendations

The Jacobs/Suncor report entitled “A Greenhouse Gas Reduction Roadmap for Oil Sands” stated, “In addition to the cost of capture (which is currently higher than the compliance costs in any jurisdiction in the world, including Alberta), there are other barriers to implementation of carbon capture, which include:

- Space constraints (for retrofit facilities);
- Suitable geological sites for CO_2 storage;
- Pipeline access, and costs of the pipeline to transport CO_2 to storage sites; and
- The significant utility needs (steam and/or electricity) for carbon capture that offsets much of the gain from capturing CO_2.”

Carbon capture is a mature technology and has been commercially available for more than fifty years. However, much of that adoption has been to purify feedstocks and fuels. Until recently it had not been used for the expressed purpose of reducing GHG emissions. The advent of regulatory mandates to reduce GHG emissions has spurred interest in developing carbon capture for different sources of CO_2.

"However, current CCS technologies are too expensive to be economically viable at the current cost of avoided CO_2 or captured CO_2" (Suncor, 2012).

Therefore, it is important that the cost for carbon capture be reduced substantially. The cost of carbon capture is dependent upon both the characteristics of the underlying capture technology and the nature of the CO_2 source. An attractive form of carbon capture must have low cost compared to the alternatives and should be able to be adopted so as to lead to large amounts of CO_2 capture. The cost for carbon capture can be reduced and wider adoption of carbon capture can be achieved by pursuing the following important actions:

1) Advances in amines and capture processes which lead to lower costs should be pursued;
2) Second and third generation forms of non-amine carbon capture should be advanced;
3) Learnings from previous carbon capture projects need to be used to reduce the costs of future projects;
4) Situations where carbon capture is a lower cost means to meet emission reduction objectives, compared to alternatives, should be identified and developed;
5) Alberta Innovates could partner with other organizations to jointly work on efforts to advance carbon capture;
6) Lower cost options to use carbon capture in unique situations and ways to eliminate current physical limitations on the use carbon capture should be developed;
7) The use of carbon capture in novel configurations or using carbon capture with novel systems integration in mature industry processes should be developed;
8) Advanced cycles employing carbon capture should be developed;
9) Attractive uses for CO_2 to make other products or fuels should be identified and developed; and
10) Options to optimize carbon capture costs based on capture rates and CO_2 concentration should be explored.

Each of these recommendations will be discussed in more detail below.

3.7.1. Advanced Amines

Amine capture of CO_2 is commercially available and used in the Boundary Dam carbon capture facility to capture approximately 1 million tonnes per year of CO_2. Various entities are testing amines to attempt to find ones with lower energy requirements, lower corrosion characteristics, better operating characteristics and robustness, leading to lower overall costs for CO_2 capture.

Efforts are being made to reduce equipment size and include initiatives to increase flue gas concentration, developing capture media with faster uptake and regeneration kinetics, and developing higher CO_2 capacity capture media. Also, designing systems utilizing lower-cost materials will reduce costs. Improvements in process design and optimization in inter-cooling, lean vapour recompression, split flow arrangement and stripper inter-heating can further drive costs down. In addition, new additives and process design modifications are being developed to lower capture costs.

Developing new amines is important work because there are few commercially available alternatives to capture CO_2 besides amine scrubbing. Therefore, if entities wish to adopt carbon capture in the near-term to comply with regulations, they may have little choice than to build amine scrubbing plants. However, as the Suncor/Jacobs roadmap stated the costs of carbon capture based on these technologies is high. Entities wishing to adopt lower cost forms of carbon capture and perhaps gain a competitive advantage will need to pursue advanced forms of carbon capture.

3.7.2. Next Generation Capture Technologies

If the cost of carbon capture is to decrease materially, then advanced forms of carbon capture which do not rely on liquid amines will need to be developed. These technologies will need to provide lower CAPEX and energy requirements. As described above in Section 3.5.2, EPRI identified many potential advanced carbon capture technologies for the CCPC. As described in Section 3.6.2 EPRI maintains a database containing information and evaluations of novel carbon capture technologies. The first step should be to identify promising advanced carbon capture technologies and help them develop. Papers studies could be completed or EPRI could be asked to identify the most promising carbon capture technologies for desired types of flue gas. Then techno-economic comparisons of the technologies on the same basis should be completed. Then, further engineering and design work, costing and piloting can be completed.

AI identified molten carbonate fuel cells as a promising form of carbon capture. AI conducted prior feasibility studies, and ERA is funding a $38M project to demonstrate this technology. (ERA, Molten Carbonate, 2020b) It would be prudent to follow closely the demonstration of this technology in Alberta and other parts of the world. It would also be prudent to watch the development of other advanced forms of CCS. For example, ERA has provided funding for a 30 t/d demonstration of the Inventys (now Svante) carbon capture system in Alberta. (ERA, Veloxotherm, 2020d) The results of this project and other CCS projects should be reviewed closely and communicated. Further, economic analysis, engineering and cost estimation of commercial scale facilities based on these technologies could be considered if the results of the demonstration facilities are promising.

3.7.3. Knowledge Sharing

Increased knowledge sharing regarding projects deploying carbon capture is needed. Pembina Institute (Kilpatrick, Goehner, Angen, McCulloch, & Kenyon, 2014) and MK Jaccard and Associates (Peters, Sharp, Bataille, Groves, & Melton, 2011) in their reports described learning rate assumptions when forecasting the decreasing cost to capture CO_2. Unfortunately, very few carbon capture plants have been built and therefore carbon capture is not far down the learning curve. Shell has been providing tours and information sessions regarding its Shell Quest project (IEAGHG, 2019). The CCS Knowledge Centre exists to help pass on learnings from the Boundary Dam CCS project to new projects proposing to adopt CCS (CCS Knowledge Centre, 2021). The Shand Carbon Capture Test Facility is testing various novel amine solvents (SaskPower, 2021a). The US Government is also putting significant effort towards technologies that reduce the cost of capture. Industry members and consortia have insights into the constraints and opportunities to deploy carbon capture at their sites. Alberta Innovates and its subsidiaries are ideally positioned to leverage these resources to close some of the gaps related to carbon capture which are specific to the needs of Alberta's industries. Further effort should be made to pass the learnings from existing carbon capture plants on to those proposing to build carbon capture plants. These learnings would be based on actual operating experience, rework required, and proposed design changes identified after the fact, etc. Alberta Innovates could work with all of these organizations to communicate the services they offer to advance carbon capture.

Carbon capture cannot develop if insights regarding the optimizing of its design, implementation and operation are not shared within the market. Innovation happens when people share ideas, knowledge and opportunities. If carbon capture is to develop at a pace that global decarbonization targets require, then knowledge sharing regarding carbon capture advances needs to increase. Carbon capture can be advanced by sharing knowledge in the following ways:

- Knowledge about promising new advances and about ideas which have not worked well elsewhere should be shared. This will help focus development on promising opportunities;
- Knowledge about how carbon capture is likely to be adopted widely should be shared to focus development opportunities;
- The issues with carbon capture should be shared to spur the development of novel solutions;
- Knowledge about carbon capture should be collected and summarized and made publicly available, on the Alberta Innovate's website;
- Knowledge about how to design carbon capture systems better based on actual experience should be shared;
- The results of detailed techno-economic analysis need to be shared widely;
- A library of good public reports on carbon capture relevant to opportunities in Alberta should be created;
- Knowledge about how to complete high quality detailed techno-economic and feasibility studies of carbon capture should be shared;
- People with knowledge of carbon capture systems should apply this knowledge to review technologies, to recommend technologies for further study and to help people develop their technologies; and
- More collaboration between numerous parties to share information, support research and technology development and work on joint studies and projects should be fostered.

3.7.4. Carbon Capture as Least Cost Option Should be Identified

Study work to advance carbon capture should be focused on the applications that are most likely to be widely adopted. Table 1 indicates the major sources of CO_2 in Alberta and thus indicates where the largest potential carbon capture opportunities may be in the province. Study work needs to be completed to determine for forecasted carbon prices and for given GHG emission intensity mandates, what carbon capture technologies are likely to address the majority of carbon capture opportunities. That is, based on the specific sources of GHG emissions at facilities, an assessment should be made to determine how much of it can likely be captured economically. These applications of carbon capture may be on existing or future GHG emissions.

Desired realistic target costs of carbon capture technologies should be developed for specific types of GHG emission sources based on the greatest opportunities for reductions for lowest costs relative to current and future carbon pricing mechanisms.

Some opportunities to use carbon capture may be imminent and others may require other developments and infrastructure to come to fruition. Some forms of CO_2 emissions, such as coal plants, are sunset industries and perhaps carbon capture for these types of plants should no longer be studied. In Alberta, Capital Power indicated that their last coal-fired power plants would be retrofitted to operate on natural gas as early as 2023, seven years before the Federal mandate (CPC, 2021).

Opportunities to adopt carbon capture which are likely to lead to large decreases in GHG emissions should be identified. Carbon capture technologies best suited for use in the specific industrial opportunities identified should then be chosen for development.

3.7.5. Advanced CO_2 Capture Technologies Partnerships

Alberta Innovates and subsidiaries (InnoTech and C-FER) could partner with other organizations who are studying and developing carbon capture to pool resources and expertise. The following is a short list of entities working to lower the cost of new carbon capture technologies.

- Realise CCUS (Realise CCUS, 2021)
- C2ES – Centre for Climate and Energy Solutions (C2ES, 2021)
- National Energy Technology Laboratory (NETL, 2021c)
- NRCAN (NRCAN, 2021)
- Carbon Management Canada – C4 (CMC, 2021)
- Equinor (equinor, 2021)
- InnoTech's Alberta Carbon Conversion Technology Centre (ACCTC)
- CO2 Capture Project (CCP, 2021)
- Oil and Gas Climate Initiative (OGCI, 2021)
- Global CCS Institute (GCCSI, 2021)
- IEA (IEA, 2021b)
- Electric Power Research Institute (EPRI, 2021)
- Shand Carbon Capture Test Facility (SaskPower, 2021a)
- National Carbon Capture Center (US DOE, 2021e)

3.7.6. Lower Cost Capture Technologies for Specific Applications

Many carbon capture ideas need to be configured to provide a complete process for specific applications. There are numerous equipment, process flow and heat integration and recovery options which need to be optimized to create an actual process for a specific application. Some carbon capture technologies may have more or less promise depending upon the application and desired outcomes of the project. The carbon capture solutions needed for cement may differ from those needed for OTSG or cycling natural gas combined cycles.

The characteristics of the CO_2 source, such as CO_2 concentration, pressure, temperature, fly ash concentration and other gaseous components, may make some forms of carbon capture technologies more attractive than others. Likewise, the operational flexibility of the capture system, the additional commodities it may provide, its footprint, the desired end state of the CO_2, its suitability to energy storage, its capture rate and capture purity make some capture systems more attractive in certain situations. Carbon capture systems which can be made more compact may be more amenable to facilities where there are space constraints. Low carbon fuels supplied by processes employing carbon capture may mitigate these space constraints as well. Additionally, low carbon fuels might be used to displace bulk natural gas for general consumption. For example, some forms of hydrogen need to be compressed or liquefied for use. Technologies incorporating carbon capture which optimize the cost of low carbon fuels for specific applications will therefore be attractive in the future as low carbon fuels increase in popularity and availability. Additional considerations for choosing a carbon capture technology include existing process conditions such as temperature, pressure, available heat, level of purity of inputs, variability of CO_2 supply, proximity to carbon sinks, CO_2 stream purity needs, process chemical availability, and others. Therefore, developing carbon capture processes which overcome the limitations of existing forms of carbon capture or are better fits for targeted carbon capture opportunities may be warranted.

3.7.7. Advanced Clean Power Cycles

The CCPC studied numerous advanced cycles for producing cleaner power including hydrogen as a fuel. The CCPC identified that amine scrubbing or molten carbonate fuel cells may be a more economical way to lower GHG emissions from gas-fired generation than using H_2. Further work should be completed to assess the costs and characteristics of advanced power cycles and other clean gas-fired dispatchable options. Additionally, advanced cycles producing clean hydrogen with carbon capture should also continue to be developed. It should be noted that if these power generation methods are used in a load-following capacity, the capture equipment will need to be able to operate efficiently with a variable input, and this may have implications as to which technologies may be best suited for this application.

3.7.8. Novel Configurations of Carbon Capture

Novel carbon capture configurations should be developed to allow carbon capture to be used optimally in unique situations. Conventional amine scrubbing is typically designed for baseload application. In the future, as the portion of intermittent and variable output forms of renewables are added to the power systems, natural gas forms of power generation will still be needed to provide capacity. However, these natural gas forms of generation may operate at part output, may dispatch off and ramp up and down more often. Some forms of CO_2 are more dilute than others or may have unique characteristics such as contaminants, higher temperatures and/or pressures. Some forms carbon capture may be more economical for one type of flue gas than others. Developing novel technologies in novel configurations may help reduce the cost to capture these forms of CO_2. For example, CO_2 concentration can be increased by recycling CO_2 or by staging two types of carbon capture technologies.

Novel IGCC and ISCG configuration should also continue to be studied. The CCPC showed that novel technologies and configurations of these technologies may lower the cost of IGCC and ISCG significantly.

In the future, novel carbon capture systems, such as molten carbonate fuel cells, which can provide additional benefits such as hydrogen, water and power may be attractive. Also, carbon capture may be integrated with energy storage to better allow for load following and to provide other power system services (as with SES's cryogenic system) or to allow for baseload operation of carbon capture systems should be evaluated further.

There is also a significant interest in electrifying heat sources in industry to displace the use of fossil fuels. There may be ways to integrate power generation with carbon capture into industry systems cost effectively, although carbon life cycle assessments will likely be required to determine full carbon footprint as the primary electricity production method in Alberta is through natural gas-fired turbines.

There are ways to integrate power generation into SMRs or ATRs to produce hydrogen. Given the premium put on lowering GHG emissions and the system issues associated with the energy transition to cleaner fuels and energy, opportunities to design novel carbon capture systems which provide other commodities and facilitate the provision of other services or allow for carbon capture in unique situations should be assessed and the attractive ones should be developed. Air Products recently announced its Blue Hydrogen Hub initiative in the Alberta Industrial Heartland which comprises an ATR plus carbon capture facility with 100 per cent hydrogen-fuelled power generation to create low carbon hydrogen and a concentrated CO_2 source for pipelining via the Alberta Carbon Trunk Line (Air Products, 2021). Emissions Reduction Alberta has contributed funding to this initiative (CBC, 2021).

3.7.9. CO_2 Utilization

CO_2 capture systems which are amenable to making low carbon fuels, other products or commodities could be considered for further study.

3.7.10. Partial Capture and Lower Purity

There may be lower cost ways to capture CO_2 and deliver it at lower purities. The trade-offs between the costs to purify CO_2 and the requirements of various storage, EOR and utilization processes should be studied. Further, low carbon fuels may not need to contain very low concentrations of CO_2. Carbon capture technologies which can meet the CO_2 purity requirements of low carbon fuel options employing hydrogen or syngas could be identified and studied in more detail.

Further, the cost of carbon capture is related to the capture rate. As the capture rate increases the marginal cost of capture increases driving up the average cost of capture. (Du, Gao, Rochelle, & Bhown, 2021) High capture rates may not be required to economically meet regulatory compliance requirements. For instance, the Shell Quest project only captures about 80 per cent of the CO_2 in the steam entering the capture system (IEAGHG, 2019). Lower cost lower capture rate carbon capture technologies may be attractive in these situations. These types of carbon capture systems could be studied in more detail, to better understand the trade-offs between GHG capture efficiency and cost efficiency.

4. Conclusion

Alberta Innovates, InnoTech Alberta, C-FER and ERA have completed numerous projects which have spurred the development of carbon capture. These organizations are well positioned to implement the recommendations listed above. Their continued support of carbon capture will help it become more widely used to reduced GHG emissions in Alberta and abroad.

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