Energy Solutions Center

Carbon Capture & Utilization (CCU) Training Manual for ESC Members

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Cogeneration and Energy Management Engineering Inc.

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1/ CONCLUSIONS

(a) There are over 50 prominent companies worldwide which specialize (or are starting to focus on) Carbon Capture, Utilization, & Storage (CCUS).

(b) The technologies for CCUS activities are mature; ready for commercial deployment; and can decarbonize existing infrastructure, with minimal changes to business operations and industrial processes, since CO_2 is being extracted “from the back end”.

(c) There are eight (8) specific technology methods to capture CO_2 from flue gases produced by the combustion of natural gas. Of these eight (8) technologies, chemical absorption is the most mature, by far. The amine-based solvent, which is at the heart of the chemical absorption process, is able to separate CO_2 from the flue gas mixture and bind the CO_2 to itself. The CO_2 is then later released from the amine, after it is heated.

(d) There are several chemical absorption OEMs which produce both conventional amine systems and compact solutions. These compact solutions feature rotating packed bed technology, and take up much less space, and are therefore more CAPEX efficient.

(e) The Levelized Cost of Carbon Abatement (LCCA) for conventional amine systems is roughly 60-70 USD/tonne (80-100 CAD/tonne). The compact technology will drop this LCCA to roughly 45-50 USD/tonne.

(f) This LCCA must be compared with the carbon tax (Canada) or the tax credit (U.S.) to determine if adding CCU is in the customer’s long term financial interest. Clearly, if the LCCA is lower then the carbon tax, or the tax credit, then it is in the client’s interest to investigate CCU.

(g) The biggest challenge, by far, with CO_2 is - what to do with the CO_2, once it is captured. Do we utilize it, or do we store it?

(h) Given that there is a shortage of CO_2 presently throughout North America, post-COVID, the production of food and beverage grade CO_2 and the production of fuels from the CO_2 have the highest TRL (~7-9). However, mineralization of captured CO_2 is presently the only acceptable utilization method, which results in the complete “destruction of CO_2”.

(i) Of those OEMs which can provide technology which both capture and utilize CO_2, the most active and the most advanced OEMs produce methane or chemicals from the captured CO_2.

(j) Given that the concentration of CO_2 is highest in flue gases from boilers (~8-12% by volume), large continuous-duty water tube boilers are the obvious place to start introducing CCU. The concentration of CO_2 in the flue gases from ICEs, can be less than that of boilers (~7-10%). Similarly, the concentration of CO_2 is lowest in combustion gas turbines (~4-5%), given that a combustion gas turbine is an air-cooled machine and uses much more air than a boiler or an internal combustion engine.

(k) In Canada, a rising carbon tax (**$50/tonne** CO_2 in 2022 to **$170/tonne** CO_2 in 2030), combined with a pending 50% of CAPEX CCUS tax credit, makes CCUS a viable solution for many medium-to-large consumers of fossil fuels.

(l) In Canada, limited regulations pertaining to the storage and utilization of CO_2 however, are slowing the adoption of this key decarbonization technology.

(m) In the U.S., the newly adopted Inflation Reduction Act (along with the expanded **45Q tax credit**, which is direct pay eligible), provides a significant financial incentive to consumers of fossil fuels to adopt CCUS technologies. Assuming a commissioning date of 2026 (when the incentives reach their maximum value), the following applies:

(i) For organizations that implement Carbon Capture systems and **STORE** the captured CO_2, a tax credit of **$85/tonne** CO_2 is available for the first **12 years** of the project lifetime.

(ii) For organizations that implement Carbon Capture systems and **UTILIZE** the captured CO_2, a tax credit of **$60/tonne** CO_2 is available for the first **12 years** of the project lifetime.

(n) We recommend LDC's target large volume customers who are now consuming between 60,000 and 2.4 million mmBtu (2 million – 85 million m^3, 75 million – 300 million ft^3, 1.6 million – 24 million therms) of natural gas annually. This is equivalent being responsible for roughly 3,000 to 120,000 tonnes per year of CO_2 emissions. Modular, pre-engineered, carbon capture technology is being designed in the 10 tonne/day to 100 tonne/day range.

2/ BACKGROUND & INTRODUCTION

2.1 Acronyms

ASU	Air Separation Unit
CCUS	Carbon Capture and Utilization
CLC	Chemical Looping Combustion
CPU	Compression Purification Unit
DAC	Direct Air Capture
DAC	Department of Energy
GTG	Gas Turbine Generator
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
OEM	Original Equipment Manufacturer
PBR-CLC	Packed Bed Reactor Chemical Looping Combustion
PCC	Precipitated Calcium Carbonate
PFD	Process Flow Diagram
RNG	Renewable Natural Gas

2.2 Conversions

278 kW.h = 1 GJ

293 kW.h = 1 mmBtu

1 mmBtu = 10 therms

0.91 tonnes = 1 US ton

1,000 tonnes = 1 kilotonne (kt)

1,000 kilotonnes = 1 megatonne (Mt)

2.3 Emission Factors

FUEL	UNIT	VALUE
Natural Gas	kg/mmBtu	53
Coal	kg/mmBtu	98
Heavy Fuel Oil (#6)	kg/mmBtu	75
Gasoline	kg/mmBtu	67
Diesel	kg/mmBtu	74
Propane	kg/mmBtu	63

2.4 Introduction

(a) Whether CEM is designing thermal power systems based on fired boilers or combustion GTGs or ICEs, we are (up until now) burning almost exclusively natural gas.

(b) The underlying fundamental equation in all CEM projects is therefore:

$$CH_4 + 2\ O_2 \Rightarrow \text{Energy (Heat)} + CO_2 + 2\ H_2O$$

(c) If CEM is going to do our part as licensed professional engineers to reduce CO_2 emissions, there are essentially only two (2) choices:

(i) Capture CO_2

(ii) Utilize clean fuels

(d) The challenge going forward is that Canada, and more broadly in North America, has a very plentiful supply of natural gas. For example, note the following:

(i) When Martin Lensink left Union Gas in 1989, there was 35 years of natural gas (roughly) available, based on proven reserves, according to the National Energy Board.

(ii) In late 2000, just before Martin Lensink left Toromont Energy and started CEM, there was 8-10 years' worth of natural gas available in Canada.

(iii) Now, with fracking, there is over 150 years' worth of natural gas available in the ground, based on proven reserves (CGA).

(e) As a result of this serious oversupply, prices have fallen significantly.

(f) Moreover, the natural gas system (specifically in Ontario) has 4-5 times the capacity (in MW) as the electricity system.

(g) As the cost of carbon goes from (for example) \$50/tonne to \$170/tonne (in Canada) and beyond, can it continue to burn natural gas and simply retrofit the "back end" of the systems designed in the past with CCUS technology?

(h) With the geology to support sequestration activities, the United States has potential to be a leader in CCUS projects in the short and medium term.

(i) The purpose of this report, therefore, is to assess where CCUS technology can be installed in Canada and the United States, and specifically:

(i) Is CCUS technically feasible?

(ii) Is CCUS financially feasible, based on future cost of carbon and/or tax incentives?

(iii) Is CCUS implementable?

2.5 CO_2 Produced by the Combustion of Natural Gas in GTGs, Boilers, and ICEs

(a) Towards understanding how much CO_2 is produced by the Natural Gas systems CEM has designed over the past 10+ years, please note the broad overview below.

PRIME MOVER	CAPACITY	CO_2 EMISSIONS			CO_2 CONCENTRATION
		100% LOAD	75% LOAD	50% LOAD	
		TONNE/HR	TONNE/HR	TONNE/HR	%, BY VOLUME
ICE	2.0 MW_e	0.93	0.72	0.51	7-10
GTG	3.5 MW_e	2.46	1.99	1.59	4-5
	4.6 MW_e	3.06	2.48	2.03	
	5.7 MW_e	3.52	2.88	2.32	
	6.3 MW_e	3.83	3.07	2.46	
	8.0 MW_e	4.64	3.79	3.03	
	15.0 MW_e	9.11	7.40	5.93	
	21.7 MW_e	11.44	9.33	7.88	
Boiler	82.7 kpph	5.31	3.96	2.64	8-12

(b) Note that the above listed CO_2 concentration ranges are **by volume** and not by mass. CO_2 concentration therefore changes depending on the characteristics of combustion (i.e., excess air, reduced nitrogen from partial oxy firing, flue gas recirculation).

(c) Relevant equations for each of the prime movers are listed below:

PRIME MOVER	FUEL FLOW (MMBTU/HR)		HHV/LHV CONVERSION		ENGINE POWER (BHP)		EMISSION FACTOR (KG/MMBTU)		CO_2 EMISSIONS (KG/HR)
GTG	A	x	1.1	x	-	x	53	=	58 x A
ICE	B	x	-	x	-	x		=	53 x B
BOILER	C (PER BHP)	x	1.1	x	D	x		=	58 x C x D

2.6 Low CAPEX Option to Reduce CO_2

(a) Based on the table in Section 2.2, the summary table below shows the range of challenges faced by our previous clients, going forward.

PRIME MOVER	CAPACITY (MW_E)	OPERATION (HOURS/YEAR)	CO_2 FOOTPRINT (TONNES/YEAR)
ICE	2.0	1,000	900
	2.0	8,000	7,400
GTG	5.7	8,500	29,900*
	15.0	8,300	75,600*

** Excludes fuel use by duct burner*

The challenge before us is, how do we respond to our previous clients? Should they come to us and say "now what do we do"?

(b) Certainly, the most obvious strategy going forward is to make the prime mover "last on-first off", rather than "first on-last off" (i.e., use the prime mover only for peak shaving and load management, and not in the continuous-duty mode).

(c) However, several of our customers have made 10-year commitments to displace significant amounts of purchased power.

(d) Reducing the operating hours of CO_2 emitting equipment is only a partial measure and is not viable for all emitters.

(e) From a resiliency perspective, it may be preferable to maintain on-site electricity generation to "take advantage" of two (2) energy distribution networks (i.e., the electric grid **and** the natural gas grid).

2.7 Removal of CO_2 Prior to Combustion

(a) To reduce Scope 1 emissions (from combustion of fossil fuels on-site), organizations can instead look at fuel replacement in their existing equipment.

(b) For some drop-in fuel replacements, the emissions associated with that fuel are simply shifted up-stream and would count as Scope 2 emissions for the company ultimately using that fuel (e.g., for fuels that require electricity to be produced, such as Green Hydrogen).

(c) For natural gas systems, there are two (2) primary gaseous drop-in fuel replacements (that are not RNG): hydrogen and syngas.

(d) Syngas is typically combusted "as-is" without front-end carbon capture (i.e., CO_2 can be captured at the stack instead).

(e) Hydrogen production can feature carbon capture processes to reduce the CO_2 emissions attributable to production of hydrogen that utilizes fossil fuels (this is termed Blue Hydrogen).

2.7.1 Hydrogen Production

2.7.1.1 Steam Methane Reforming with Carbon Capture

(a) Process

  (i) In the most common pathway, methane reacts with steam (which is both a reactant and an energy source) to produce hydrogen and carbon monoxide.

  (ii) Carbon monoxide reacts further with the steam to produce carbon dioxide and additional hydrogen.

  - This is termed "**grey**" hydrogen.

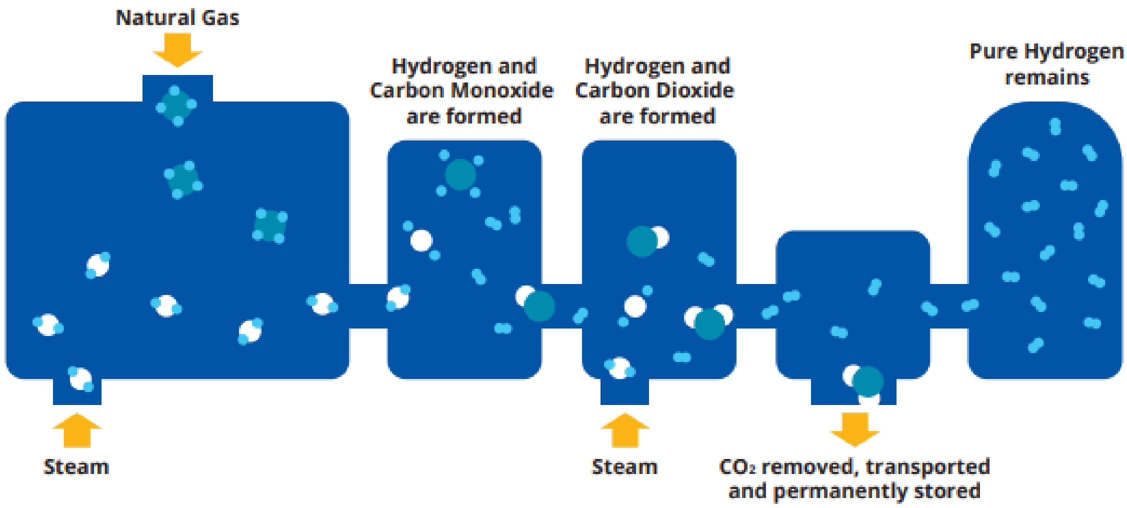
  (iii) Sources of methane include natural gas and pre-formed propane, butane, or other larger hydrocarbons.

  (iv) The addition of a carbon capture unit downstream of the steam methane reformation process reduces the CO_2 emissions of the process by up to 90%.

  - This is termed "**blue**" hydrogen.

(b) TRL: 7-9

(c) PFD:



Source: ATCO Gas ([infographic-hydrogen-types (atco.com)])

(d) OEMs:

OEM*	LOCATION	WEBSITE
Xebec/Hygear	Canada/The Netherlands	[Xebec, The Renewable Gas Company (xebecinc.com)]

***This is one (1) of the few OEMs that offers pre-built, containerized solutions. Otherwise, this type of solution is implemented by an Engineering, Procurement, and Construction (EPC) firm which provides custom equipment and design services.**

(e) Project Examples

(i) Quest Canada
- Operational
- Captures 3,000 tpd amounting to 43% of emissions
- Located in Alberta, Canada

(ii) Nutrien
- Operational
- Captures 500 tpd, amounting to 29% of emissions
- Located in Alberta, Canada

(iii) Tayras Hydrocracking
- Turkey
- 2 Hy.Gen 150, capturing 4 tpd
- Process

(iv) Saint-Gobain Glass Manufacturing
- Spain
- 2 Hy.Gen 50, capturing 1.5 tpd
- Process

(v) Walmart/Plug Power
- United States
- 1 Hy.Gen 50, capturing 0.7 tpd
- Fuel Cells

2.7.1.2 Methane Pyrolysis

(a) Process

(i) Methane is reformed in the absence of oxygen to produce solid carbon (often termed "carbon black") and hydrogen.

(ii) Carbon black is often used in manufacturing (e.g., tire production, battery production, industrial catalysts) as a high-surface area solid. Graphite is also one potential carbon black by-product from this process.

(iii) This is termed "**teal**" hydrogen, as it is slightly "**greener**" than "**blue**" hydrogen

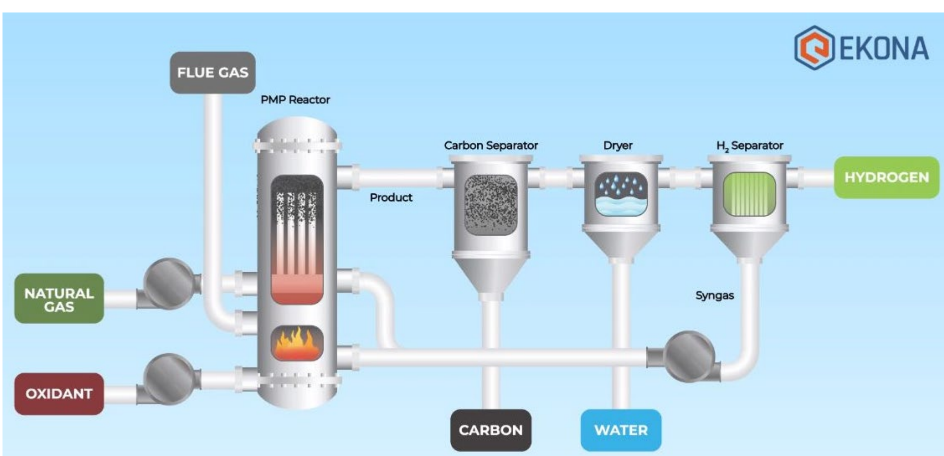
(iv) More carbon is captured using this process compared to "**blue**" hydrogen (i.e., higher capture efficiency since the carbon is a solid)

(v) This technology can use either electricity (termed plasma or microwave decomposition of natural gas) or natural gas (termed thermal decomposition of natural gas) for the pyrolysis reaction.

(vi) The methane decomposition process requires high temperatures within the reactors (1470+ ˚F).

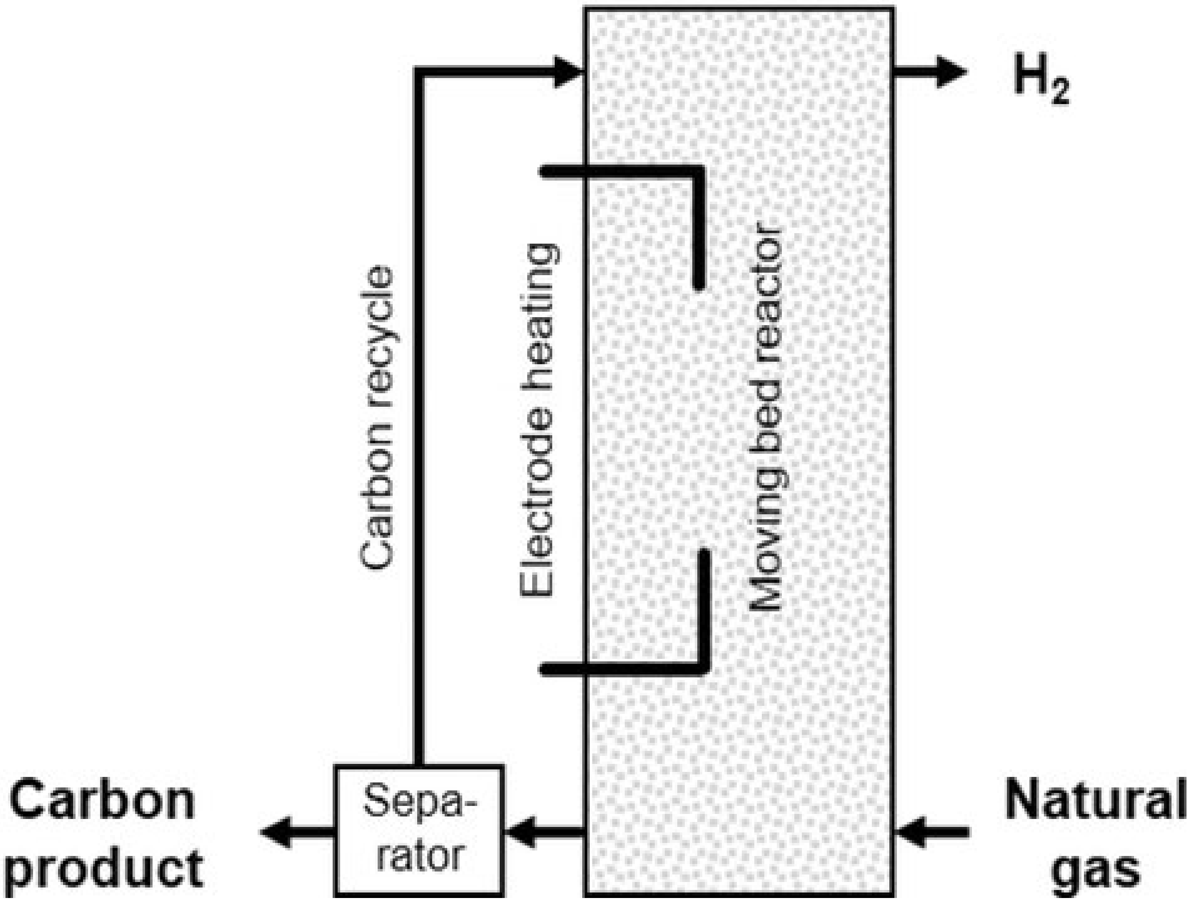
(b) TRL: 5-7

(c) PFD:



Operating parameters

Process temperatures	1000 - 1400 °C
Natural gas feed	10 m^3 h^{-1} (NTP)



Source: [State of the Art of Hydrogen Production via Pyrolysis of Natural Gas - Schneider - 2020 - ChemBioEng Reviews - Wiley Online Library]

(d) OEMs

OEM	LOCATION	WEBSITE
Ekona	Canada	Home | Ekona Power Inc.
Monolith	United States	Monolith (monolith-corp.com)
Hycamite	Finland	Net Zero & Sustainable Energy Production Solution | Hycamite
CZero	United States	C-Zero | Decarbonizing Natural Gas (czero.energy)
HazerGroup	Australia	hazergroup.com.au | Commercialising the Hazer Process
Susteon	United States	Climate Impact Technology Innovations - Susteon Inc.
Nu:Ionic	Canada	Nu:ionic (nuionic.com)
Syzygy Plasmonics	United States	Syzygy Plasmonics
New Wave Hydrogen	Canada/United States	Home - New Wave Hydrogen Inc (newwaveh2.com)
HiiRoc	United Kingdom	Hiiroc

(e) Project Examples

(i) Monolith, Olive Creek Plant 1

- Features a plasma torch system
- Focused on producing carbon black, not hydrogen
- Carbon black production of roughly 14,000 tonnes per year
- The hydrogen produced at this site is utilized to produce ammonia for local applications

(ii) Hazer Group

- Utilizes a Fluidized Bed Reactor (FBR) with an iron catalyst.
- Targeting graphite production with hydrogen as a by-product.
- Approximately 100 tonnes of hydrogen per year will be produced at the Commercial Demonstration Plant (CDP) which was commissioned in 2022.
- The CDP project uses biogas as a feedstock, opposed to natural gas.

(iii) Ekona

- A pilot-scale Pulsed-Methane Pyrolysis (PMP) system, capable of 200 kg of hydrogen production per day is expected to be in service by 2023.
- A follow-up expansion of this pilot is expected to increase hydrogen production to 1 tonne per day once the technology is proven at the pilot scale.

3/ METHODS TO CAPTURE CO_2

3.1 Direct Air Capture (DAC)

3.1.1 Process Description

(a) As the name implies, direct air capture (DAC) involves capturing CO_2 from air that has been taken directly from the atmosphere at low concentrations ~400 ppm.

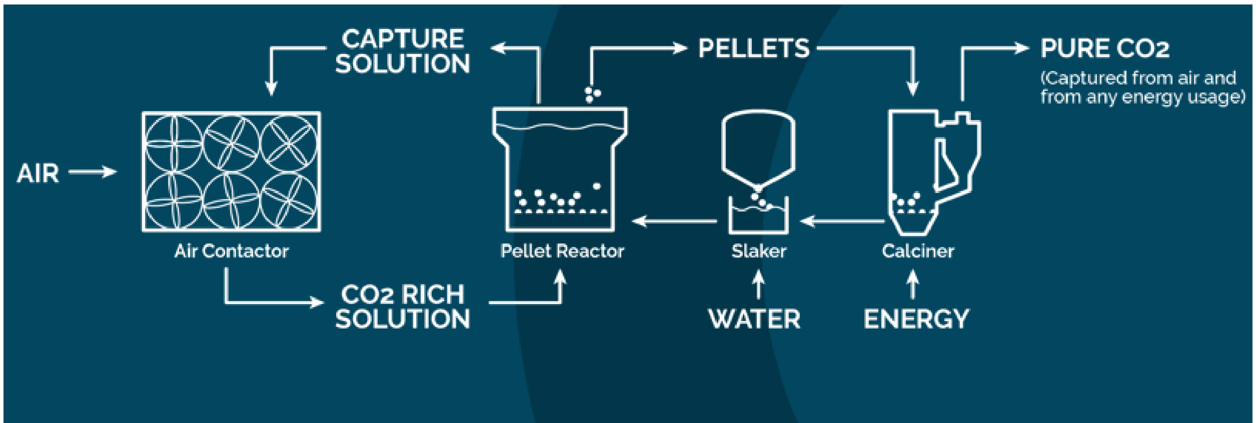
(b) This method is quite different from the eight subsequently listed technologies which typically rely on capturing CO_2 from a **single point** (i.e., point source) at moderate to high concentrations of CO_2.

(c) Point source capture being a method that captures CO_2 not from atmospheric air but rather from flue gases.

(d) Many DAC technologies employ the same capture capture methods listed below (such as use of an amine solvent or a solid adsorbent).

(e) TRL: 5-8

(f) PFD:



CE's Direct Air Capture process, showing the major unit operations - air contactor, pellet reactor, slaker, and calciner - which collectively capture, purify, and compress atmospheric CO_2

3.1.2 OEMs

OEM	LOCATION	WEBSITE
Carbon Engineering	Canada	Carbon Engineering | Direct Air Capture of CO2 | Home
Climeworks	Switzerland	Achieve net zero targets with Climeworks direct air capture
Noya	United States	Noya | Capture CO_2
Global Thermostat	United States	www.globalthermostat.com
Blue Planet	United States	www.blueplanetsystems.com/
Neustark	Switzerland	HOME | neustark
Infinitree	United States	Technology — Infinitree LLC
Greencap Solutions	Norway	Greencap Solutions (greencap-solutions.com)
Prometheus Fuels	United States	Home (prometheusfuels.com)

3.1.3 Existing Project (Climeworks) – DAC Commercial Plant

(a) Commissioned in 2018, this plant is located in Troia, Apulia, Italy.

(b) This plant was apart of the Horizon 2020 research project Store & Go.

(c) With three (3) Climeworks DAC collectors, the plant will be able to filter up to 150 tons of CO_2 from ambient air each year.

(d) At the same time an alkaline electrolyser (1.2 MW) generates 240 m^3/hr of renewable hydrogen.

(e) This is achieved by making use of excess on-site photovoltaic energy.

(f) Once captured, the CO_2 and renewable hydrogen are then catalytically methanated (this process is also called Power-to-Gas) in modular reactors by a French company called ATMOSTAT. This methane is subsequently liquified and used to fuel natural gas lorries.

3.2 Chemical Absorption

3.2.1 Process Description

(a) Based on the reaction between CO_2 and a chemical solvent

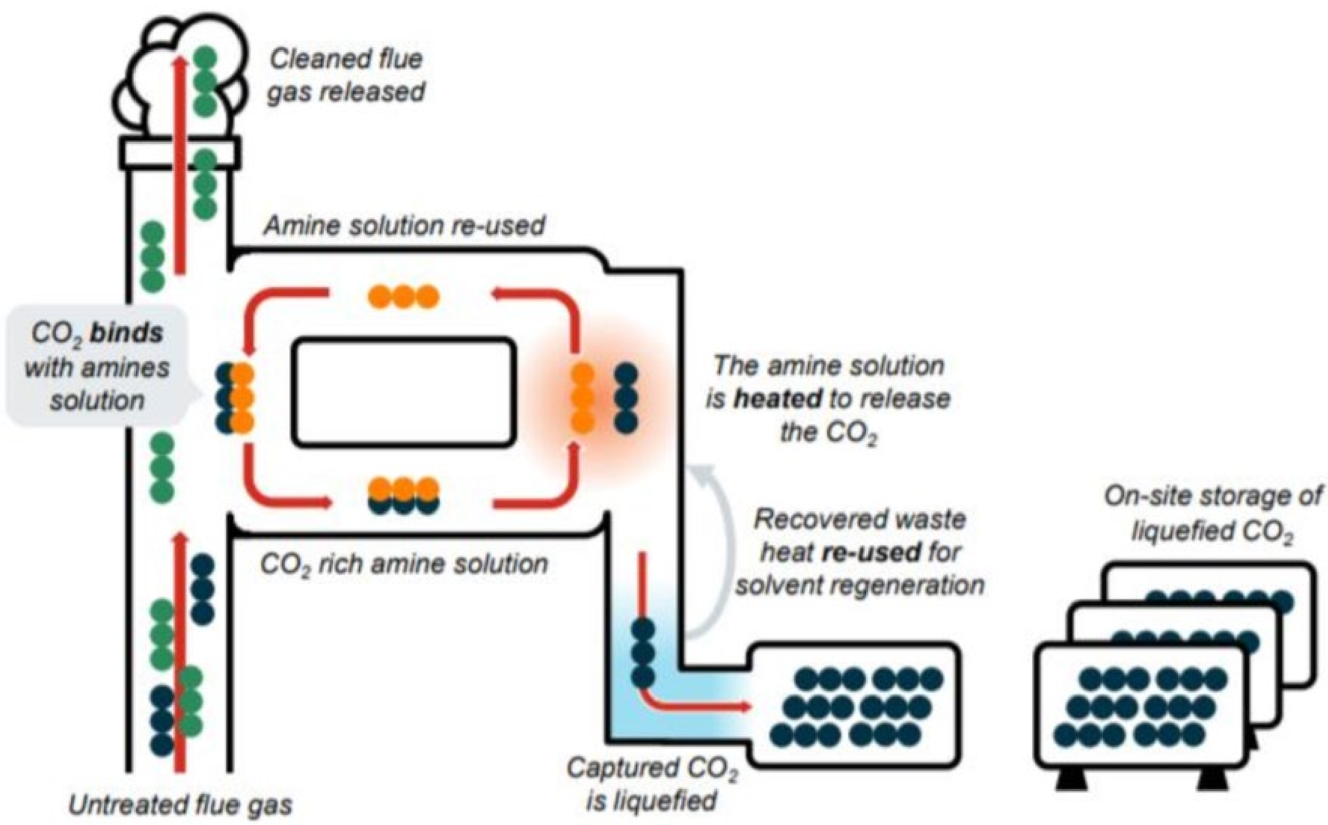
(b) Most advanced CO_2 capture methods use amine-based solvents.

(c) Chemical absorption has been in use for decades for small and large-scale projects worldwide in power generation, fuel transformation and industrial processes.

(d) TRL: 7-9

(e) PFD:

Example (from Aker Carbon Capture):

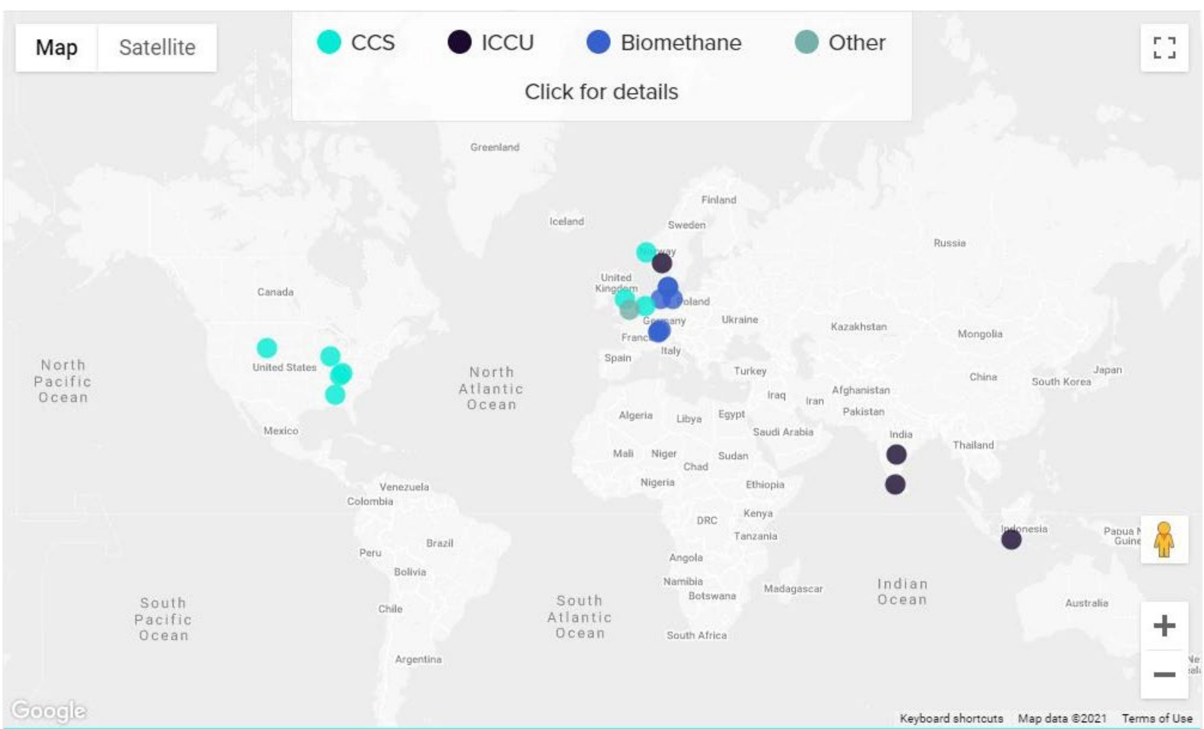


3.2.2 OEMs

OEM	LOCATION	WEBSITE
Carbon Engineering	Canada	www.carbonengineering.com
Baker Hughes	United States	Carbon Capture | Baker Hughes Carbon Capture
Aker Carbon Capture	Norway	www.akercarboncapture.com
Drax	United Kingdom	www.drax.com
Fluor	United States	www.fluor.com
Blue Planet	United States	www.blueplanetsystems.com/
Carbon Clean	United Kingdom	www.carbonclean.com
Bright Renewables	Netherlands	https://www.bright-renewables.com/

3.2.3 Existing Projects – Carbon Clean

(a) Carbon Clean, for example, has 44 operational plants worldwide, as seen below:



(b) CCUS projects in US, Norway, Spain, & UK include:

   (i) **University of Kentucky:** 14 tonne per day solvent testing in pilot plant for carbon capture from coal-fired flue gases.

   (ii) **US Department of Energy / GTI:** 1 tonne per day advanced thermal capture for coal-fired flue gases.

   (iii) **Acorn UK:** UK's largest industrial CO_2 capture project

   (iv) **Technology Centre Mongstad:** Research and Testing facility in Norway

   (v) **Holcim, Spain:** 200 tonne per day carbon capture plant

3.3 Physical Separation

3.3.1 Process Description

(a) Based on either absorption, adsorption, cryogenic separation, or dehydration and compression.

(b) Physical adsorption makes use of solid surfaces (e.g., made of activated carbon, alumina, metallic oxides, zeolites). After capture, CO_2 can be released by increasing temperature (via temperature swing adsorption) or pressure (via pressure/vacuum swing adsorption).

(c) In actual commercial processes temperature swing adsorption is not as simple as increasing the temperature to decrease the quantity of CO_2 adsorbed. In reality, a hot gas or steam has to be passed through the adsorption unit to remove all the desorbed particles once the increase in temperature has been applied.

(d) Pressure swing adsorption can be accomplished through one of two (2) ways:

   (i) Reduction in the total system pressure

   (ii) Adding an inert gas to the mixture while maintaining the total system pressure

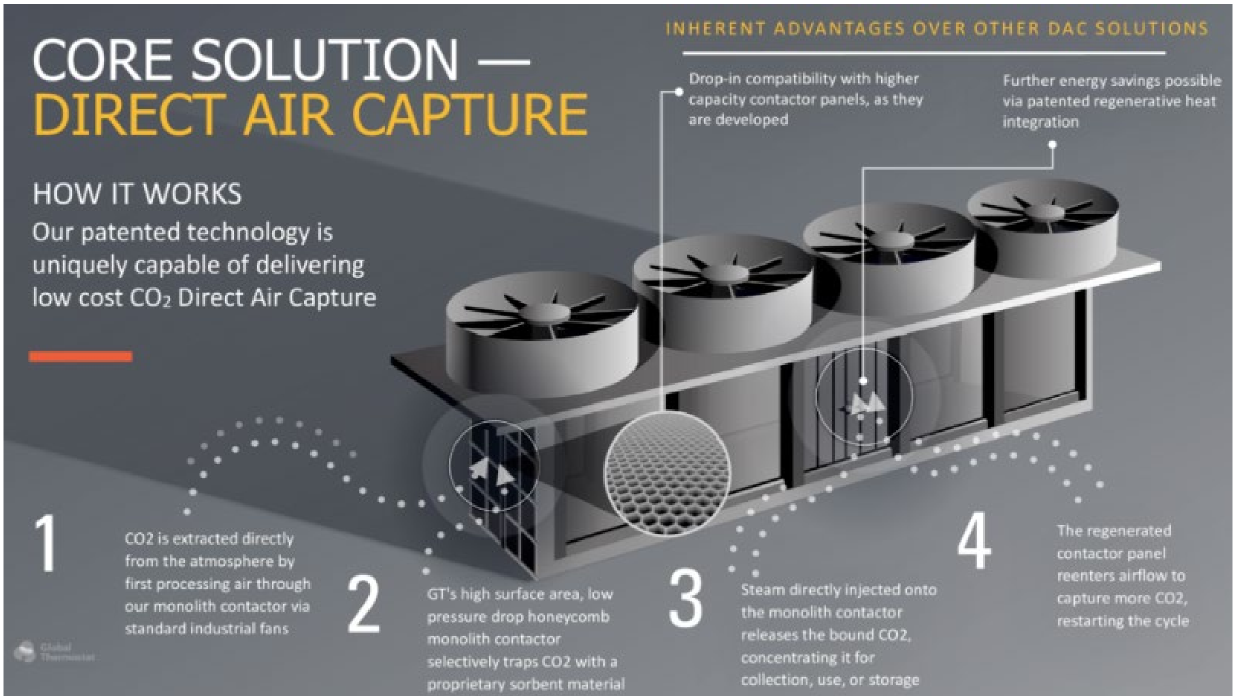
(e) Often a combination of both methods is used in practice. It should also be noted that changes of quantity adsorbed are usually observed much faster when carrying out pressure swing adsorption when compared to temperature swing adsorption.

(f) Physical absorption makes use of a liquid solvent (e.g., Selexol or Rectisol).

(g) Used in natural gas processing, ethanol, methanol, and hydrogen production.

(h) TRL: 7-9

(i) PFD:



3.3.2 OEMs

OEM	LOCATION	WEBSITE
Fresme	Belgium	www.fresme.eu
Svante	Canada	Svante | Carbon Capture & Removal Solutions (svanteinc.com)
Global Thermostat	United States	Global Thermostat

3.3.3 Existing Project (Svante) – LafargeHolcim

(a) One (1) tonne per day CO_2 captured from a cement plant.

(i) Located in Richmond, British Columbia, Canada.

(ii) Three (3) phase program focused on:

(b) Contaminant reduction

(i) CO_2 capture

(ii) CO_2 reuse

- Phase 1 began operation in 2019.
- Phases 2 and 3 began operation in 2020.

3.4 Oxy-fuel Combustion

3.4.1 Process Description

(a) Involves combustion of a fuel using nearly pure oxygen and the capture of CO_2 emitted. The use of pure oxygen ensures almost stoichiometric combustion.

(b) As a result, flue gas is mainly composed of CO_2 and water vapour. Water vapour is removed through dehydration to obtain a high purity CO_2 stream.

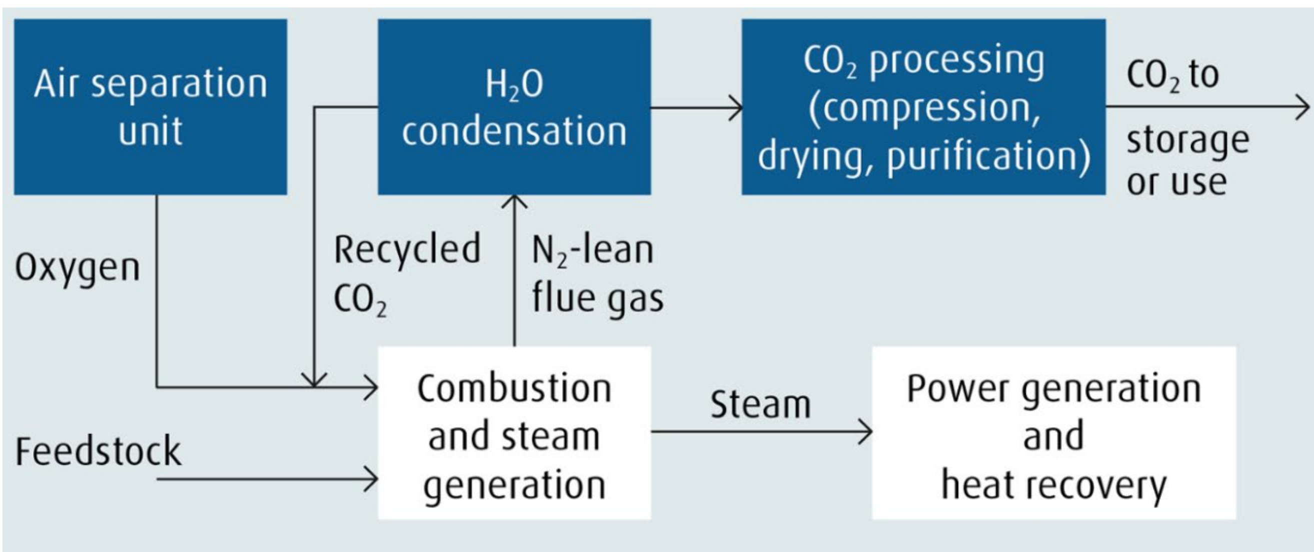
(c) Currently in large prototype/ pre-demonstration stage.

(d) Several projects have been completed in coal-based power generation and cement production.

(e) TRL: 6-8

(f) PFD:

Example (from Linde Engineering):



3.4.2 OEMs

OEM	LOCATION	WEBSITE
Linde Engineering	United Kingdom	Think Hydrogen. Think Linde. | Linde Engineering (linde-engineering.com)
Carbon Point	United States	Carbon Capture | CarbonPoint | United States
Babcock and Wilcox	United States	Clean Power Production Technologies » Babcock & Wilcox

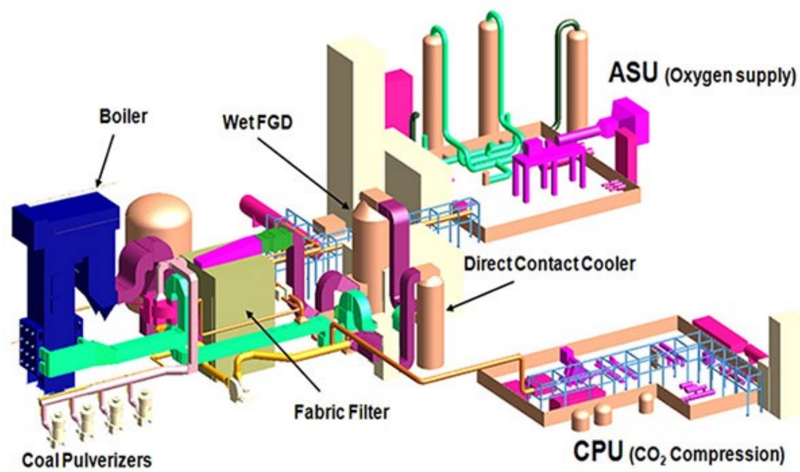
3.4.3 Existing Project – OxyBright (Babcock & Wilcox)

(a) In this process, typical boiler combustion air is replaced with pure oxygen from an ASU. Additionally, nitrogen, that is usually passed through the air-fuel mixture is left out from this process.

(b) A portion of flue gas with a high concentration of CO_2 is recirculated to a burner, acting as a substitute for nitrogen in the furnace.

(c) The flue gas that is not recirculated through the system, leaves the boiler, and is passed through particulate and sulfur removal systems. It then proceeds to a CPU where high purity CO_2 is produced.

(d) In 2014, Babcock & Wilcox began work on a project to provide this technology on the DOE Future Gen 2.0 demonstration project in Meredosia, Illinois. Due to a redirection of funding, the project was shut down in 2016. Despite this, Babcock & Wilcox still has the capabilities to commercialize and deploy this technology.



3.5 Membrane Separation

3.5.1 Process Description

(a) Based on polymeric or inorganics membranes with high CO_2 selectivity, i.e., they let CO_2 pass but act as barriers to other gasses in the stream.

(b) Technology readiness varies with fuel and application:

(i) For natural gas processing: Demonstration stage.

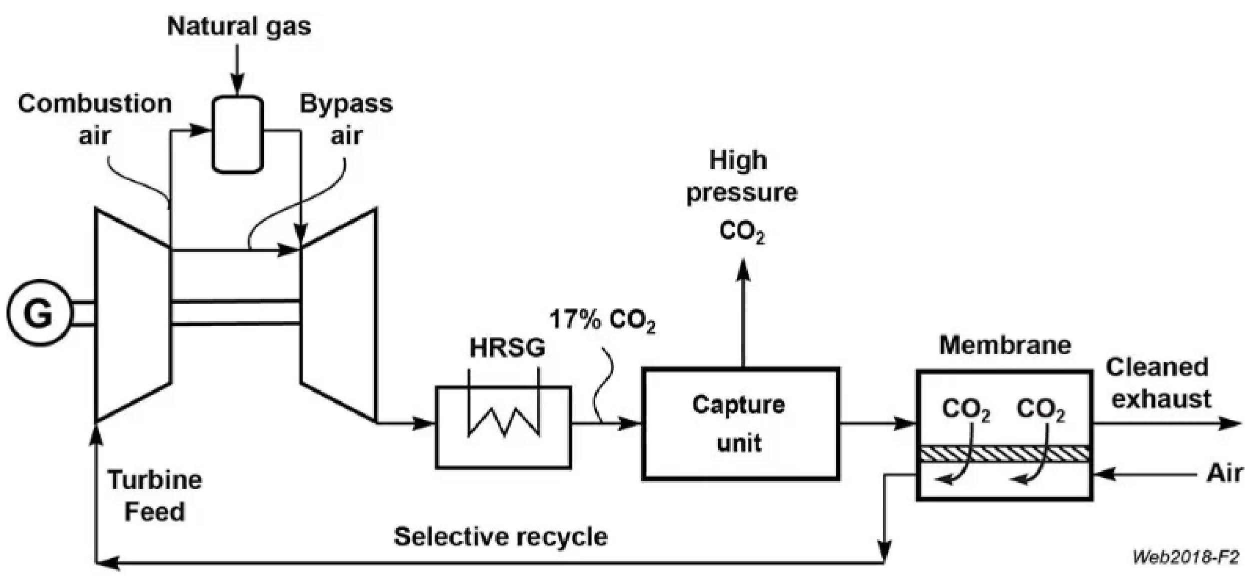
(ii) Membranes for CO_2 removal from syngas and biogas are commercially available.

(iii) Membranes for CO_2 removal for flue gas treatment are still in development.

(c) The only large-scale operational membrane separation capture plan is operated by Petrobras in Brazil.

(d) TRL: 6-8

(e) PFD (shows a membrane technology, from MTR, operating in tandem with flue gas recirculation and a secondary CO_2 capture unit):



3.5.2 OEMs

OEM	LOCATION	WEBSITE
Generon	United States	Nitrogen Systems and Gas Solutions | GENERON
MTR – Membrane Technology Research	United States	Home - Membrane Technology and Research (mtrinc.com)

3.6 Calcium Looping

3.6.1 Process Description

(a) Calcium Looping is a specific sub-technology of chemical looping.

(b) Calcium Looping is regarded as a front-runner chemical looping technique for certain industries such as cement production.

(c) CO_2 is captured at high temperatures using two (2) main reactors.

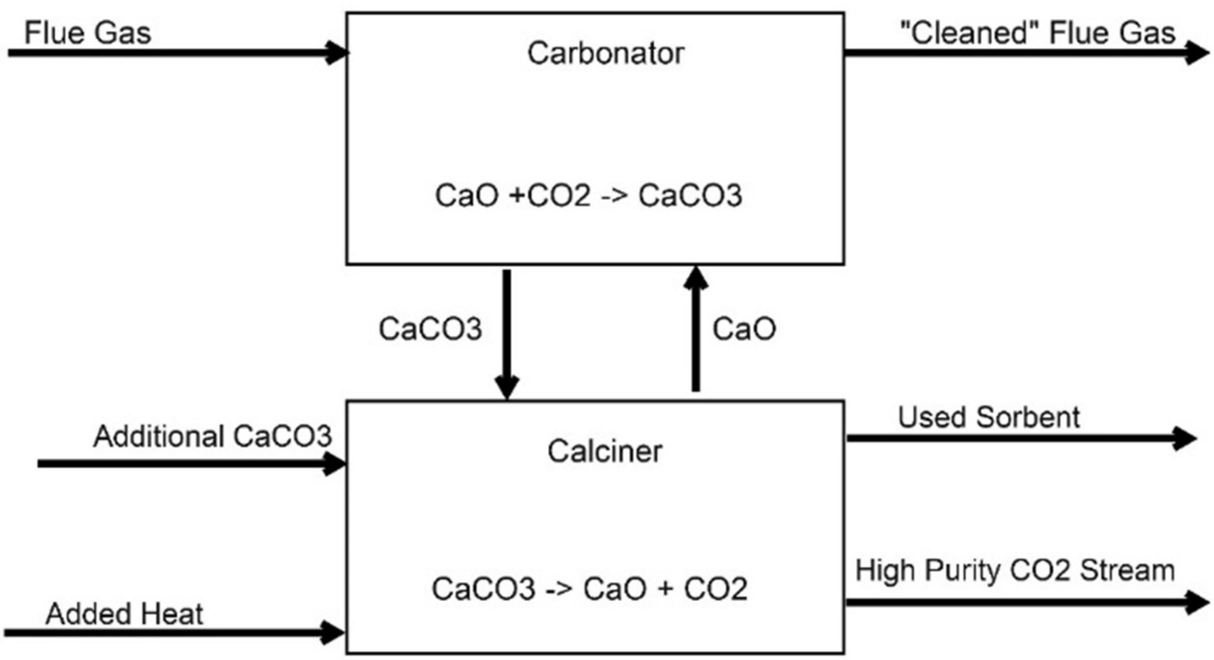
(d) In the first reactor, lime (CaO/calcium oxide), is used as a sorbent to capture CO_2 from a gas stream and forms calcium carbonate ($CaCO_3$)

(e) The $CaCO_3$ is transported to the second reactor where it is regenerated, the result is lime and a pure stream of CO_2. The lime is looped back to the first reactor.

(f) A pilot/pre-commercial stage has been tested in coal-fired fluidized combustors and a cement manufacturer.

(g) TRL: 5-7

(h) PFD:



3.6.2 OEMs

OEM	LOCATION	WEBSITE
CLEANKER	Italy	CLEANKER is a project addressing CO2 capture from cement production
ITRI (Industrial Technology Research Institute)	Taiwan	Industrial Technology Research Institute (itri.org.tw)

3.6.3 Existing Project (CLEANKER) – Buzzi Unicem

(a) The target for this pilot project is to demonstrate at TRL = 7, the calcium looping process. A process which is believed to be the most promising for being able to reduce the CO_2 emissions produced by the global cement/concrete industry.

(b) Pilot project is taking place at a cement plant in Vernasca, Italy which is operated by Buzzi Unicem.

(c) The biggest difference between the CLEANKER project and past attempts to capture CO_2 at cement plants is that with the CLEANKER project the CO_2 capture takes place during combustion, not after.

(d) Tests at the Buzzi Unicem plant currently involve processing 1% of kiln flue gases.

(e) The current layout at the cement plant can be compared to the new calcium looping layout in the figures below:

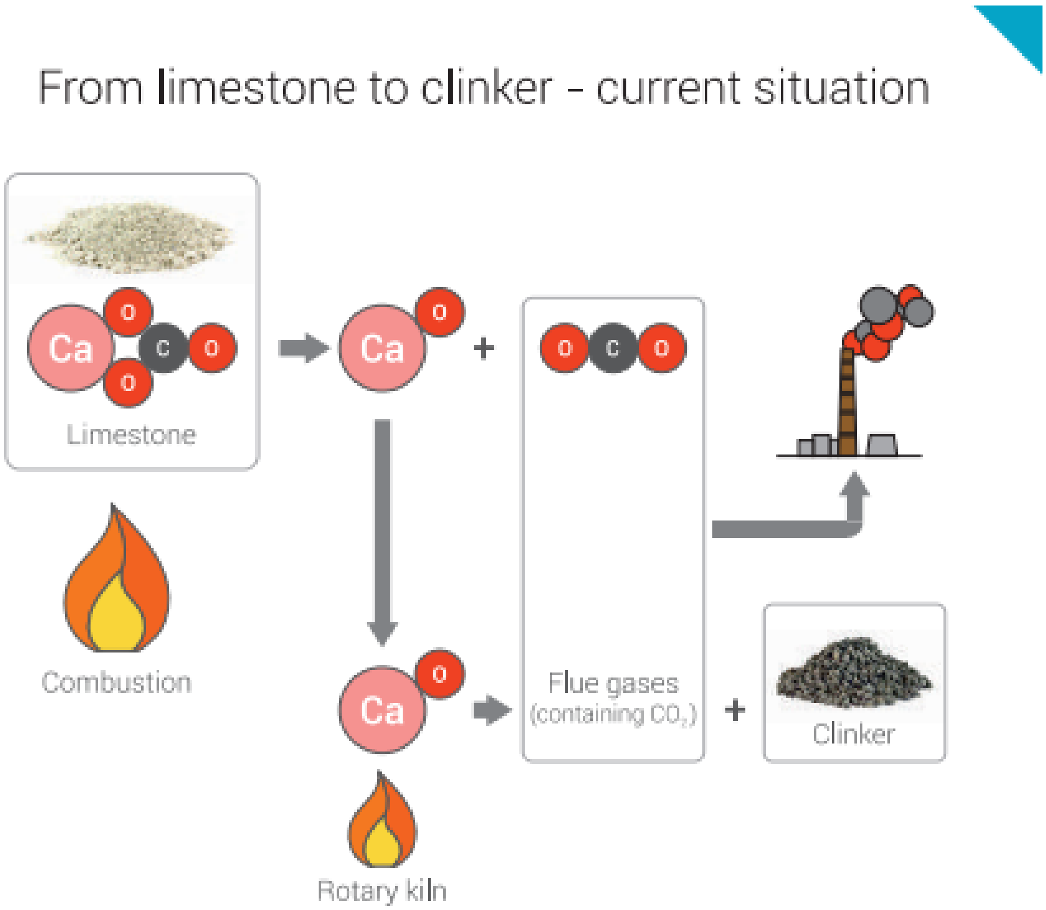
(f) A few of the main objectives/targets for this project:

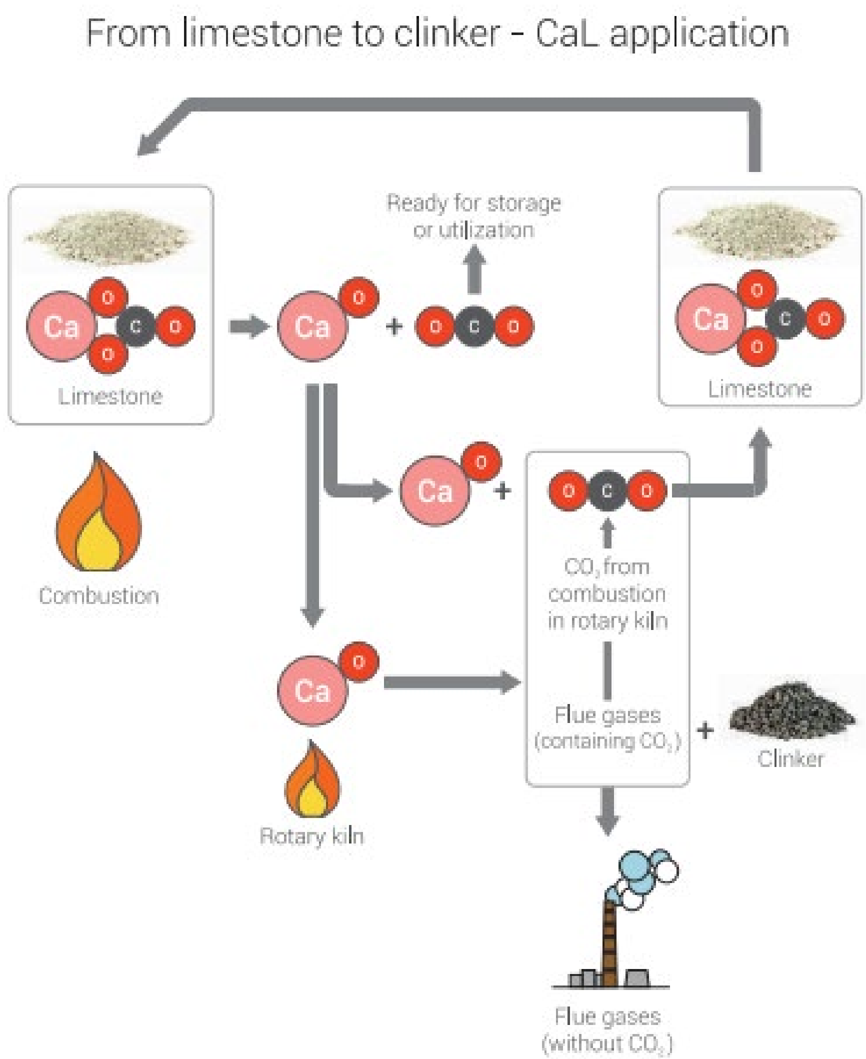
(g) Carbon Capture Efficiency > 90%

(h) Negative direct CO_2 emissions by biomass co-firing

(i) Keep the inevitable increase in cost of cement to less than 25 € / tonne

(j) Rough Process Description (CLEANKER Flyer):


From limestone to clinker - current situation
Ca
O
C
O
O
Limestone
Combustion
Ca
O
+
O
C
O
Ca
O
Rotary kiln
Flue gases
(containing CO2)
+
Clinker


From limestone to clinker - CaL application
Ready for storage or utilization
Ca
O
C
Limestone
Combustion
+
CO_2 from combustion in rotary kiln
Flue gases (containing CO_2)
Clinker
Rotary kiln
Flue gases (without CO_2)

3.7 Chemical Looping

3.7.1 Process Description

(a) In general, Chemical Looping technologies include two reactors.

(b) In the first reactor, small metal particles (e.g., iron, manganese, etc.) are used to bind oxygen from the air and form metal oxides.

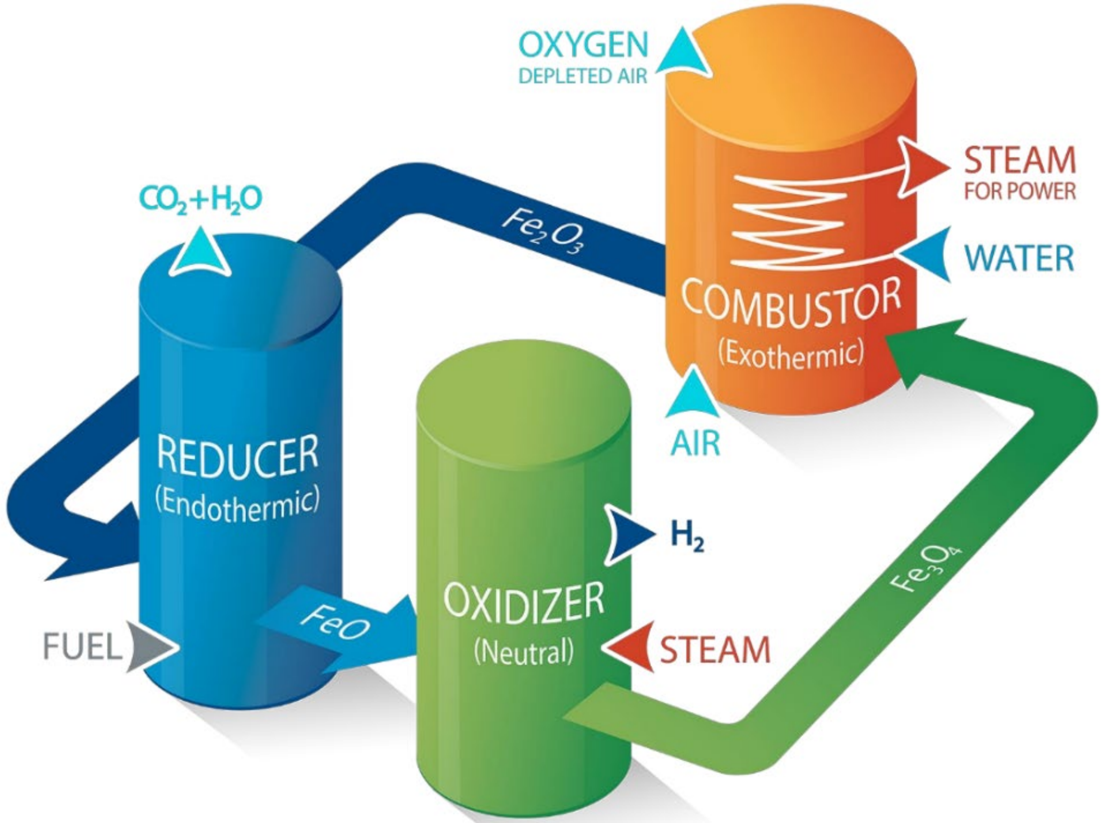
(c) These metal oxides are transported to a second reactor where they are reacted with fuel (i.e., oxides provide oxygen for the combustion reaction). Energy and a concentrated stream of CO_2 are produced. This process regenerates the metal in its reduced form (i.e., without oxygen) and is looped back to the first reactor.

(d) Chemical looping has been tested through the operation of 35 pilot projects with coal, gas, oil, and biomass combustion.

(e) TRL: 5-7

(f) PFD:

Example (from Babcock & Wilcox):



3.7.2 OEMs

OEM	LOCATION	WEBSITE
Babcock and Wilcox	United States	Clean Power Production Technologies » Babcock & Wilcox
DemoCLOCK	Europe	DemoCLOCK (sintef.no)
CHEERS	China	CHEERS | Innovation and Networks Executive Agency (europa.eu)

3.7.3 Existing Project – DemoCLOCK

(a) Intended to demonstrate the technical, economic, and environmental feasibility of implementing PRB-CLC in large-scale power plants.

(b) Project Objectives:

(i) Design, build, integrate, and operate a medium sized (500 kW) fixed bed reactor into the existing IGCC power plant at Elcogas, Spain.

(ii) Select suitable, inexpensive, and available mineral for CLC operations as an oxygen carrier.

(iii) Assessment of the economic advantages of using packed bed CLC for power production in a CO_2 emissions free plant.

(iv) Assess the potential of integrating a PBR-CLC system in a large-scale coal fired power plant and to tentatively exceed the performance of the current commercial technologies in terms of efficiency and CO_2 capture.

(c) Technology Utilized

(i) Chemical looping CO_2 capture

(ii) PBR-CLC uses a fixed bed unlike regular chemical looping plants

(iii) A fixed bed reactor is a cylindrical tube filled with catalyst pellets with reactants flowing through the bed while being converted into products.

(iv) PBR-CLC system will run on five (5) subsequent cycles: Oxidation phase (to generate heat by oxidating the reactor bed), purge, reduction phase (to reduce the bed at elevated temperature, i.e., restore the pure metal from the metal oxide), purge and heat removal phase using Nitrogen to push the heat out of the reactor.

(v) Purging, the purging process refers to the introduction of an inert gas (mostly non-combustible) in a closed system to prevent the formation of an ignitable atmosphere.

(vi) Potential materials to act as the oxygen carriers for fixed bed CLC operations have been selected. The phase (WP1) of developing new oxygen carrier materials for fixed bed CLC operations is nearing its completion.

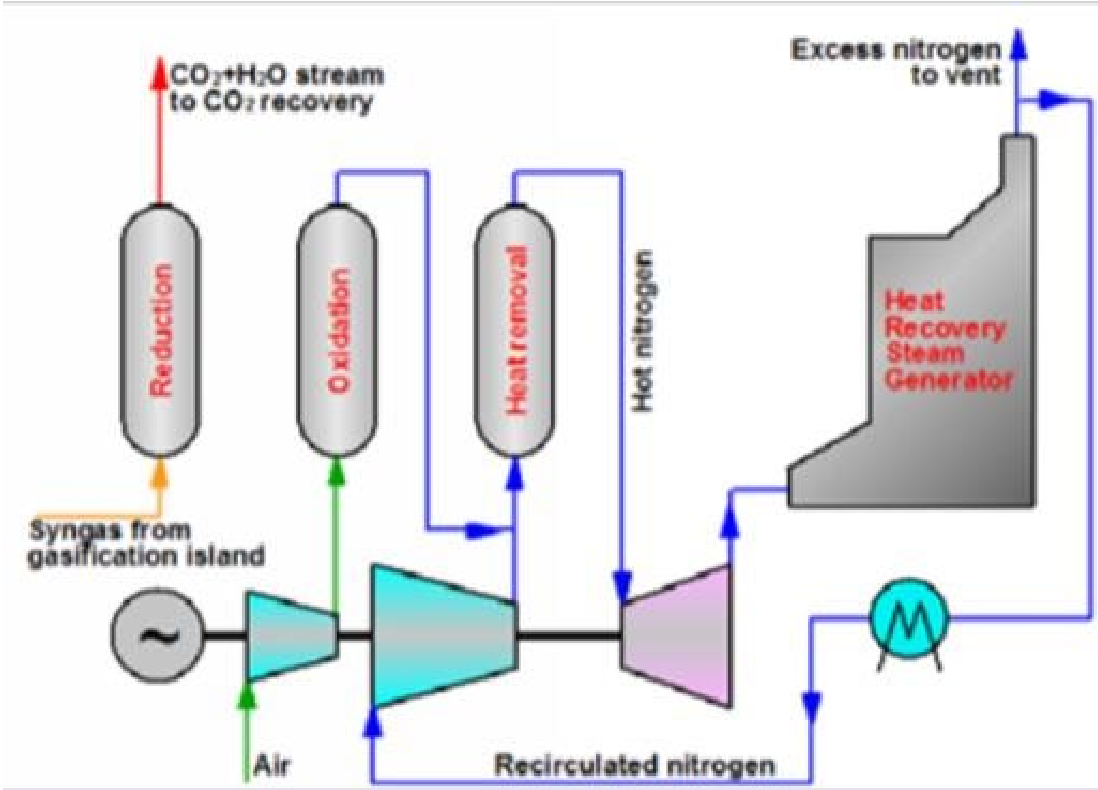
(d) PFD (Brochure):

(i) Implementation plan for a large-scale CLC-based power plant

(ii) Modified gas turbine combined cycle configuration using gasified coal (syngas production process pictured off diagram).

(iii) Heated nitrogen gas is the working fluid for the gas turbine (which also drives an air and nitrogen compressor) before heat recovery in an HRSG.

(iv) The modified gas turbine combined cycles below is the most feasible configuration for use of a PBR-CLC system in a coal fired power plant.



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3.8 Direct Separation

3.8.1 Process Description

(a) Used to capture CO_2 from cement production.

(b) Limestone is indirectly heated using a special calciner (steel cylinder that rotates inside a heated furnace and performs indirect high-temperature processing within a controlled atmosphere).

(c) This application is a process change for the cement industry, and as such, utilizes thermal energy already used by the cement process.

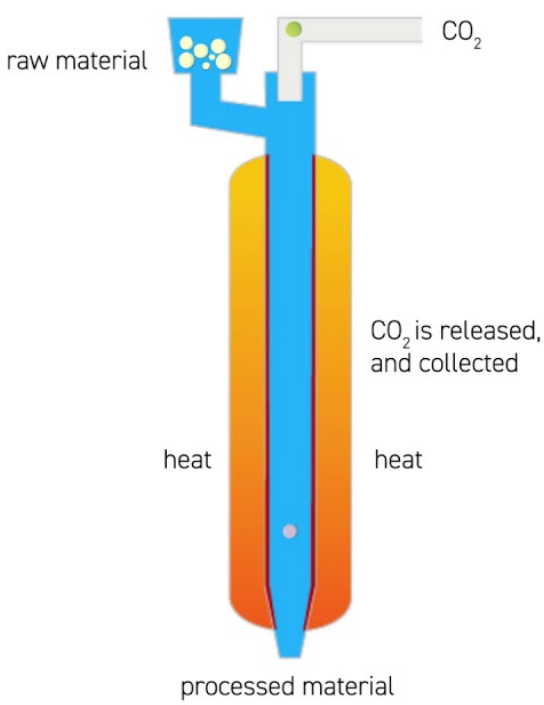
(d) This process does not require the use of any chemical solvents and does not seek to decarbonize the production of thermal energy.

(e) CO_2 is directly stripped from the limestone without mixing it with other combustion gases, thus considerably reducing the costs related to gas separation.

(f) Currently being tested in pilot projects, e.g. The Low Emissions Intensity Lime and Cement (LEILAC) plant developed by Calix at Heidelberg Cement plant in Lixhe, Belgium.

(g) TRL: 5-6

(h) PFD:



Using Calix's LEILAC technology, the released CO_2 is not contaminated. This carbon capture process does not require additional energy or chemicals.

Leilac
www.project-leilac.eu

3.8.2 OEMs

OEM	LOCATION	WEBSITE
Calix	Australia	Calix | Agriculture, Wastewater, Infrastructure Solutions & More

3.8.3 Existing Project – LEILAC (Calax)

(a) Location: Lixhe, Belgium

(b) LEILAC, or Low Emissions Intensity Lime and Cement is a pilot project that aims to “future-proof” the cement and lime industries for more stringent CO_2 emissions standards to come.

(c) This is being accomplished using the breakthrough, direct separation, technology developed by Calax. This method was developed with the aim to capture the CO_2 emissions emitted from raw limestone.

(d) The process involves heating the limestone using a particular steel reactor. This allows pure CO_2 to be captured as it is released from the limestone and the rest of the furnace exhaust gases are held separate.

(e) To account for the emissions associated with the heating of the limestone, the aim is to be able to use any type of fuel for these furnaces (i.e., biomass, hydrogen, or even electricity).

(f) With this pilot project, LEILAC-1, up and running successfully, the plant can separate CO_2 at a rate of around 18,000 tonnes/ yr.

(g) The success of LEILAC-1 has no doubt influenced the decision to undertake a follow-on project, LEILAC-2. LEILAC-2, which started in 2020, received €16m of funding and aims to be operational by 2023. LEILAC-2 will be a Demonstration Plant that will separate 20% of the regular plants process emissions (equivalent to about 100 ktpa).

3.9 Bioenergy Carbon Capture, Utilization, and Storage (BECCUS)

3.9.1 Process Description

(a) BECCUS are a group of technologies that produce Energy from Biomass and Utilize or Store the CO_2.

(b) This post combustion carbon capture process involves burning biomass, then using solvents to separate the CO_2 from the flue gases. The CO_2 is then pressurised and condensed into a liquid so it can be transported, utilized, or stored.

(c) Most of the “true” BECCUS technologies are algae and microbial-based bioreactors which sequester CO_2 in a biomass material (such as PondTech), however several other technologies are “cross-compatible”, such as Biomass Combustion and Chemical Absorption, and can be defined as BECCUS when combined in operation.

(d) Some forms of Biomass Thermochemical Conversion technologies, such as gasification or pyrolysis (such as CHAR Technologies), also produce a biochar, which is considered a “sequestered carbon” product (equivalent to sequestering CO_2 geologically or mineralizing CO_2). This qualifies these technologies as net-negative and a form of BECCUS.

(e) TRL: 5-9

(f) PFD:

Flow Chart of the BECCUS Concept:

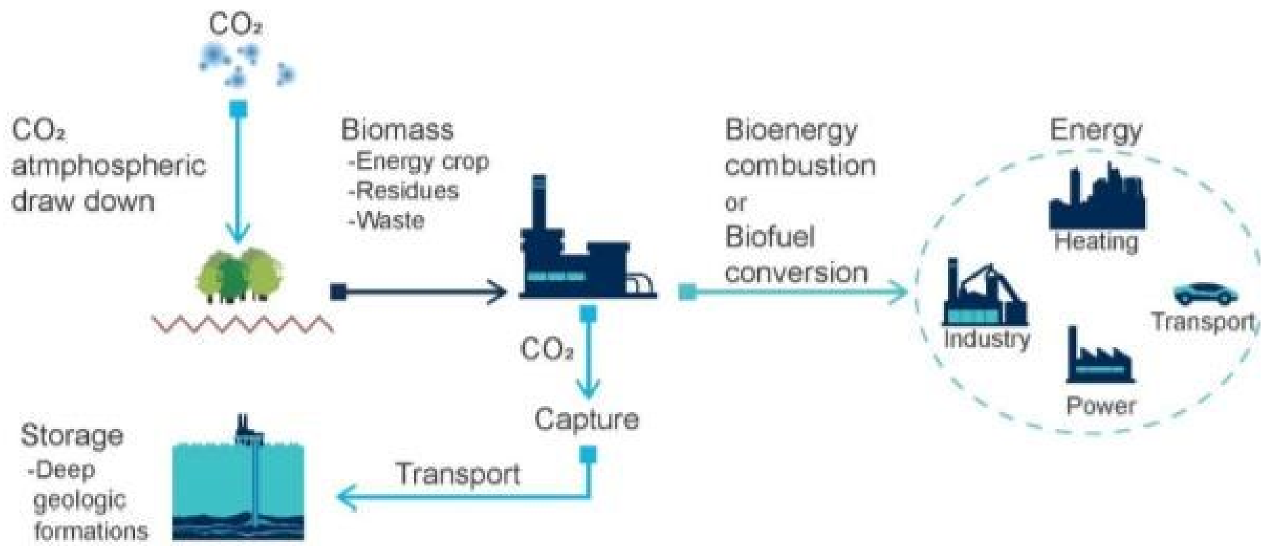


Figure 1: Bioenergy and carbon capture and storage (BECCS) schematic

3.9.2 OEMs

OEM	LOCATION	WEBSITE
LanzaTech (Microbial)	United States, China, and India	LanzaTech
Hy-Tek Bio (Algae)	United States	HY-TEK Bio, LLC. | Reduces Power-Generating Facility's Carbon Footprint (hytekbio.com)
PondTech	Canada	Home – Pond Tech
Drax	United Kingdom and North America	Home – Drax Global
Syncraft	Austria	SYNCRAFT® - Das Holzkraftwerk
CHAR Technologies	Canada	Home – CHAR Technologies

3.9.3 Existing Project (PondTech) – Markham District Energy

(a) Location: Markham, Ontario, Canada

(b) Industry: Power generation.

(c) Partner: Marham District Energy

(d) Algae Bioreactors: 200,000 L capacity.

(e) CO_2 captured and utilized at 21 kg/hr (183 tonnes/yr)

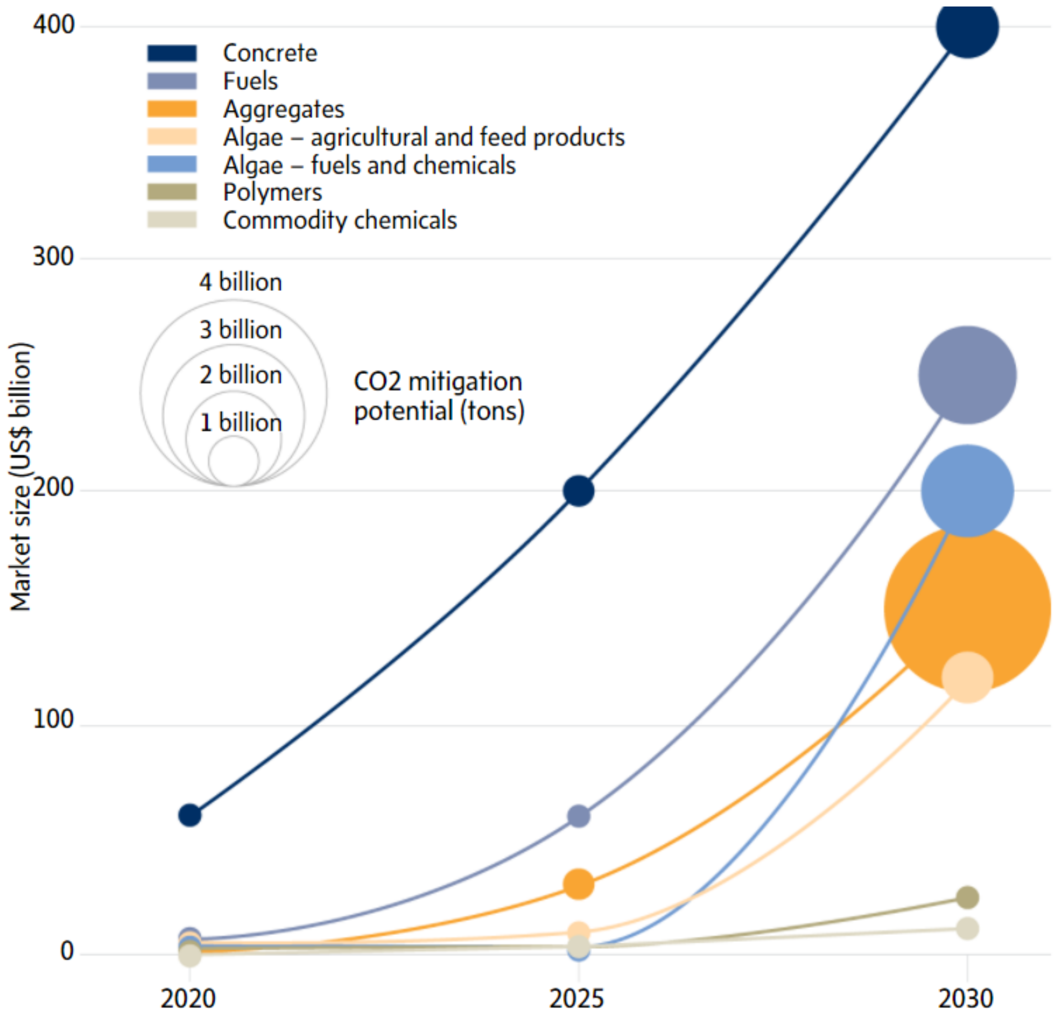
(f) Markham District Energy and Pond Tech has partnered to develop a nutraceutical algae facility to produce food/medical supplements such as astaxanthin, chlorella, and spirulina.

Please refer to Appendix B for the list of references used in this section of the report.

4/ METHODS TO UTILIZE CAPTURED CO_2

4.1 CO_2 Use Overview

(a) For jurisdictions without adequate geology for CO_2 sequestration, CO_2 utilization is essential to decarbonizing existing infrastructure without ceasing to combust fossil fuels.



THE GLOBE AND MAIL, SOURCE: CARBON UTILIZATION – A VITAL AND EFFECTIVE PATHWAY FOR DECARBONIZATION, SUMMARY REPORT, CENTER FOR CLIMATE AND ENERGY SOLUTIONS (C2ES)

(b) CO_2 is already utilized in large quantities globally (130 million tonnes per year) for urea production (IEA).

(c) Emerging markets for CO_2 utilization falls into three (3) main categories

(i) Production of Materials/Chemicals (e.g., mineralization)

(ii) Production of Food & Beverages (e.g., greenhouse gassing)

(iii) Production of Fuels

4.2 Mineralization

(a) Mineralization is the only accepted utilization of CO_2 that also constitutes complete "destruction" of CO_2.

(b) That is, mineralization is equivalent to CO_2 storage, in that the mineral compounds produced are chemically stable for 100+ years, if properly handled.

(c) These same minerals can also be used in various industrial processes; this means mineralization can be both a utilization and storage activity.

(d) For example, these minerals can be used as an additive for aggregate in concrete production

(e) Another use for these minerals are as low-value crop enhancements, which result in greater crop yields.

(f) The economic value of mineralization is heavily tied to the carbon credits it can produce.

(g) For some "Big Tech" companies, which focus on using carbon credits to reduce their Scope emissions, the value of mineralization can be ~450 USD/tonne.

(h) Companies like Blue Planet, Carbon Free, and Carbon8 are leading commercial development for this industry.

(i) For example, Carbon Free's SkyCycle and SkyMine technology are able to produce Sodium Biocarbonate (baking soda), PCC, and hydrochloric acid. All of these being products that are heavily used in everyday life.

(j) In addition, Blue Planet's technology enables them to produce aggregate for which every tonne contains about 970 lb of CO_2, concrete, and limestone with which the reflectance is high enough that it has become an ideal material for roof shingles or high albedo surfaces.

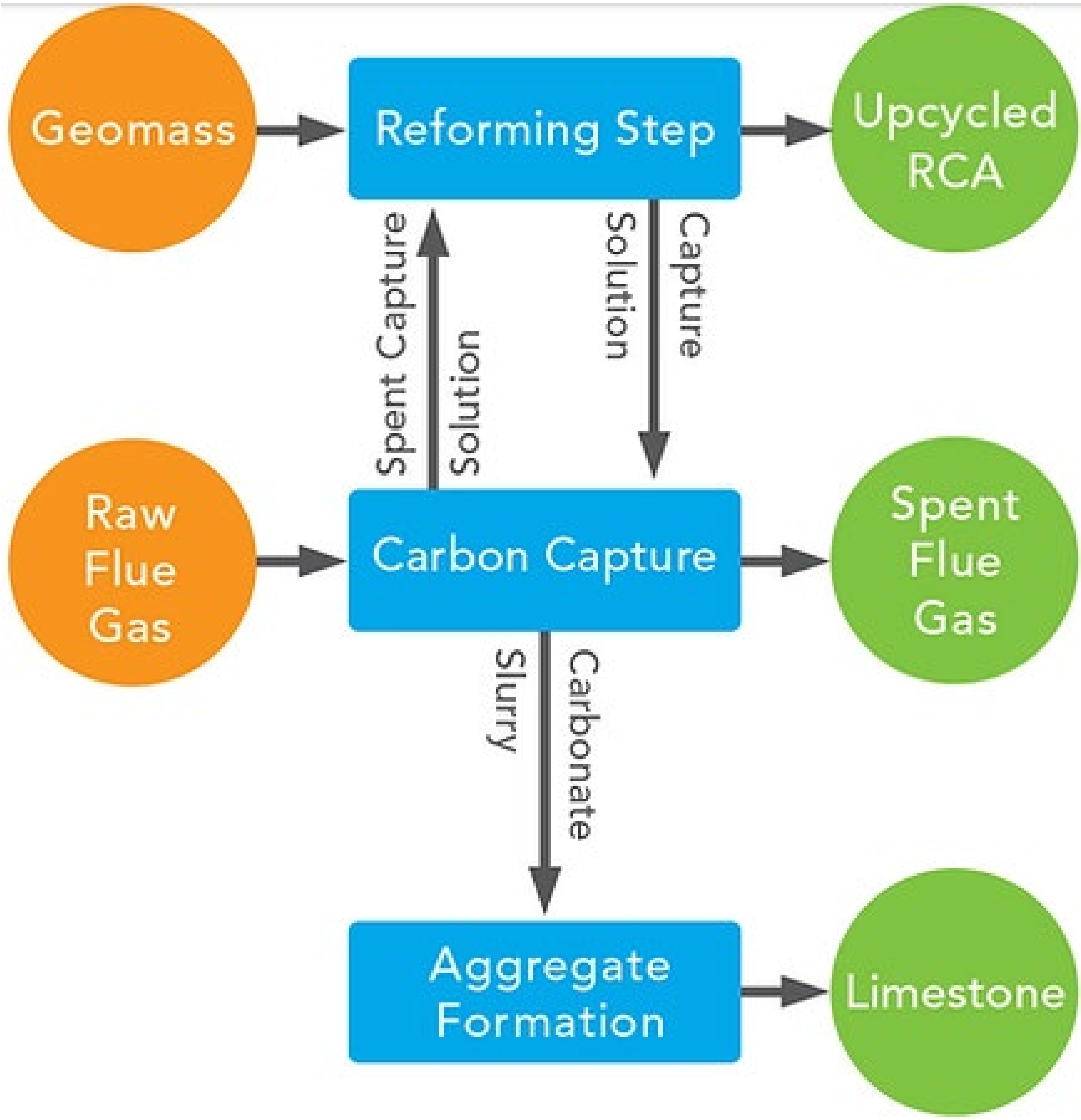
(k) The company provides a circular solution in which the only required inputs are waste, waste concrete, and CO_2.

(l) TRL for mineralization depends on the mineral being produced. For example:

(i) Concrete Additives – TRL: 4-8

(ii) Concrete Curing – TRL: 7-8

(m) PFD (Geomass, a source of calcium for the mineralization process, is used to regenerate the carbon capture solution while producing a valorized/upcycled calcium product - TECHNOLOGY | Blue Planet Systems):



4.2.1 OEMs

OEM	LOCATION	WEBSITE
Clean O2	Canada	CleanO2
Carbon Upcycling	Canada	Technology - Carbon Upcycling
Skyonic	United States	Skyonic (osti.gov)
Carbon Free	United States	CarbonFree - Our mission is to capture 10% of the world's industrial CO2
Blue Planet	United States	Permanent Carbon Capture | Blue Planet Systems | Los Gatos
Neustark	Switzerland	HOME | neustark
Carbon8	United Kingdom	Carbon8
Hyperion Global Energy	Canada	Hyperion Global Energy (hyperionenergy.ca)
Solidia	United States	Solidia® – Making Sustainability Business As Usual℠ (solidiatech.com)
Carbicrete	Canada	Carbon-Negative Concrete | Carbicrete

4.3 Greenhouse Gassing

(a) Process involves adding captured CO_2 to a greenhouse to enhance growth rates.

(b) Although it is not the only factor when it comes to growth of plants indoors, CO_2 is often looked at as the limiting factor for the maximum growth of plants.

(c) For that reason, this process of greenhouse gassing is often referred to as "CO_2 enrichment" or "CO_2 fertilization".

(d) There are several ways to attain this excess CO2 that is required, each with their own benefits and drawbacks:

(i) Pulling excess ambient air into the greenhouse via a fan to bring in more CO_2.

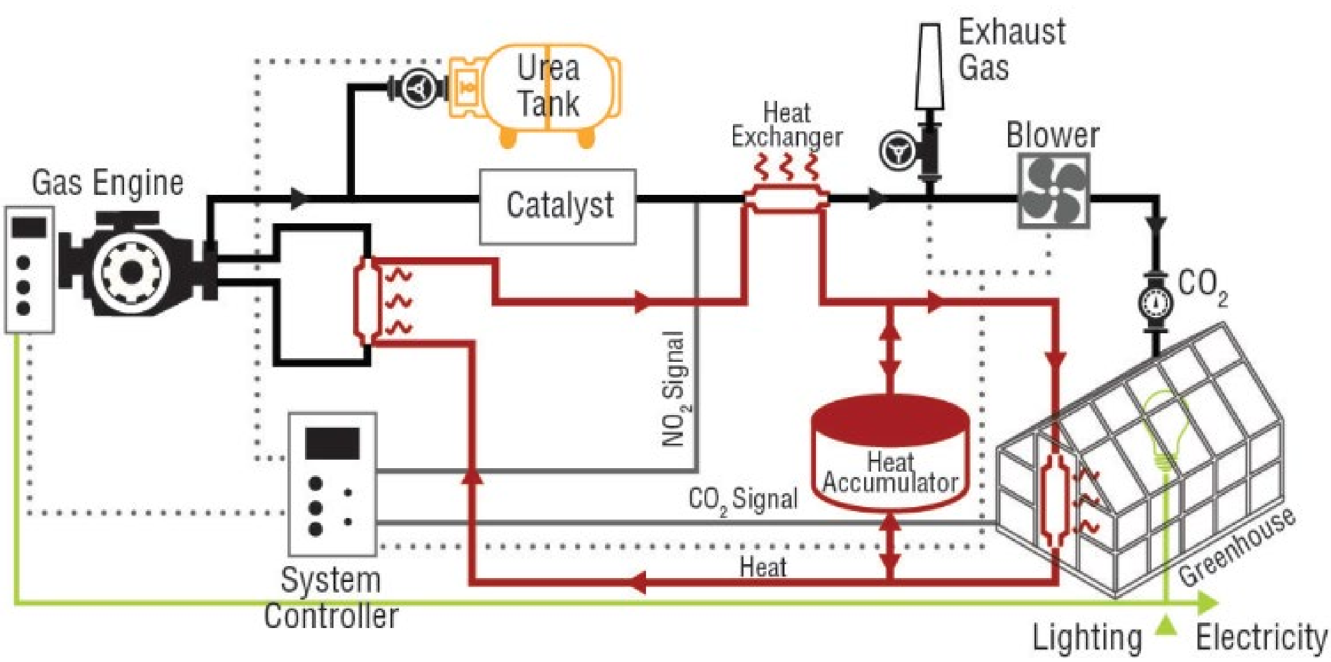
(ii) Compressed CO_2 is stored in tanks and spread throughout the greenhouse via PVC piping when necessary.

(iii) CO_2 Generators – Combustion of hydrocarbons produces CO_2. Care must be taken to ensure that the plants do not get exposed to any of the other byproduct gases such as carbon monoxide and nitrogen oxides.

(e) ~ 100 USD/tonne

(f) TRL: 8-9

(g) PFD (showing CO_2 generation for a greenhouse – CO_2 tanks can be used in place of the CHP pictured below to increase CO_2 concentration):



4.3.1 OEMs

OEM	LOCATION	WEBSITE
Greencap Solutions	Norway	Greencap Solutions (greencap-solutions.com)
BioTherm	United States	BioTherm Solutions for Greenhouse Growing Technologies
Infinitree	United States	Technology — Infinitree LLC
Bright Renewables	Netherlands	Bright Renewables | Biogas Upgrading, CO2 Capture & Liquefaction (bright-renewables.com)

(a) Infinitree offers a unique solution to the greenhouse CO_2 enrichment problem, with several benefits:

(i) Few moving parts and requires minimal energy input

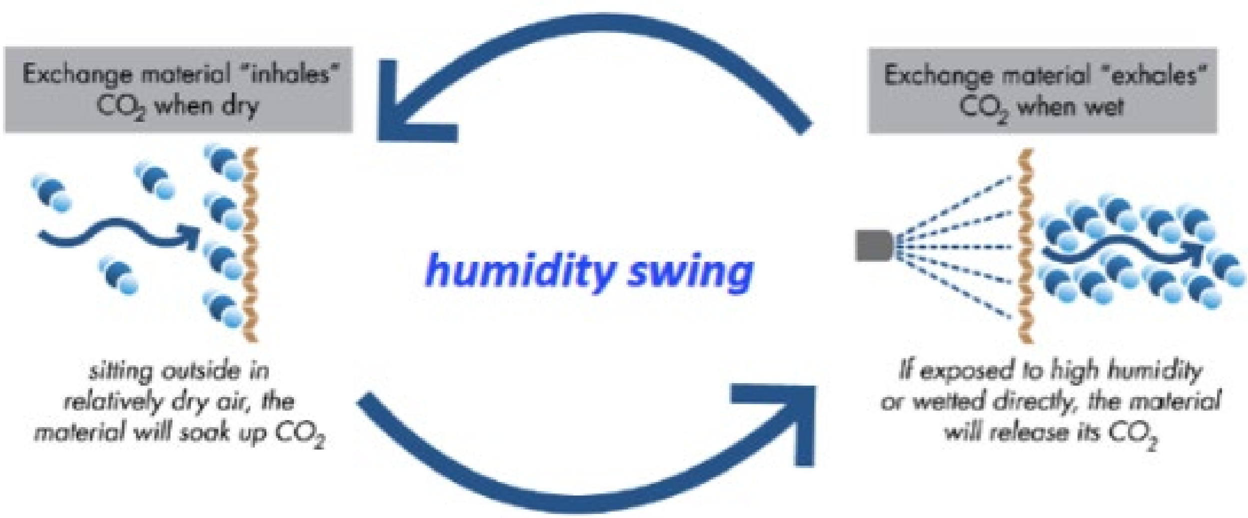
(ii) No combustibles required

(iii) Scalable technology

(b) The technology works such that CO_2 is extracted from dry ambient air and releases the captured CO_2 into the greenhouse.

(c) The key is an ion exchange sorbent material that concentrates that atmospheric CO_2 and discharges when required.

(d) The sorbent works such that is takes in CO_2 when dry and exhales it when it is wet:



(e) As mentioned above Bright is another company involved in utilizing captured CO_2 for greenhouse enhancement.

(f) Bright's modular capture units can range in size from 800-8000 kg/hr (2-20 MWt boiler installations) and can deliver CO_2 in either the gaseous or liquid form, depending on whether clients choose to select the CO_2 liquefaction system.

(g) Bright's chemical absorption-based technology uses amine-based solvents to absorb and separate the CO_2 from the exhaust flue gases of a boiler.

(h) As far as the optional liquefaction system goes, the process can be broken down into several steps:

- (i) Filter – Gaseous CO_2 is passed through a filter to remove any impurities.
- (ii) Compressor – Filtered gas is then passed through a two-stage compressor to pressurize the gas.
- (iii) Dryer – Moisture is removed by passing the gas through an automatic sieve dryer.
- (iv) Condenser – CO_2 gas is condensed from gaseous form into a liquid form.
- (v) Stripping Tower – Any leftover non-condensable including oxygen, methane and nitrogen are removed from the mixture as it passes through the stripping tower.
- (vi) Storage Tank – The pure liquid CO_2 is allowed to flow into a insulated storage tank for later use.

(i) For greenhouse farmers that already have biomass-fired boiler plant, the addition of the Brights carbon capture technology gives them a fully circular cycle.

(j) The captured carbon can be used as additional income, particularly in months where heat demand is low. The local production of CO_2 helps to reduce transport distances and the overall cost of CO_2.

4.4 Production of Fuels

(a) Production of fuels using CO_2 is an essential activity of the circular economy (burning fuels produces CO_2 which is then used to make more fuels).

(b) These fuels produced using captured CO_2 be used as a drop-in fuel replacement for existing equipment.

(c) Commercially this process could produce fuels ranging from methane to kerosene to sustainable aviation fuel.

(d) Fuels produced from CO_2 are more expensive when compared to their fossil fuel counterparts.

(e) The difference is due in large part to the costs associated with the production of the hydrogen by electrolysis (a necessary step to producing most of the e-fuels). It is estimated that the hydrogen production step takes up about 60% of the total costs in the e-fuel production.

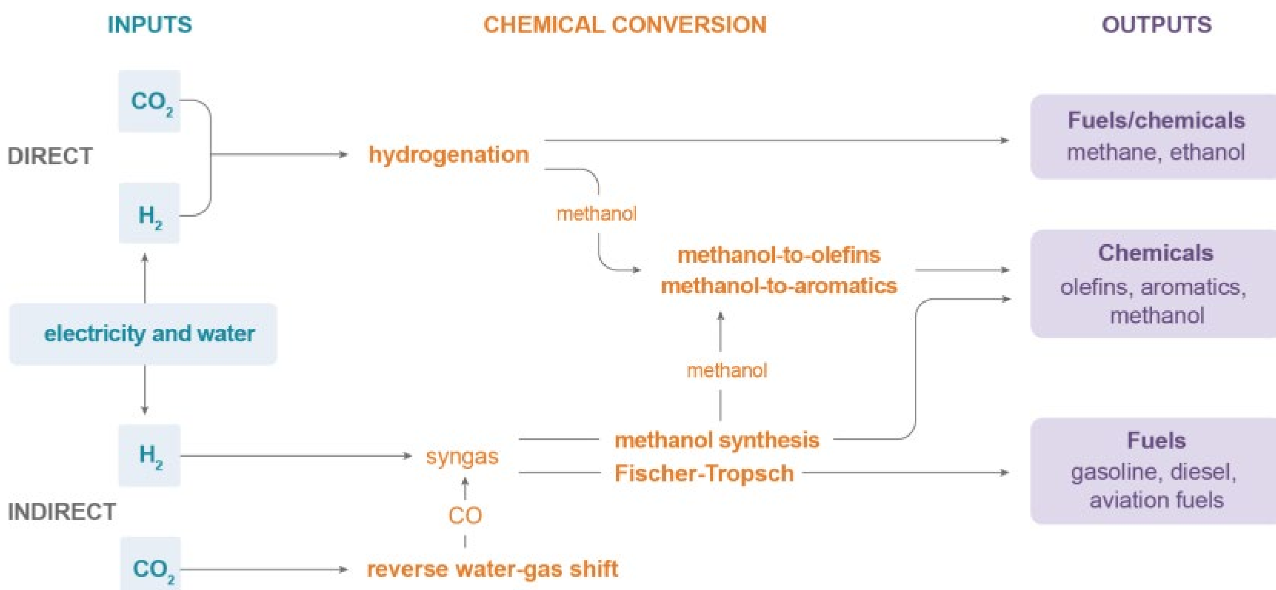
(f) It is believed that the cost to carry out electrolysis will drop in the near future, as a result of lower capital expenditures and lower renewable electricity costs.

(g) The TRL for this sector varies depending on the type of fuel being produced, for example:

(i) Methane Production – TRL: 8-9

(ii) E-Gasoline, E-Diesel and E-Kerosene Production– TRL: 5-9

(h) PFD (Fuel Production pathways using CO_2 per the IEA):



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4.4.1 OEMs

OEM	Location	Website
Dimensional Energy	United States	Home (dimensionalenergy.com)
Prometheus Fuels	United States	Home (prometheusfuels.com)
Ineratec	Germany	INERATEC – Innovative Chemical Reactor Technologies
Synhelion	Switzerland	Synhelion turns CO2 into fuel.
Topsoe	Denmark	Topsoe
Opus 12	United States	About Us | Twelve
Cemvita Factory	United States	Cemvita Factory Inc. | Economical carbon-negative solutions for a sustainable future

Please refer to Appendix B for the list of references used in this section of the report.

5/ OEMs Which Both Capture and Utilize CO_2

5.1 Standard Carbon

(a) Standard Carbon's technology is a modular, shipping container sized energy facility that can cut down carbon emissions from any combustion engine and convert them into usable natural gas.

(b) The process takes place in 5-minute spurts and is driven by electricity that is purchased on the spot market.

(c) Taking advantage in the difference in prices between spot electricity and day-ahead natural gas prices allows for the conversion of CO_2 into an asset, while maintaining zero emissions.

(d) Standard Carbon's technology varies in scale from 5 kW_e all the way up to 500 MW_e power plants. However, the fundamental elements of technology remain the same at all sizes:

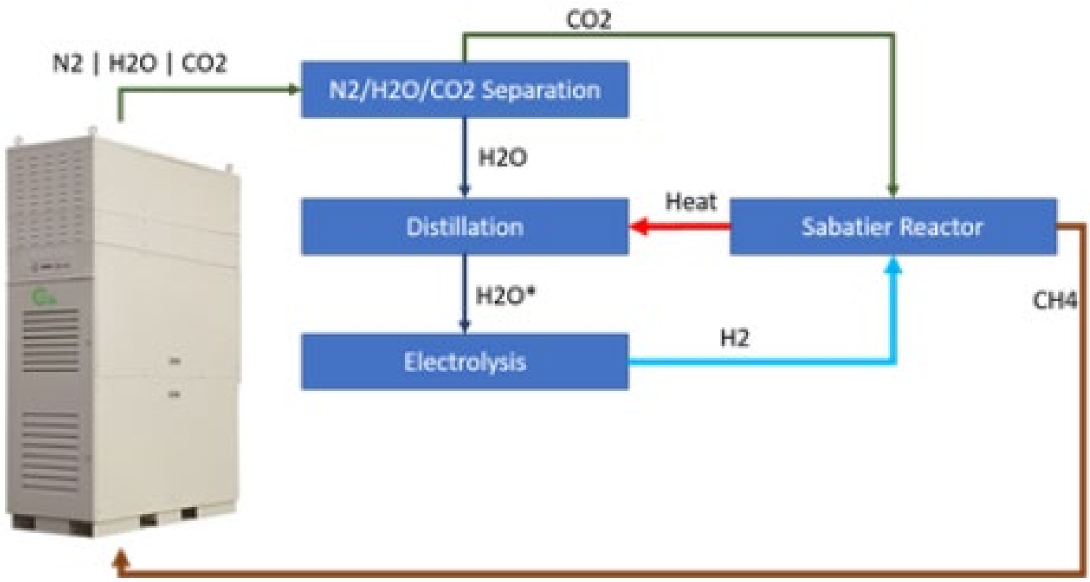
- (i) Capture exhaust gases from combustion engine.
- (ii) Separate the water vapor from the exhaust gases.
- (iii) Separate the nitrogen from the exhaust gases.
- (iv) Distill the water to produce pure water.
- (v) Electrolysis is applied to the water to produce hydrogen gas.
- (vi) Carbon dioxide is mixed with the hydrogen in a Sabatier reactor to produce methane (natural gas) that can be reused to power the combustion engine.

(e) The revenues associated with the Standard Carbon technology relies on the costs of natural gas, CO_2, and electricity. In fact, Standard Carbon carefully analyzed these three (3) factors to determine the relationship between the cost of each and net revenue/ tonne CO_2 stored.

(f) The results showed that the effect of change in price of electricity significantly outweighs the effect of variation in the price of both natural gas and CO_2. Meaning, carbon pricing is not necessarily the most important factor in the transition to a renewable energy economy.

(g) TRL: 6-8

(h) PFD:



(i) The takeaway from this is that, in order for technologies, such as Standard Carbon, to gain more traction, governments and utility regulatory agencies need to create real-time electricity markets that enable energy storage technologies to take advantage of surplus electricity production, and thus purchase the electricity at low costs.

(j) Possible markets that could stand to gain from using this technology, include but are not limited to:

(i) Electricity Power Producers (Utilities)

(ii) Biogas plant CO_2 scrubbers

(iii) Commercial Boilers in NYC Multifamily buildings – A recently passed law has left New York City with one of the highest carbon tax rates in the world.

5.2 Electrochaea

(a) Electrochaea's technology enables the production of low-carbon intensity methane from CO_2 using a simple four (4) stage process.

(b) The demand for methane that is driving this technology comes from several sources:

(i) Mandates for decarbonization in the transportation industry (e.g., LCFS, RINs)

(ii) Tariff based programs that focus on biogenic CO_2 sources

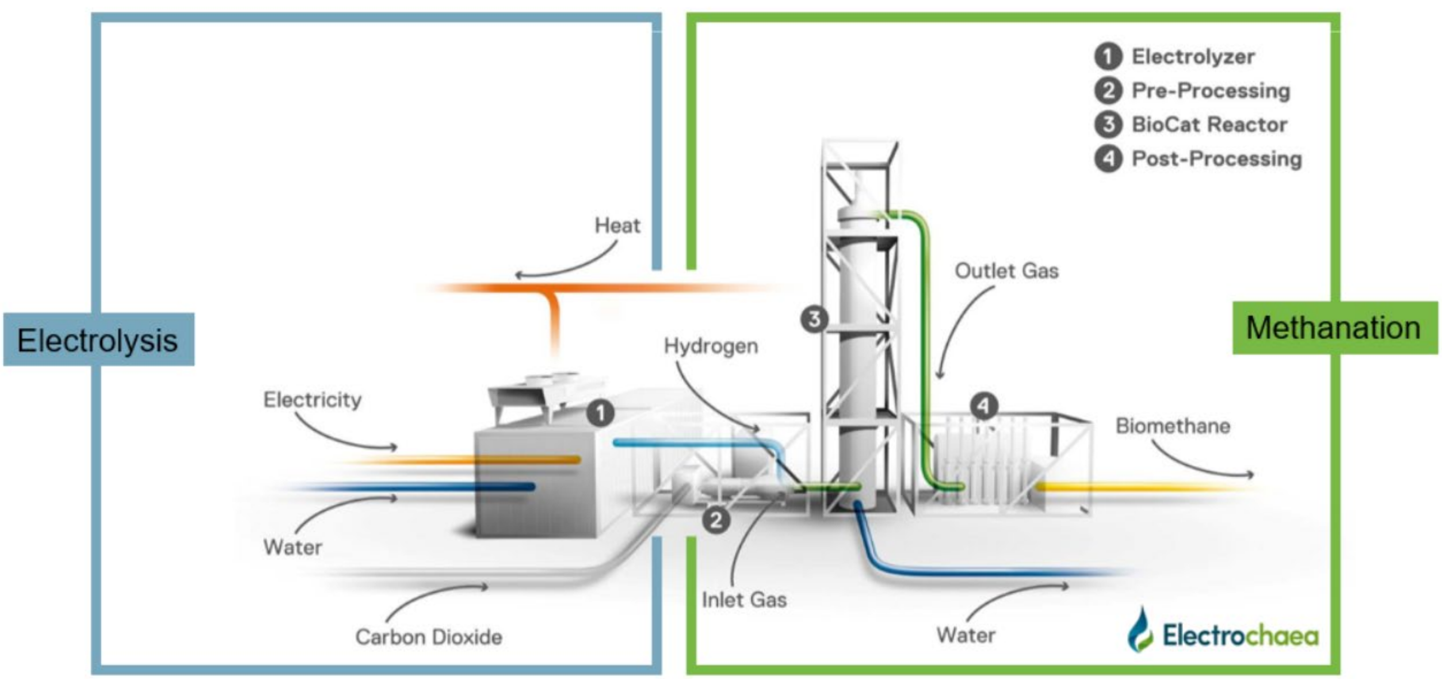
(iii) In the long term, future drivers could be long-duration storage and the continued pressure on "hard to decarbonize" industries to lower emission levels.

(iv) Electrochaea is meeting this demand with the following suppliers of CO_2:

- Organic waste and landfills
- Wastewater Treatment plants
- Ethanol production facilities

(c) Long term suppliers to this technology could potentially be various industrial companies producing cement, lime, steel etc.

(d) Electrochaea's Biomethanation technology can be broken into a simple four (4) stage process, as depicted in the figure below:



(e) This bio-methanation process is governed by two (2) simple equations:

$$\text{Electrolysis: Electricity} + 2H_2O \longrightarrow 2H_2 + O_2$$

$$\text{Methanation: } CO_2 + 4H_2 \longrightarrow CH_4 + 2H_2O$$

(f) Water is broken down into hydrogen via electrolysis in the first step. In the second step, that hydrogen is reacted with CO_2 to produce the desired methane product that can be reused at the plant.

(g) Electrochaea's technology has already been implemented at the industrial scale, in a number of instances. A few examples include:

(i) SoCalGas, NREL (0.25 MW_e) in Golden, Colorado, US

(ii) Store & Go (0.7 MW_e) in Solothurn, Switzerland

(iii) WWTP (1 MW_e) in Avedøre, Denmark

(h) The current scale of projects involving this technology is growing:

	PROJECT SIZE
Current	• Electrolyzer Range: 5-80 MW_e • Methane Production: 160-2500 SCFM
Emerging	• Electrolyzer Range: 10-150 MW_e • Methane Production: 310-5000 SCFM
Longer-term	• Electrolyzer Range: 100-200+ MW_e • Methane Production: 3100-6200+ SCFM

5.3 Noya

(a) While the previous two (2) companies used a point source method to capture CO_2, Noya uses a DAC method, in which CO_2 is captured directly from the atmosphere.

(b) Located in the US, Noya provides retrofit solutions to customers country wide by altering their cooling towers to be able to perform DAC.

(c) By Noya's estimates, cooling towers across the US would be able to capture 7 to 10 billion US tons of CO_2 per year if they were all fitted with the capture technology.

(d) Post capture, Noya's solutions can sequester, sell, or use the CO_2 to make new products. Noya handles the CO_2 captured by it's technology for the client, either selling it to a user of CO_2 or sequestering the CO_2 in a geological well owned by a partner.

(e) The ducting and capture equipment is added alongside the cooling tower and does not affect its operation in any way.

(f) Downstream of the cooling tower CO_2 processing equipment is introduced, which itself does not have a large physical footprint.

(g) Noya, shares the carbon credits generated through the capture and removal process so that customers can offset their building emissions.

(h) There are a number of utilization and storage methods Noya is investigating for post-capture of CO_2.

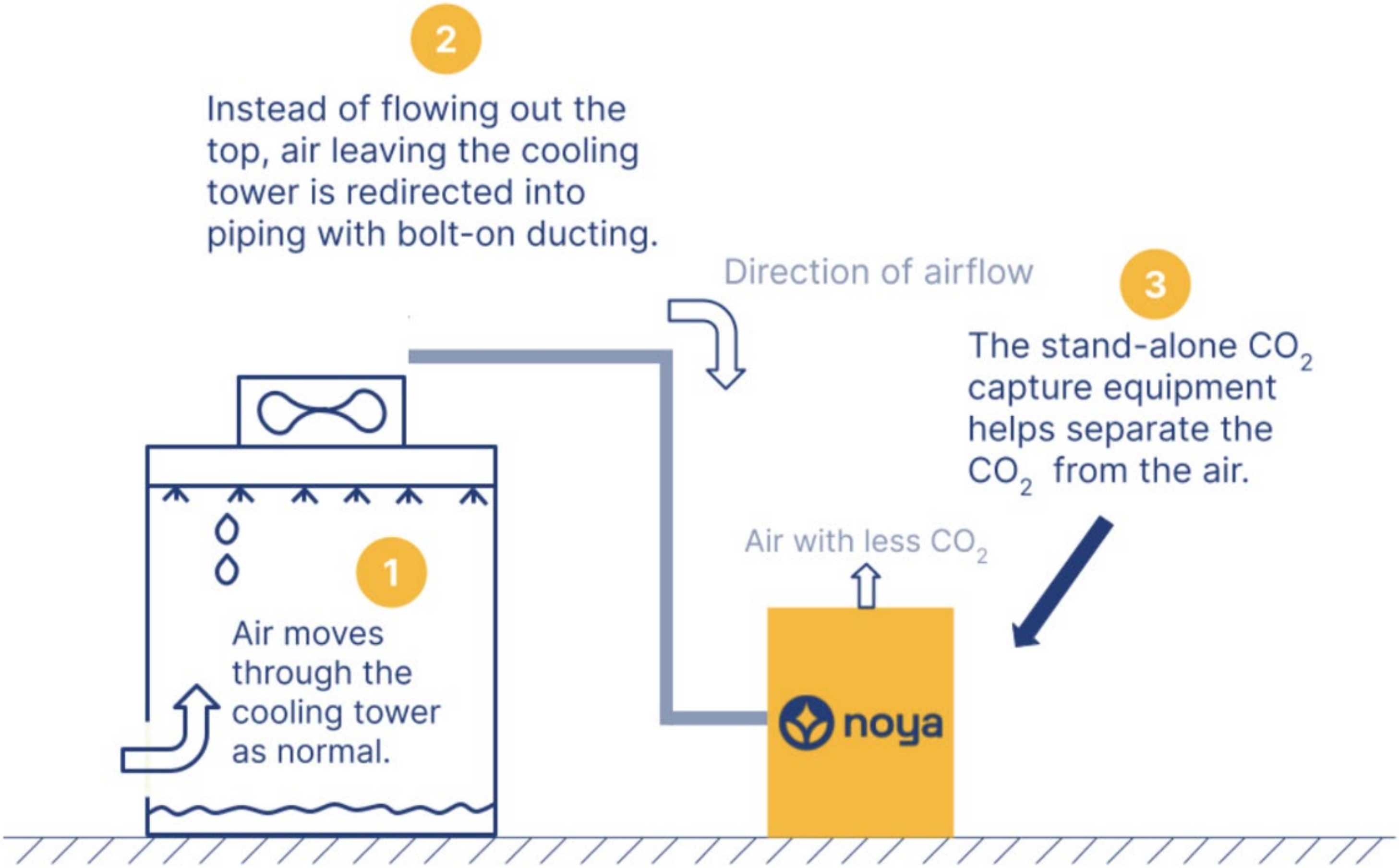
(i) While they work on developing their own sequestration technology, they are looking to partner with sequestration partners. Some of which include infusing the carbon into concrete or even the use of the carbon in depleted oil and gas reservoirs.

(j) There are already other companies in line to buy the CO_2 that Noya collects, many of which are also start-ups themselves and are looking to use CO_2 to develop products. A few examples include:

    (i) Aether Diamonds – Use CO_2 to manufacture diamonds

    (ii) Dimensional Energy and Prometheus Fuels – CO_2 is used to make synthetic fuels

(iii) Opus12 – Use CO_2 as a replacement for petrochemicals

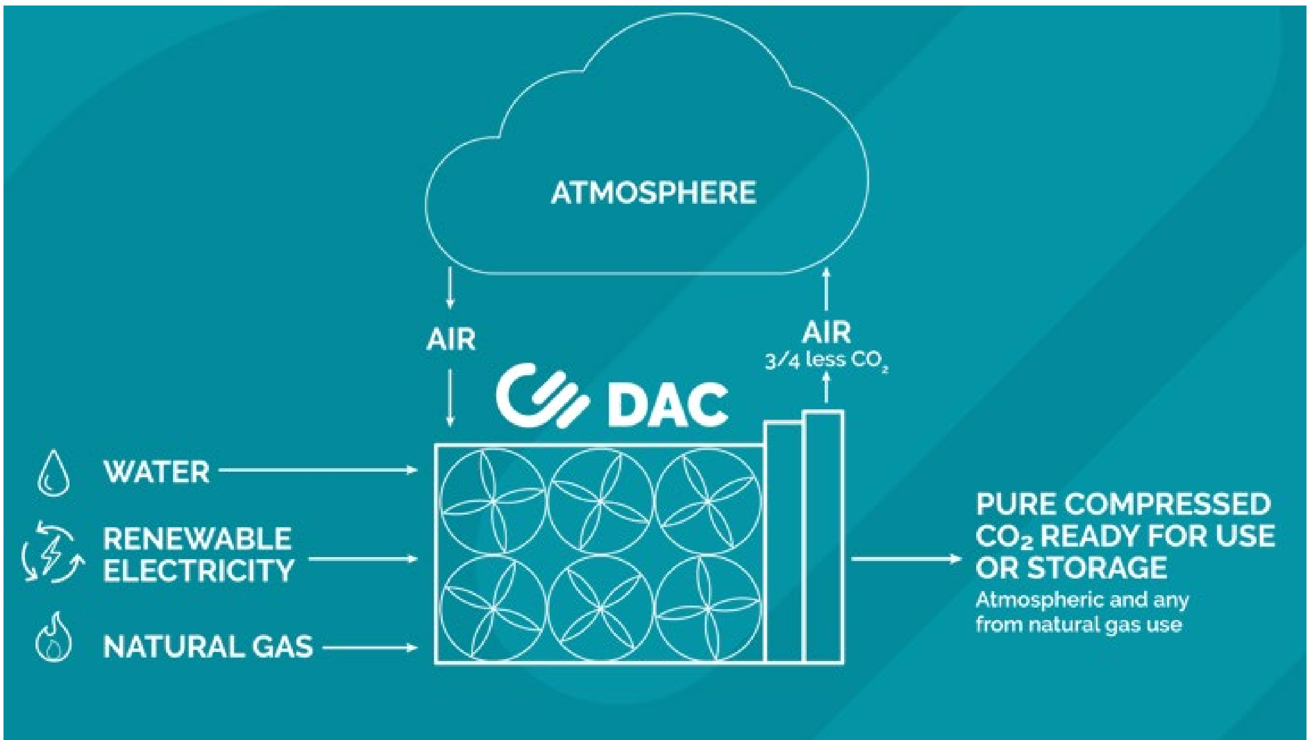


5.4 Carbon Engineering

(a) Similar to Noya, Carbon Engineering also uses the direct air capture method to capture CO_2 directly from the atmosphere.

(b) With a team and partners spread around the world Carbon Engineering is working to deploy Direct Air Capture facilities that capture one million tons of CO_2 per year, each.

(c) The technology pulls in air from the atmosphere via multiple fans. Once the air has been captured by the unit, a series of chemical reactions extracts the CO_2 from the air while returning the rest to the atmosphere. This is the same process trees carry out when they photosynthesize. The difference is this Direct Air Capture technology is faster, smaller and delivers the CO_2 in a pure, compressed form that can be stored or reused.



The inputs and outputs of CE's Direct Air Capture process

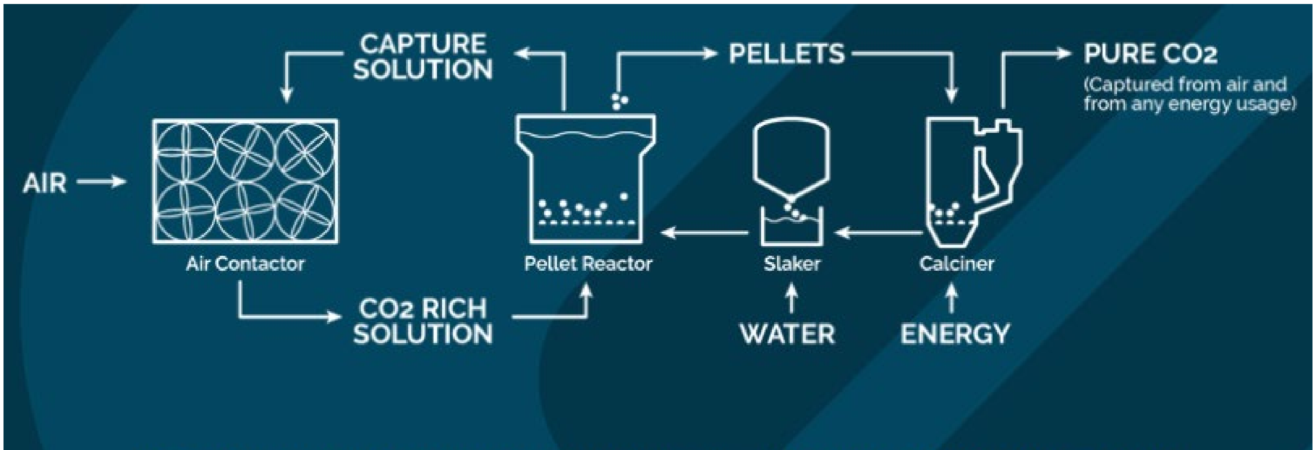
(d) A closer look at the technology reveals that there are four (4) main pieces of equipment involved in this DAC Technology:

(i) Air Contactor

(ii) Pellet Reactor

(iii) Calciner

(iv) Slaker



CE's Direct Air Capture process, showing the major unit operations - air contactor, pellet reactor, slaker, and calciner - which collectively capture, purify, and compress atmospheric CO_2

(e) The process begins with the **air contactor**, which is a large structure that looks similar to a cooling tower. A fan inside the structure will pull in air where it then passes over thin plastic surfaces that are covered in potassium hydroxide solution. This nontoxic solution binds with the CO_2 molecules, separating them from the rest of the air, and trapping them in the liquid solution in the form of a carbonate salt.

(f) The carbonate salt is then separated out of the solution into small pellets in the pellet reactor.

(g) These pellets then pass through the calciner where they are heated in order to release the CO_2 in pure gas form.

(h) With the CO_2 removed from the pellets, the pellets are hydrated in a slaker and recycled back into the system to reproduce the capture chemical used at the start of the process.

(i) After the pure CO_2 is captured, Carbon Engineering is exploring options to either store it permanently underground or use it to produce fuel.

(j) Carbon Engineering's, Air to Fuel plants, accomplish the latter. With hydrogen generation and fuel synthesis capability these plants are able to deliver near carbon neutral synthetic fuel.

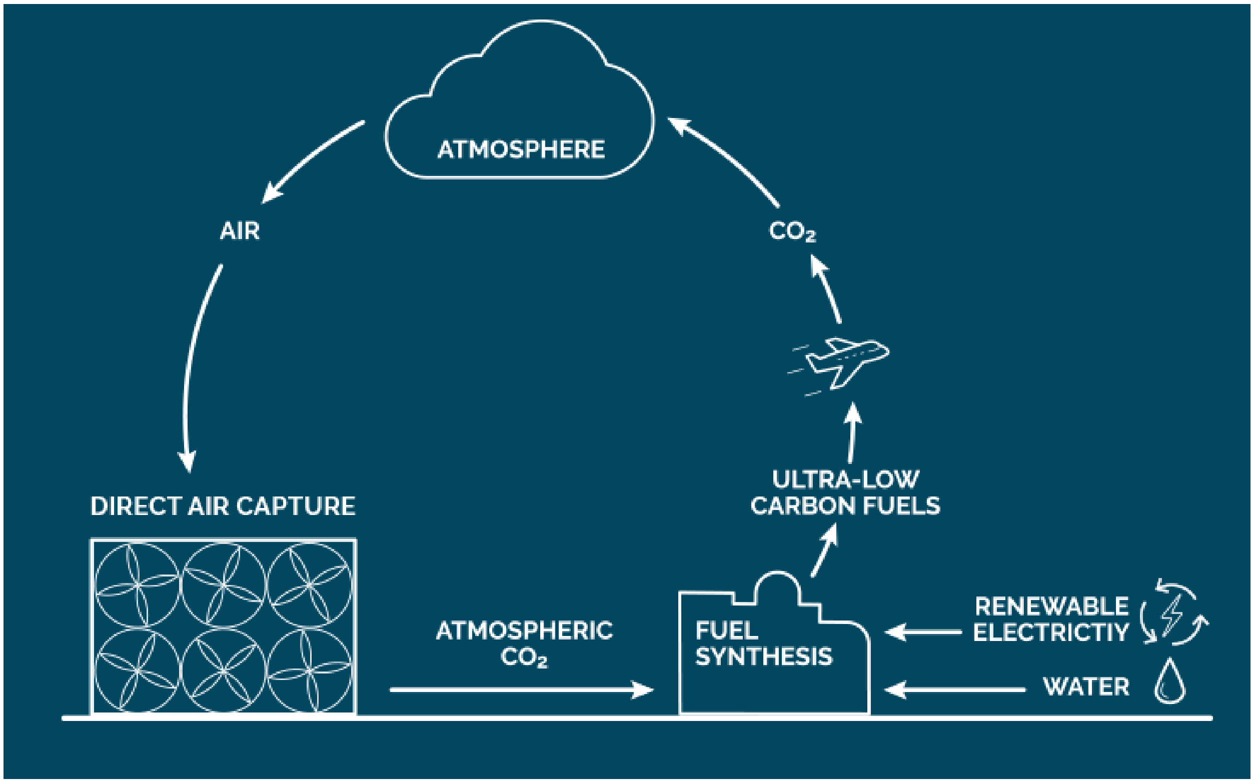
(k) At a typical Air to Fuel plant, the captured CO_2 is converted into synthetic crude oil that can then be processed into gasoline, diesel or jet fuel.

(l) The process can actually be broken down into three (3) simple steps:

  (i) Step 1 – Direct Air Capture process captures and extracts CO_2 from the atmosphere (as described above).

  (ii) Step 2 – Clean Electricity (such as electricity provided by solar means) electrolyzes the water, separating into hydrogen and oxygen.

(iii) Step 3 – The CO_2 and hydrogen are reacted to produce various hydrocarbons, which can directly, or with some refinement, be reworked into ready to use gasoline, diesel, or jet fuel.



5.5 LanzaTech

(a) LanzaTech's carbon recycling technology is focused on using bacteria to convert CO_2 emissions into various fuels and chemicals.

(b) The process of recycling the CO_2 emissions is circular:

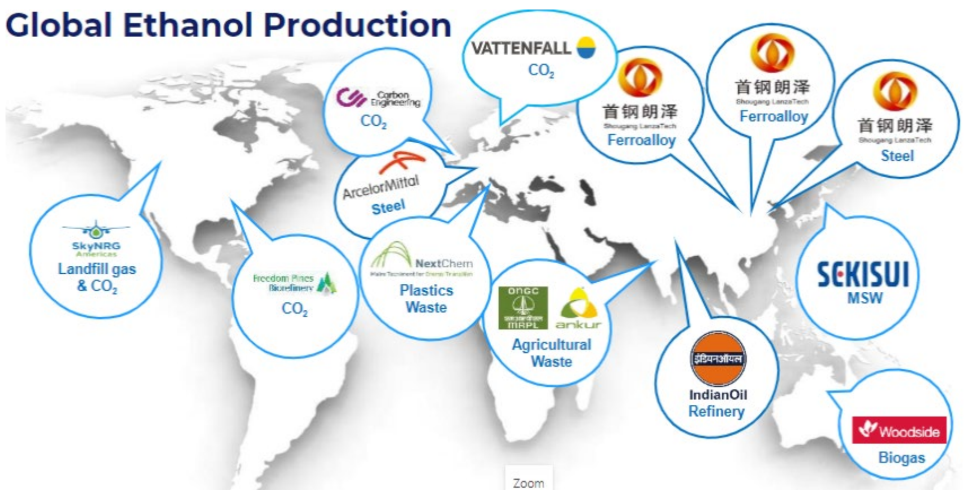
(c) The first commercial plant to implement this technology is a steel mill located in China and has been operating since 2018.

(d) Thus far the recycling process has been able to produce more than 100,000 tons of ethanol and has allowed for more than 150,000 tons of CO_2 emissions into the atmosphere to be avoided.

(e) There is also a second operational plant in China (operational since May 2021) that runs from Ferroalloy off-gas.

(f) The first commercial plant in Europe (Steel-off gases from Arcelor Mittal) is set to be operational sometime in 2022.

(g) LanzaTech has been able to implement their technology on a global scale. The following figure below depicts their ethanol production facilities worldwide:



(h) LanzaTech's technology has capabilities in producing a number of different chemicals including;

(i) Ethanol

(ii) Acetone

(iii) Isopropanol

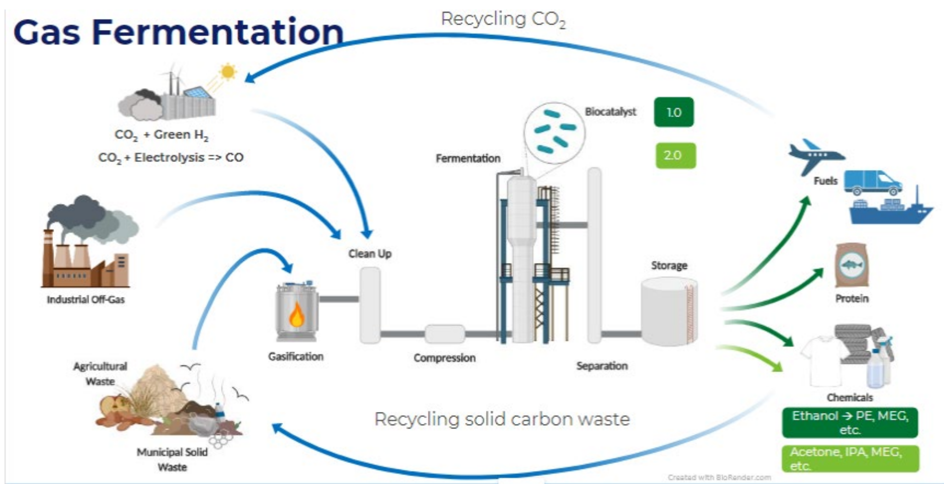
(iv) Monoethylene Glycol (MEG)

(i) The technology is also capable of using carbon emissions to produce sustainable aviation fuels

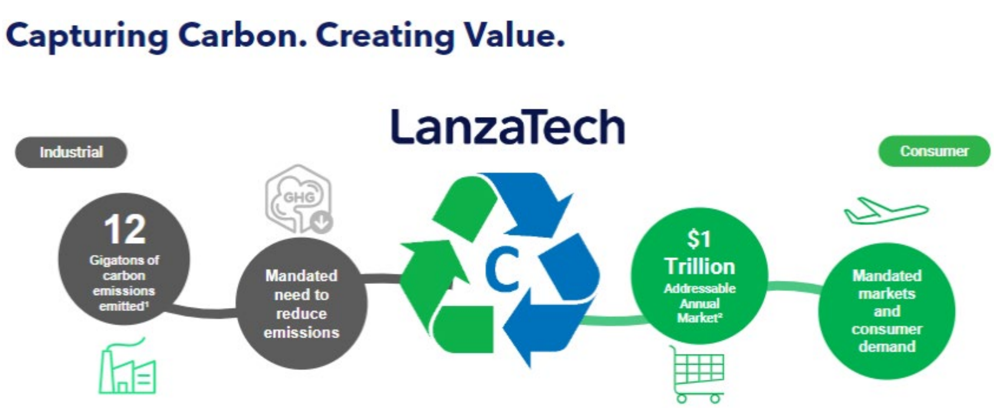
(j) These fuels are commercially tested, ASTM certified, and are a drop in replacement option.

(k) The diagram below helps give a better sense of the products that LanzaTech is currently able to make using their recycling process:

(l) While there is a great deal of people that believe carbon is the problem, LanzaTech looks at carbon as trillion-dollar opportunity.



(m) The business model is simple, effective, and green:



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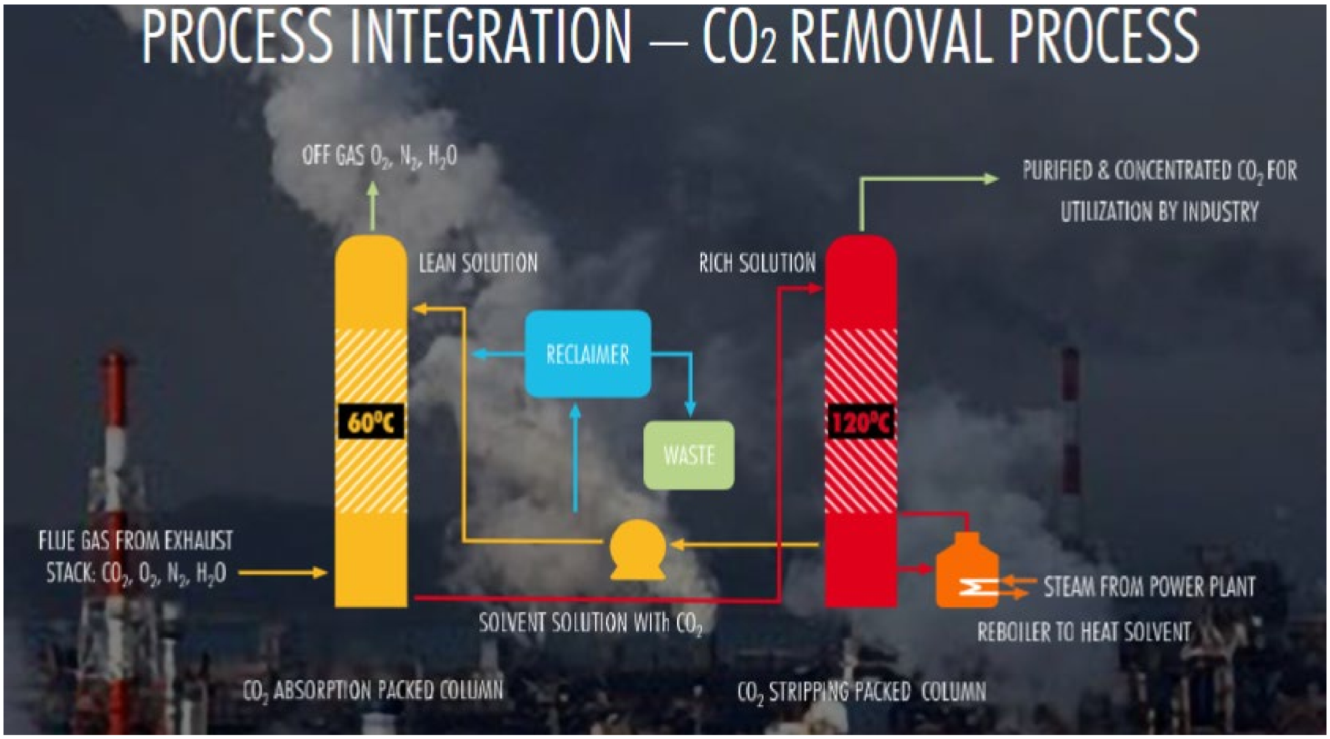
5.6 Delta Cleantech

(a) Delta Cleantech has been involved in over 50% of the major Carbon Capture initiatives and designs worldwide since its founding 10 years ago.

(b) The company works on a global scale in Canada, USA, Europe, UAE, Australia, and China.

(c) The basics of the technology that Delta uses can be depicted in the figure below:



(d) The technology that Delta offers can be further broken down in to six (6) subcategories:

(i) Delta Solvents – Solvents designed specifically to meet individual plant needs

(ii) Modular Design – Helps to reduce capital costs and manufacturing lead times during factory fabrication by utilizing standard parts

(iii) Process Design Optimization – Simulation algorithms yield higher accuracy and performance

(iv) Solvent Assurance – Purifies solvent to “Like new” quality, to renew peak operating performance

(v) Wash Section Integrations – Reduces emissions and capital costs

(vi) Delta Ops – Reducing operating costs and maximizing performance by commissioning the optimum plant operating protocols

(e) The solvent performance is key to the success of this technology. Delta's trademark DeltaSolv has been proven to offer significant performance enhancement in the following areas:

(i) Higher CO_2 absorption rate

(ii) Less corrosion

(iii) Lower density and viscosity

(iv) Lower heat of reaction

(f) All these factors contribute to the following cost reductions that Delta offers:

(i) Reduction in CAPEX by up to 40%

(ii) Reduction in OPEX by up to 30%

(g) Delta CleanTech also has their hand in hydrogen production.

(h) When it comes to hydrogen production, the landscape can be broken down into three (3) subcategories:

Current	2021-2030	2030-2050
Grey Hydrogen	Blue Hydrogen	Green Hydrogen
Split natural gas into hydrogen and CO_2	Split natural gas into hydrogen and CO_2	Split water into hydrogen by electrolysis powered by water or wind
CO_2 emitted into the atmosphere	CO_2 stored or reused	No CO_2 emitted

(i) Delta's business approach from 2021 to 2030 is going to be to integrate their LCDesign, Carbon Capture into existing grey hydrogen plants to convert them into blue hydrogen plants. On top of that they plan to help newly installed blue hydrogen plants with the capture of CO_2.

(j) Natural gas decomposition coupled with carbon capture is the most economical and green solution to hydrogen production for the foreseeable future according to Delta.

(k) CO_2 footprint of blue hydrogen: 0.82-1.12 kg of CO_2 eq./kg H_2

(l) CO_2 footprint of hydrogen produced via electrolysis with wind/solar electricity sources: 0.92-1.13 kg CO_2 eq./kg H_2

(m) Delta Cleantech produces food grade CO_2 for utilization in the existing CO2 markets (i.e., for greenhouses, breweries, soda manufacturers, packaged food producers, etc.).

(n) Delta Cleantech actually combined their capture technology with the utilization technology of a few of the Carbon XPrize finalists at a natural gas power plant in Alberta to help determine the winner of the XPrize. Finalists that worked with Delta Cleantech included:

(i) CUT – Graphene products

(ii) CERT – Advanced bio plastics

(iii) Carbon Corp

(iv) Air Co. – Ethanol Production

(v) Carbon Cure – Building Materials

(o) It was announced, in April 2021, that Carbon Cure are one of two winners of the competition and will receive significant funding to advance their technology.

Please refer to Appendix B for the list of references used in this section of the report.

6/ SWOT ANALYSIS

6.1 Strengths

(a) Carbon Capture does not require significant changes to the existing energy production infrastructure for users of natural gas.

(b) Carbon Capture is also fuel and application agnostic, meaning that CO_2 can be captured from various fossil fuel users (e.g., GTGs, boilers, ICEs, Process Dryers) using various fossil fuels (e.g., natural gas, fuel oil, coal).

(c) In the U.S., there are significant Federal Government incentives for the application of Carbon Capture technology, specifically the 45Q enhancement in the recently enacted Inflation Reduction Act in the U.S. will increase to $60/tonne for utilization of CO_2 from industrial boiler plants. In fact, the IRA allows for a direct payment option for receiving this credit.

(d) In Canada, a rising Carbon Tax acts as an economic driver to reduce CO_2 by any means, including Carbon Capture (see Section 2.9).

(e) An established CO_2 market does exist, which justifies a not-insignificant economic value for captured CO_2 (that is, Food Grade CO_2, which is roughly 99.99% pure CO_2, selling for 80-130 USD/tonne). This can be a significant incremental revenue stream to the project.

(f) Some sectors have limited options to reduce CO_2 emissions attributable to their processes. Carbon Capture is a solution for those “hard-to-abate” industries.

(g) Carbon Capture has been a viable, and demonstrated technology, for decades in the Oil & Gas industry (for natural gas sweetening). The demonstration of the second/third generations of this technology is taking place now and will increase the availability and reliability of this technology in the near future.

6.2 Weaknesses

(a) The CCUS industry is in the "Early Adopter" stage for deployment of small to medium scale Carbon Capture systems (that is 10 TPD-100 TPD). Therefore, there is a higher cost for entry at this point in time.

(b) This is largely a function of CO_2 concentration and volume, which at small scale, results in increased cost to capture CO_2.

(c) The Public Relations (PR) value of Carbon Capture systems is politicized. We perceive that this issue will be greater in Canada than it will be in the U.S.

(d) The technology can be polarizing, especially when compared with the adoption of Variable Renewable Energy (VRE) technologies.

(e) Newer Carbon Capture technologies are rapidly developing, and within the next 5 years, these technologies will likely outperform current mature technologies (i.e., Chemical Absorption), from both a technical and economic perspective. This can be a risk to early adopters if they are looking for the most economical solution to achieve substantial decarbonization in the next 5 years (i.e., meeting 2030 commitments).

(f) CCU can be space intensive.

(g) The amine-based solvent can be perceived to be a risk to the industrial, especially if it leaks. This concern/objection must be understood clearly by the Local Distribution Company (LDC) representative.

(h) Although storage in permanent aquifers is much more straightforward than utilization of captured CO_2, the approvals required will be very lengthy in both countries, but especially in Canada due to extensive consultations required with land owners, the public, Indigenous groups, as well as the Federal and Provincial governments.

6.3 Opportunities

(a) In the absence of adequate geology for long-term sequestration of CO_2 in saline aquifers, a Carbon Capture system has the potential to be a market participant in the "circular economy" where CO_2 can be exchanged as a commodity.

(b) Since Carbon Capture technology is ready for deployment now and is able to "bolt-on" to existing infrastructure, it is possible for fossil fuel consumers to decarbonize their process(es) before their competitors.

(c) Focusing on utilization of captured CO_2 will allow those organizations which deploy Carbon Capture systems to generate a new, relatively stable, revenue stream.

(d) Carbon Capture is one of the few technologies which make "carbon negative" projects possible, just by combining a switch from fossil fuels to, say biofuels (i.e., RNG or biomass), and adding Carbon Capture to "the back end".

(e) There is a market in North America for Food Grade CO_2 post-COVID. The conventional suppliers of CO_2 seem to be having a hard time fulfilling their contractual obligations.

(f) For those customers who need CO_2 to produce a saleable product, and who are at risk from big name suppliers not fulfilling contractual obligations, CCU offers a way to secure the supply of CO_2.

6.4 Threats

(a) Capturing CO_2 from the flue gas streams could have a material impact on the composition of the flue gasses.

(i) The reduction of CO_2 in flue gases (up to 12% of the flue gas volume) will impact the compliance of boilers, ICEs, and GTGs which are governed by volume-based environmental regulations.

(ii) A volume-based standard (measured in ppm or other) will be skewed negatively for CO_2-depleted flue gas streams, as their concentration will appear to have increased, even though the net mass of contaminant emitted to the environment is constant.

(iii) Government bodies which administer these regulations may not be amenable to altering the volume-based regulations, resulting in reduced uptake of CCUS technologies.

(b) Depending on the regulations in place, and dependent on the jurisdiction, this could cause issues with air pollution limits (i.e., NO_X and SO_X emissions, if the limits are volume based and not fuel/energy based).

(c) "NIMBYism" (Not In My Backyard) could cause changes to existing legislation, or prompt new regulations, to limit/prohibit Carbon Capture activities (or at least utilization and storage activities).

(d) In the U.S., the tax credits currently available are only available for the first 12 years of the Carbon Capture project's lifetime.

(i) After this point, if CO_2 is not utilized (i.e., does not have an economic value in the market), then the cash flow for the Carbon Capture project is negative.

(ii) It is crucial, therefore, that utilization be considered, to ensure that 10-, 15-, and 20-year NPV's are positive.

(e) Whether it is a tax credit in the U.S., or a carbon tax in Canada, there is still a threat that a future government will overturn previous legislation, when in fact it was the tax credit, or the carbon tax, which gave the business case certainty. Installing CCU is still a response to federal leadership, which is, at the end of the day, some "regulatory risk".

7/ CASE STUDY – COMBUSTION GAS TURBINE GENERATOR

7.1 Equipment Specifications

PARAMETER	UNIT	VALUE
Net Electrical Output Rating	kWe	4,863
Unfired Thermal Output Rating	kpph	30
Fired Thermal Output Rating	kpph	N/A
Fuel Input Energy (LHV)	mmBtu/hr	57
CO_2 in Exhaust Gas	%, by volume	5
CO_2 Production	tonnes/year	24,340

7.2 Technical Assumptions of CCU System

PARAMETER	UNIT	VALUE
Incremental Steam Energy Required	mmBtu/tonne CO_2	2.9
Natural Gas Boiler Efficiency	% (HHV)	80
Incremental Natural Gas Required	mmBtu/tonne CO_2	3.6
Yearly Operating Hours	hrs	8,000
CO_2 Capture Rate	tonnes/day	80
Annual CO_2 Capture Rate	tonnes/year	24,340
Incremental Natural Gas Emissions Attributable to Steam Production	tonnes/year	4,675
Net CO_2 Reduction	tonnes/year	19,665

7.3 Financial Assumptions

PARAMETER	UNIT	VALUE
Purchase Price of Electricity	$/kW.h	0.10
Burner Tip Cost of Natural Gas	$/mmBtu	6
Annual Maintenance Rate	% Of CAPEX	0.5
Location	-	United States
Project Start Year	-	2026
Carbon Price / Tax Credit	$/tonne	60
Value of Sold Carbon (Assuming utilization opposed to storage)	$/tonne	40

7.4 Proforma Business Case Analysis

#	METRIC	$000'S
1	CARBON TAX SAVINGS / CARBON CREDIT	1,464
2	REVENUE FROM CO_2 SALES (IF APPLICABLE)	974
3	**TOTAL INCREMENTAL ANNUAL SAVINGS**	**2,438**
4	STEAM USAGE	641
5	ELECTRICITY USAGE	82
6	ANNUAL MAINTENANCE	100
7	**TOTAL INCREMENTAL ANNUAL OPERATIONAL EXPENSES**	**823**
8	**NET ANNUAL SAVINGS (BEFORE TAX, BEFORE FINANCING)**	**1,615**
9	CAPITAL COST (DESIGN, SUPPLY, INSTALL, COMMISSION)	20,040
10	**SIMPLE PAYBACK (YEARS)**	**12.4**
11	15 YEAR NPV ($000'S)	7,837

7.5 Implementation Considerations

(a) The concentration of CO_2 in the GTG flue gas (5%) is lower than that of a boiler (13%) or an ICE (10%).

   (i) While most Carbon Capture systems can capture CO_2 at concentration as low as 3%, it may require a Carbon Capture system to be overdesigned (higher nameplate capacity).

   (ii) This results in either (or both) higher CAPEX and higher energy demand (often in the form of steam) to capture that CO_2.

(b) For Chemical Absorption Carbon Capture systems, thermal energy is required to release CO_2 from the amine solvent.

   (i) For GTG systems, there may or may not be adequate steam production on-site (which is currently not being fully utilized) to supply the Carbon Capture system.

(c) The flue gas must be cooled before entering the Carbon Capture system (or cooled at the front end of the Carbon Capture system).

   (i) The cooling demand for the Carbon Capture system will change based on the GTG configuration (e.g., GTG with HRSG vs. GTG without HRSG).

7.6 Challenges

(a) In this particular case, and in this particular jurisdiction (Canada), this GTG will be operated less than 8,000 hours a year and will likely be moving to more sporadic operation (~250-500 hours a year). Capturing the daily, or even yearly, rate of CO_2 will therefore be a challenge as emissions decrease as a function of operating hours.

(b) The flue gas of the GTG system will have to be cooled considerably, and scrubbed for contaminants, prior to entering the Carbon Capture system. Depending on the Heat Recovery systems installed with the GTG, this could represent an increase in CAPEX.

8/ CASE STUDY – WATER TUBE BOILER

8.1 Equipment Specifications

PARAMETER	UNIT	VALUE
Net Thermal Output Rating	kpph	250
Steam Temperature	°F	600
Steam Pressure	Psig	400
Max Fuel Input Energy (HHV)	mmBtu/hr	315
Actual Fuel Input Energy (HHV)	mmBtu/hr	145
CO_2 in Exhaust Gas	%, by volume	13
CO_2 Production	tonnes/year	61,000

8.2 Technical Assumptions

PARAMETER	UNIT	VALUE
Incremental Steam Energy Required	mmBtu/tonne CO_2	3.1
Natural Gas Boiler Efficiency	% (HHV)	80
Incremental Natural Gas Required	mmBtu/tonne CO_2	3.9
Yearly Operating Hours	hrs	8,000
CO_2 Capture Rate	tonnes/day	200
Annual CO_2 Capture Rate	tonnes/year	61,000
Incremental Natural Gas Emissions Attributable to Incremental Steam Production	tonnes/year	14,200
Net CO_2 Reduction	tonnes/year	46,800

8.3 Financial Assumptions

PARAMETER	UNIT	VALUE
Purchase Price of Electricity	$/kW.h	0.10
Burner Tip Cost of Natural Gas	$/mmBtu	6
Annual Maintenance Rate	% Of CAPEX	0.5
Location	-	United States
Project Start Year	-	2026
Carbon Price / Tax Credit	$/tonne	60
Value of Sold Carbon (Assuming utilization opposed to storage)	$/tonne	20

8.4 Proforma Business Case Analysis

#	METRIC	$000'S
1	CARBON TAX SAVINGS / CARBON CREDIT	3,699
2	REVENUE FROM CO_2 SALES (IF APPLICABLE)	1,230
3	**TOTAL INCREMENTAL ANNUAL SAVINGS**	**4,929**
4	STEAM USAGE	1,619
5	ELECTRICITY USAGE	207
6	ANNUAL MAINTENANCE	192
7	**TOTAL INCREMENTAL ANNUAL OPERATIONAL EXPENSES**	**2,017**
8	**NET ANNUAL SAVINGS (BEFORE TAX, BEFORE FINANCING)**	**2,912**
9	CAPITAL COST (DESIGN, SUPPLY, INSTALL, COMMISSION)	38,337
10	**SIMPLE PAYBACK (YEARS)**	**13.2**
11	15 YEAR NPV ($000'S)	5,027

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8.5 Implementation Considerations

(a) The boiler may not operate at full load for 8,000 hours a year, and therefore, will not produce consistent quantities of CO_2 throughout the year.

(i) Carbon Capture systems should be sized to capture the "baseload" level of CO_2 emissions from these systems to avoid equipment oversizing (and thus CAPEX).

(b) While this case study is for a natural gas fired boiler, other fuels (such as fuel oil or coal) may be used instead of natural gas.

(i) The emissions profile for other fuels will be different, both from a CO_2 production perspective, and from an air pollutant perspective (i.e., NO_X, SO_X, PM).

(ii) It is possible that additional air pollution controls will be required prior to entering the Carbon Capture System.

(c) The flue gas must be cooled before entering the Carbon Capture system (or cooled at the front end of the Carbon Capture system).

8.6 Challenges

(a) Construction of the CCU system, is not straightforward, specifically, breaking into the stack such that the flue gases can be removed via an ID fan. This will involve taking the border down for several days, at least.

(b) A CCU system takes up space, and in some cases a considerable amount of space. Not only does the Carbon Capture system take up space, but so does the storage of captured CO_2, such that the CO_2 can be either utilized or stored underground at a future date.

(c) Another challenge is cooling the CO_2/flue gas to the target temperature. Is there cooling capacity available on site?

(d) The proponent of the CCU system should be mindful of the existing air permit, and specifically how emissions of NO_X are measured in the air permit. If the NO_X limit is expressed in weight of NO_X/MMBtu of fuel burned, then that is not a concern. But if the NO_X limit is expressed in ppm by volume of NO_2 expressed at 3% O_2, for example, then the air permit might need to be reviewed.

9/ CASE STUDY – LARGE INTERNAL COMBUSTION ENGINE GENERATOR

9.1 Equipment Specifications

PARAMETER	UNIT	VALUE
Net Electrical Output Rating	kWe	3,234
Fuel Input Energy (HHV)	mmBtu/hr	25
CO_2 in Exhaust Gas	%, by volume	11
CO_2 Production	tonnes/year	10,650

9.2 Technical Assumptions

PARAMETER	UNIT	VALUE
Incremental Steam Energy Required	mmBtu/tonne CO_2	2.9
Natural Gas Boiler Efficiency	% (HHV)	80
Incremental Natural Gas Required	mmBtu/tonne CO_2	3.6
Yearly Operating Hours	hrs	8,000
CO_2 Capture Rate	tonnes/day	35
Annual CO_2 Capture Rate	tonnes/year	10,650
Incremental Natural Gas Emissions Attributable to Steam Production	tonnes/year	2,500
Net CO_2 Reduction	tonnes/year	8,150

9.3 Financial Assumptions

PARAMETER	UNIT	VALUE
Purchase Price of Electricity	$/kW.h	0.10
Burner Tip Cost of Natural Gas	$/mmBtu	6
Annual Maintenance Rate	% Of CAPEX	0.5
Location	-	Canada
Project Start Year	-	2026
Carbon Price / Tax Credit	$/tonne	110
Value of Sold Carbon (Assuming utilization opposed to storage)	$/tonne	0

9.4 Proforma Business Case Analysis

#	METRIC	$000'S
1	CARBON TAX SAVINGS / CARBON CREDIT	1,171
2	REVENUE FROM CO_2 SALES (IF APPLICABLE)	0
3	**TOTAL INCREMENTAL ANNUAL SAVINGS**	**1,171**
4	STEAM USAGE	280
5	ELECTRICITY USAGE	36
6	ANNUAL MAINTENANCE	39
7	**TOTAL INCREMENTAL ANNUAL OPERATIONAL EXPENSES**	**355**
8	**NET ANNUAL SAVINGS (BEFORE TAX, BEFORE FINANCING)**	**816**
9	CAPITAL COST (INCLUDES 50% OF CAPEX INVESTMENT TAX CREDIT) (DESIGN, SUPPLY, INSTALL, COMMISSION)	7,735
10	**SIMPLE PAYBACK (YEARS)**	**9.5**
11	15 YEAR NPV ($000'S)	6,124

9.5 Implementation Considerations

(a) For this case study in particular, the ICE does not necessarily operate 8,000 hours a year.

(i) The sizing of the Carbon Capture system is more difficult for these systems as a decision must be made on the trade-off between optimizing CAPEX and CO_2 emissions reduced.

(ii) In other words, does the Carbon Capture system capture all the peak CO_2 emissions (i.e., when the ICE is running full load and when operating at part load) or does the Carbon Capture system capture the "baseload" amount of CO_2 emissions.

(b) Absent any waste heat recovery, or on-site boilers, the availability of steam for the Carbon Capture system could be a barrier to adoption for ICE systems.

(c) The flue gas must be cooled before entering the Carbon Capture system (or cooled at the front end of the Carbon Capture system).

9.6 Challenges

(a) Projects which capture, and therefore sell/utilize, smaller amounts of CO_2 have less attractive economics as the CAPEX for CCUS systems are not yet optimized at small scale.

10/ CASE STUDY – INDUSTRIAL PROCESS USER (PRODUCT DRYER)

10.1 Equipment Specifications

PARAMETER	UNIT	VALUE
Evaporation Rate (Water Removed)	pph	32,000
Regenerative Thermal Oxidizer (RTO) Exhaust Flow Rate	acfm	38,000
Fuel Input Energy (HHV)	mmBtu/hr	45
CO_2 in Exhaust Gas	%, by volume	10
CO_2 Production	tonnes/year	16,750

10.2 Technical Assumptions

PARAMETER	UNIT	VALUE
Incremental Steam Energy Required	mmBtu/tonne CO_2	2.9
Natural Gas Boiler Efficiency	% (HHV)	80
Incremental Natural Gas Required	mmBtu/tonne CO_2	3.6
Yearly Operating Hours	hrs	8,000
CO_2 Capture Rate	tonnes/day	145
Annual CO_2 Capture Rate	tonnes/year	21,200
Incremental Natural Gas Emissions Attributable to Steam Production	tonnes/year	4,500
Net CO_2 Reduction	tonnes/year	16,750

10.3 Financial Assumptions

PARAMETER	UNIT	VALUE
Purchase Price of Electricity	$/kW.h	0.10
Burner Tip Cost of Natural Gas	$/mmBtu	6
Annual Maintenance Rate	% Of CAPEX	0.5
Location	-	Canada
Project Start Year	-	2026
Carbon Price / Tax Credit	$/tonne	110
Value of Sold Carbon (Assuming utilization opposed to storage)	$/tonne	0

10.4 Proforma Business Case Analysis

#	METRIC	$000'S
1	CARBON TAX SAVINGS / CARBON CREDIT	1,842
2	REVENUE FROM CO_2 SALES (IF APPLICABLE)	0
3	**TOTAL INCREMENTAL ANNUAL SAVINGS**	**1,842**
4	STEAM USAGE	502
5	ELECTRICITY USAGE	71
6	ANNUAL MAINTENANCE	58
7	**TOTAL INCREMENTAL ANNUAL OPERATIONAL EXPENSES**	**632**
8	**NET ANNUAL SAVINGS (BEFORE TAX, BEFORE FINANCING)**	**1,210**
9	CAPITAL COST (INCLUDES 50% OF CAPEX INVESTMENT TAX CREDIT) (DESIGN, SUPPLY, INSTALL, COMMISSION)	11,638
10	**SIMPLE PAYBACK (YEARS)**	**9.6**
11	15 YEAR NPV ($000'S)	8,567

10.5 Implementation Considerations

(a) CO_2 capture is a function of that process operating, which can vary from application to application

(b) In this case, a natural gas fired dryer is used to produce a dried solid product. The wet solid product is produced intermittently depending on the market dynamics (related to the sale of a wet or dry version of the product).

  (i) "Sudden" changes in operation (i.e., from day to day) can reduce the yearly performance of a Carbon Capture system.

  (ii) For example, a Carbon Capture system rated for 145 tonnes per day, but only operates ~150 days a year instead of 300 days a year, is technically only operating at 50% of yearly capacity.

(c) Steam, or another higher-grade heat source, is required for the Carbon Capture system.

  (i) If this is not currently produced on-site, then additional steam producing equipment would be required which <u>could</u> produce additional CO_2 and reduce the impact of a Carbon Capture system.

(d) The flue gas must be cooled before entering the Carbon Capture system (or cooled at the front end of the Carbon Capture system).

10.6 Challenges

(a) Indirect natural gas fired dryers will have a different CO_2 concentration compared to a direct fired dryer, primarily because of the addition of moisture from the drying process.

(b) If the solid being dried, via an indirect dryer for example, emits Volatile Organic Compounds (VOCs) or other chemicals species, then additional pollution control mechanisms will be required.

  (i) VOCs or chemicals added to the flue gas stream could potentially contaminant the solvent in the Carbon Capture system.

11/ CCU TRAINING FOR LDC REPS

11.1 Target Clients

(a) CEM suggests that each LDC start with a small CCU project which would have low CAPEX and relatively low risk, but which would enable the LDC to promote the project aggressively and be perceived as being in the CCU business.

(b) Toward that end, in terms of enough CO_2 in the flue gases to capture, CEM suggests if the goal is a 10-tonne per day project and the customer wanted to displace a lot of CO_2, the minimum size would be a customer now consuming at least 70,000 MCF (726,000 therms) of natural gas.

(c) If, on the other hand, a customer wanted to show that they were doing something on CO_2 capture, but not be too intrusive, then a project with a customer now consuming roughly 560,000 MCF per year is recommended.

(d) CEM also suggests that the initial target client be close to a user of food-grade CO_2 or close to a very large vegetable greenhouse, such that the transportation from captured CO_2 to the user of CO_2 is short.

(e) Another obvious initial target client would be a large producer of CO_2 which also uses CO_2 to make its saleable product, such as a food and beverage plant and especially a brewery.

(f) Another outstanding target client would be someone who is close to a permanent aquifer, where instead of utilization of captured carbon, captured carbon could be stored deep in the ground, if this were permissible.

(g) Another thing to look for would be space around the stack, since the CCU equipment does take up space.

(h) Another key requirement is strong proponents both at the local level as well as in head office.

(i) Another key criterion for an initial target client would be a customer who wants to be perceived either by senior leadership or by their own clients as being green and stewardly.

(j) On the practical side, another consideration is cheap electricity and excess steam available since low-cost electricity and some steam generation capacity is required for both the modular amine systems as well as the more traditional amine systems.

11.2 How to Educate LDC Customers

(a) Prepare a two-page PDF which contains clear features and benefits of CCU and a strong hook with respect to the role that the LDC can play in facilitating the development of the CCU system.

(b) Prepare a clear, simple, concise presentation for LDC representatives to give to their customers in initial client meetings.

(c) Prepare several (three (3) to five (5)) one-page case studies so that possible objections can be "countered with proof" during client meetings.

(d) Use an E-mail Blast (eblast) to all contract clients to get them thinking about CCU and inviting them to take the first step, either in terms of having the LDC representative at a site visit or, alternatively, attending a large-volume customer meeting.

(e) Invite all large-volume customers to a technology transfer session for half a day, introduce CCU technology, and have a number of guest speakers, specifically, OEMs as well as some early adopter customers.

(f) Have several OEMs make presentations to customers who want to get more deeply into the specifics of the technology.

(g) Have a simple business case prepared in Excel, such that LDC representatives can talk to customers about the business case.

(h) Educate at least one (1) person within each LDC, such that this individual could do some screening analysis and support front-line representatives in looking at the technical and financial feasibility at the "proof-of-concept" assessment stage.

(i) Undertake one (1) pilot demo project so that customers can see a CCU system in operation and get familiar with the technology. In so doing, prospective customers would not have to travel to other countries to see the technology.

(j) Develop some kind of program, whether it is financial incentives, joint venture participation, or outright offering CCU as a service behind the meter, such that LDC's commitment to CCU is crystal-clear in the clients' minds.

(k) Ensure that the LDC representatives are very familiar with the 45Q tax credit. For example, see: carbon-capture-provisions-ira.pdf (catf.us)

11.3 Pre-Meeting Site Data Questionnaire for LDC Representatives

CEM QUESTIONS	UNITS	LDC RESPONSE
1. What equipment now consumes natural gas?		
(a) Fire-tube boiler		
(b) Watertube boiler		
(c) ICE		
(d) Combustion GTG		
2. Maximum capacity of this equipment?	mmBTU/hour	
3. How much natural gas does this equipment normally consume?		
(a) Average consumption		
(b) Low consumption		
(c) High consumption		
4. Diameter of stack		
5. Height of stack		
6. Is there electricity available?		
7. Is there steam capacity available?		
8. Are there any other fossil fuels used at the site, such as coal, Heavy Fuel Oil (HFO), Light Fuel Oil (LFO), or propane?		
9. Average natural gas used by the site per day?		
10. Operation of the plant?	Days/year	
11. Hours/day of natural gas utilization?		
12. Is there space available around the stacks?		
13. Delivery cost of electricity presently?	Cents/kWh	
14. Burner tip cost of natural gas presently?		
15. Resources available to operate and maintain CCU systems?		

11.4 Questions LDC Representatives Might Get Asked (FAQ)

(a) **What is the ideal temperature and pressure of the flue gases from which the CO_2 will be captured?**

(i) This varies depending on the solvent used in a conventional amine Carbon Capture system, but is in the range of 100-150 F and anywhere from 15-70 psig (to be verified during preliminary engineering, given that this will differ for each OEM). Other capture technologies may require higher temperatures or pressures (e.g., membrane technologies mostly have CO_2 passing through the membrane which reduces pressure of the captured stream).

(b) **How clean must the flue gas be for this system to work?**

(i) The flue gas must be clear of any PM and have limited concentrations of NOX and SOX (i.e., best to capture at the stack, once emission controls have been applied).

(c) **Is cooler flue gas better for the effective operation of the CCU system?**

(i) Yes, flue gas must be cooled prior to entering a conventional amine system; some systems have integrated flue gas coolers that are integrated with the heating component of the Carbon Capture system. Other capture technologies may not require significant cooling.

(d) **What if the air mass flow rate and the pressure of the flue gases vary considerably in any given hour?**

(i) For a conventional amine system, the air mass flow rate may not materially impact the operation of the CCU system. The system would simply be operating a % of its rated capacity. The pressure will need to be maintained, either via a fan or compressor system, depending on the exact OEM solution installed.

(e) **What is the amine solution, which is so vital to the CCU system?**

(i) The amine is a solvent, which is nitrogen based, used to preferentially absorb CO_2 from the flue gasses. The solvent does this by chemically reacting with the CO_2 to form a CO_2 compound that is soluble in the amine.

(f) **Why is the amine type CCU system the best?**

*(i) The amine type CCU system is not necessarily the best solution for all applications. It is the **MOST** mature and flexible system, able to capture CO_2 emissions (post-combustion) from the majority of industrial CO_2 emitters. In the next 5 years there will likely be a better solution available that may or may not involve the use of amines.*

(g) **Are there different types of amine carbon capture systems?**

(i) Yes, there are large scale custom system, and modularized, generic OEM solutions available for both small and medium scale. These solutions can range from "big stack" solutions that require absorption and desorption towers to "compact" solutions that fit in one (1) or two (2) 40ft sea container(s).

(h) **How does the system really work and what does the amine actually do?**

(i) The amine solvent contacts the flue gas (liquid-gas contact) either via a distribution tray or a packed bed. The amine solvent then chemically reacts with the CO_2 in the flue gas to form a soluble salt. The soluble salt contains the CO_2 and "tends towards" the amine solvent stream. The CO_2 is released from the solvent stream in a separate process unit using thermal energy; the CO_2 released is of high purity, as the solvent selectively binds to CO_2 (as well as H2O, NOX, SOX) opposed to N2.

(i) **Is any of the amine safe?**

(i) Special care must be taken when working with an amine solvent. It is toxic to humans and wildlife and should not be emitted into the environment in any quantity. Handling of the amine should be left to trained professionals, preferably those supplied by the OEM for O&M purposes.

(j) **Is any of the amine lost and therefore there is continuous amine makeup?**

(i) This is OEM, and solvent, specific. Oxygen readily reacts with the amine, decreasing performance of the CCU system. If the flue gas stream is kept relatively clean (i.e., low NOX, SOX, and PM) then solvent make-up will not be required as often. Some systems will require that at least some of the solvent be replaced every month. Trace amounts of solvent can also leave via the regenerated CO_2 stream – over time this will require make-up solvent be added.

(k) **If so, how much makeup amine is used by the system on an hourly or daily basis?**

(i) Again, this is system dependent, and the timescale is closer to monthly, or even quarterly, depending on quality of operation or selection of solvent.

(l) **What is the capture efficiency of a typical CCU system? In other words, how much of the CO_2 going into the system is actually captured, and what is not captured?**

(i) This ranges from 80-90% for optimized solutions (i.e., medium to high CO_2 concentrations with limited contaminants) to 50-60% for flexible systems that can take different quality CO_2 streams. The capture efficiency is somewhat based on the technology, but in the case of conventional amine systems, is heavily dependent on solvent choice and quality operation.

(m) **Does the system have other parasitic requirements, such as auxiliary steam and auxiliary power? If so, how much auxiliary steam and power is required to make this system operate properly?**

(i) Approximately 30-50 kWh of electricity is required per tonne of CO_2 captured in order to operate pumps and fans. Anywhere from 3-8 mmBtu of thermal energy is required to run the reboiler on a conventional amine system.

(n) **Are there any other emissions from the system, such as air, noise, water discharges, or odours?**

(i) CCU systems are largely integrated process units. The only things constantly entering and leaving the system are flue gas and concentrated CO_2.

(o) **Is the CO_2 captured food-grade? If not, what is required to make the CO_2 food-grade?**

(i) The captured CO_2 will be saturated with water. To store the CO_2 on-site, liquefaction will be required; in this liquefaction step the water is removed from the CO_2 to produce a 99.9-99.99% pure CO_2 stream. In some jurisdictions this quality of CO_2 is considered food-grade. Further PSA or TSA may be required to reach higher purities.

(p) **What up-time can we expect? Is it 90%? 95%? 98%?**

(i) Existing pilot systems have improved up-time into the 90%'s. It is expected that this is the minimum up-time guaranteed by an OEM, but will be dependent on the OEM.

(q) **What must be done to the captured CO_2 to actually store it on site?**

(i) In most cases, the CO_2 will be stored on-site in a dewer, as a liquid. This means that the CO_2 must be liquified, which is typically done by cooling to low temperatures via compression.

(r) **Do you think that we can really operate and maintain this type of technology? If not, what type of personnel are required to operate and maintain the typical CCU system?**

(i) It is likely that these CCU systems will be offered as-a-service, where you may maintain some ownership of the asset, but largely O&M will be undertaken by a third-party team (either from the OEM or others).

(s) **How much space is required for the different types of CCU systems?**

(i) Conventional amine systems require a larger area for equipment. Compact amine systems are designed to fit on smaller industrial sites and take up roughly 10 times less space (anywhere from 2-5 m2/tonne CO_2 captured). Other technologies (such as membrane separation) are designed to compete with amine systems in terms of space required.

(t) **Should the system be installed in a building?**

(i) It can be installed in a building. Depending on year-round temperatures of the site location, it may be preferably to operate this system in a climate-controlled environment (especially for winter environments).

(u) **What Carbon Capture system is best for my emissions profile?**

(i) *This is highly dependent on whether you have use for CO2 on-site (and thus require a high purity CO2 stream), if your process operates 24/7 for 300+ days a year, and if your organization is willing to take risks on technologies that are not yet commercially available.*

(ii) *Right now, most Carbon Capture systems being installed are amine solvent based systems simply because the technology is demonstrated and commercially available (i.e., economically palatable). This could change in the coming years.*

(v) **Is a manifold of exhaust ducting possible from several units to one capture processing system?**

(i) *Most systems to date have been testing or deployed using a single flue gas source to capture CO_2. Notwithstanding ducting best practices (i.e., back flow prevention, etc.), and accounting for pressure and temperature differentials, it is technically feasible to duct multiple flue gas sources to one Carbon Capture system.*

(w) **How are operating costs determined?**

(i) *Operating cost are a function of the price of electricity and the cost to produce thermal energy (steam or other) on-site. Electricity and (if using a natural gas boiler) natural gas consumption account for the majority of Carbon Capture operating costs.*

(x) **Should I expect significant downtime for maintenance?**

(i) *For most Carbon Capture systems, maintenance can be completed at defined intervals that align with plant or facility wide downtime for maintenance. Expect a conventional Carbon Capture system to be operating for ~8,000 hours a year.*

Appendix A
Jurisdictional Scans: Legislation and Financial Incentives

Jurisdictional Scan – Legislation to Force CO_2 Reduction

Federal Legislation in the United States

Clean Air Act

(a) The Clean Air Act (CAA) is a federal law that regulates air emissions from stationary and mobile sources.

(b) Among the many things this law entails, it allows the Environmental Protection Agency (EPA) to establish National Ambient Air Quality Standards (NAAQS) to protect public health, public welfare, and regulate the emissions of harmful air pollutants.

(c) Within the Clean Air Act, "Major Sources" are defined as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants.

(d) For any major source, the CAA requires that EPA sets forth emissions standards that require the maximum degree of reduction in emissions of hazardous air pollutants.

(e) These standards are most referred to as "Maximum Achievable Control Technology" or MACT.

(f) Recent developments and decisions made by the Supreme Court have limited the EPA's ability to regulate carbon dioxide emissions from the power generation sector. This ability was previously interpreted from Section 111 of the CAA.

Federal Legislation in Canada

Coal Fired Electricity Generation Regulations

(a) These regulations apply a performance standard to new coal-fired electricity generation units, and units that have reached the end of their useful life.

(b) The regulations define a new coal unit as a unit that started producing electricity on or after July 1, 2015. At the same time the regulations define an end-of-life coal unit as a unit that has at least 50 years of age.

(c) These regulations exclusively cover emissions of CO_2 only. That is because CO_2 represents 98% of the Greenhouse Gas (GHG) emissions from coal-fired units.

(d) The performance standard that makes up these regulations applied to both new and end of life coal units.

(e) The standard is set at the emissions level of Natural Gas Combined Cycle (NGCC) technology – a high efficiency type of natural gas generation (fixed at 420 t/GWh).

(f) Coal fired units that incorporate CCS can apply to receive a temporary exemption from the performance standard until December 31, 2024. However, units will have to provide documented evidence that they are meeting yearly regulated construction milestones.

Natural Gas Fired Electricity Generation Regulations

(a) These regulations establish a method of limiting the CO_2 emissions emitted via the generation of electricity by means of thermal energy that is released from the combustion of natural gas.

(b) More specifically these regulations can be applied to any boiler unit that has capacity of 25MW or more and that began generating electricity on or after January 1, 2019. Beginning on the first of the calendar year it must meet the below conditions:

   (i) More than 30% of its heat input, on average, during the calendar year comes from the combustion of natural gas

   (ii) The heat to electricity ratio is no more than 0.9

   (iii) The quantity of electricity that is generated is sold or distributed to the electric grid

(c) The regulations also apply to any combustion engine with a capacity of 25 MW or more, that began generating electricity on or after January 1, 2021. Beginning on January 1 of the calendar year the below conditions must be met:

   (i) More than 30% of its heat input, on average, during the calendar year comes from the combustion of natural gas

   (ii) 33% or more of its potential electrical output is sold or distributed to the electric grid

(d) The regulations can also be applied to either a boiler or combustion engine that began operation before January 1, 2019 (in the case of the boiler) or before January 1, 2021 (in the case of the combustion engine) if they meet the conditions below:

(i) Was moved to another facility on or after whichever of those dates is applicable; or

(ii) Is a combustion engine for which more than 50% of the total capacity of the combustion engines comes from the combustion engines installed on or after January 1, 2021, unless they are the engines that have a capacity of 150 MW or less and are installed to replace engines that have a capacity of 150 MW or less and that are installed before January 1, 2021.

(e) An owner for an applicable unit must not emit from the unit an amount of CO_2 from the combustion of fossil fuels, during the calendar year (on average) that is greater than any of the following intensity limits as applicable;

(i) 420 tonnes of CO_2 emissions/GWh of energy produced

- In the case of boiler units, and
- In the case of combustion engines that are equipped with at least one (1) combustion engine that has a capacity of more than 150 MW; and

(ii) 550 tonnes of CO_2 emissions/ GWh of energy produced in the case of combustion engine units that are equipped with combustion engines that have a capacity of 150 MW or less

Output Based Pricing System Regulations

(a) Within the Greenhouse Gas Pollution Pricing Act, the federal carbon pollution pricing system has two (2) parts:

(i) A regulatory charge on fuel (federal fuel charge)

(ii) A regulatory trading system for industry – the federal Output Based Pricing System (OPBS)

(b) OPBS is designed to ensure there is a price incentive for industrial emitters to reduce their greenhouse gas emissions. It is also in place to inspire innovation while maintaining competitiveness and protecting against “carbon leakage”.

(c) Carbon leakage being the risk of industrial facilities moving from one (1) region to another to avoid carbon tax.

(d) The OBPS applies in provinces that do not have an equivalent Carbon Pricing System in place.

(e) The Carbon Tax applied via the OBPS is set to rise from 50 CAD/tonne CO_2 in 2022 to 170 CAD/tonne CO_2 in 2030.

Clean Fuel Regulations

(a) The Clean Fuel Regulations require liquid fossil fuel primary suppliers to gradually decrease the carbon intensity of the gasoline and diesel that they produce and sell in Canada.

(b) The objective of these regulations is to reduce the CO_2 emissions produced by these fuels.

(c) The exact target with these regulations is to decrease the carbon intensity of gasoline and diesel by at least 15% by the year 2030.

(d) With this target the Clean Fuel Regulations will help to deliver up to 26 million tonnes (Mt) of GHG emissions reductions by 2030.

(e) This set of regulations is replacing the old Renewable Fuel Regulations.

(f) The new regulations take on a life-cycle approach, meaning they account for emissions associated with all stages of fuel production and use (extraction, processing, distribution, and end use).

(g) To account for all of these stages, a proper definition of carbon intensity is needed. The carbon intensity is defined as the measure of GHG emissions from the extraction, refining, distribution, and use of the fuel.

(h) Beginning in 2023, the reduction requirement for carbon intensity will be 3.5 grams of CO_2/MJ.

(i) Each year the reduction requirement will increase by 1.5 grams of CO_2/MJ with the requirement reaching 14 grams of CO_2/MJ in 2030 (that is carbon intensity of liquid fuels must drop by 14 grams of CO_2/MJ).

Proposed Clean Electricity Regulations

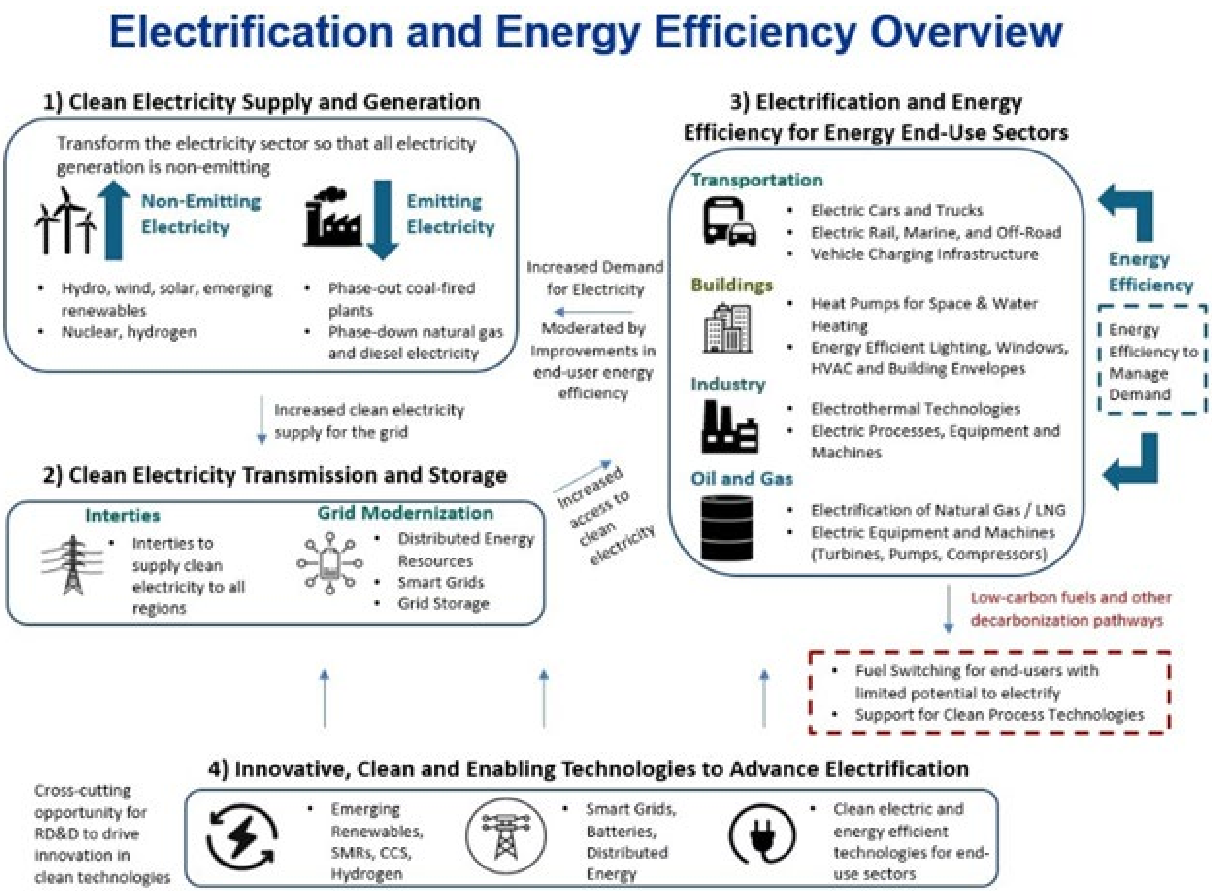
(a) The electrification of infrastructure and industry in Canada is viewed as essential for Canada to transition to net-zero emissions by the year 2050.

(b) Currently the Government of Canada is developing the Clean Electricity Regulations (CER) to push Canada to a net-zero electricity grid by the year 2035 to facilitate broader decarbonization via electrification.

(c) These regulations are centered around three (3) core principles:

- (i) Maximize GHG reductions to achieve net-zero emissions from the electricity grid by 2035.
- (ii) Ensure grid reliability to support a strong economy and ensure that Canadians have enough energy to support their heating and cooling needs in the winter and summer respectively.
- (iii) Maintain electricity affordability for homeowners and businesses.

(d) The figure below outlines the high-level concepts driving the development of the CER.



(e) While the CER is under development, and subject to changes prior to publishing, the draft mechanism to incent decarbonization of the electricity sector is as follows (**both** measures below apply):

(i) A performance standard for all fossil-fuel driven electricity generating units, which export power to the grid, or somewhere between 50-100 tonnes CO_2/GW.h.

- Any emissions above this limit would amount to a violation of the CER and a unit is prohibited from operating above that limit.

(ii) A financial compliance mechanism, which would require electricity generators to pay for all emissions associated with electricity generation, either via carbon credits/offsets or via the carbon tax.

State Level Legislation in the United States

(a) As seen in the tables on the following pages, the majority of decarbonization legislation, at the state level at least, is focused on electrical utilities reducing their CO_2 emissions associated with electricity production.

STATE	LINK TO LEGISLATION	DESCRIPTION
California	SB 100 and Executive Order B-55-18	SB 100, released in 2018, extended and expanded the existing state RPS. State agencies were required to submit implementation plans by the start of 2021. Along with this, in 2018, Governor Jerry Browns Executive Order B-55-18 set a statewide goal of carbon neutrality by no later than 2045.
Colorado	SB 19-236	A 2019 law (SB 19-236) codified a pledge previously made by Xcel, whose service territory covers about 60% of the state's load. The pledge made by Xcel Energy was to achieve 100% carbon free electricity by the year 2050.
Connecticut	Senate Bill 10	In 2019, Governor Ned Lamont's Executive Order (Number 3) set 2040 as the goal for carbon-free electricity. It also prompted the Department of Energy and Environmental Protection to develop a decarbonization plan for the power sector. By May 2022, Senate Bill 10, An Act Concerning Climate Change Mitigation, turned this goal into a law.
District of Columbia	DC Act 22-583	The Clean Energy DC Omnibus Amendment Act of 2018 amended the existing RPS to mandate 100% renewable electricity by 2032.
Hawaii	HB623	This 2015 legislation made Hawaii the first state to set a 100% RPS for the electricity sector.
Illinois	SB 2408	Legislation released in 2021, SB 2408, established a goal of 100% clean energy by the year 2050. Included in this goal are interim targets of 40% clean energy by 2030 and 50% clean energy by 2040.
Louisiana	JBE 2020-18	Governor John Bel Edwards 2020, executive order (JBE 2020-18) established a Climate Initiatives Task Force to put together a road map and make recommendations for a CO_2 reductions strategy. The strategy must include a target of net zero greenhouse gas emissions by 2050.
Maine	LD 1494 and LD1679	This legislation established in 2019 increased Maine's RPS to 80% by 2030 and set a goal of 100% by 2050. On top of that, LD1679 sets an economy wide goal of cutting greenhouse gases by 80% by 2050.
Maryland	Climate Solutions Now Act of 2022	Enacted by the General Assembly, this act includes a 2045 net zero goal.
Massachusetts	Bill S.9	In 2020, the Secretary of Energy and Environmental Affairs set a 2050 net-zero GHG emissions target on the basis of 2008 legislation. This same goal was then included in a March 2021 climate action law (Bill S.9). At the end of 2020 a decarbonization map was also released.
Michigan	Executive Directive 2020-10	Governor Gretchen Whitmer's order in 2020 (Executive Directive 2020-10) set a goal "to achieve economy-wide carbon neutrality no later than 2050." This directive prompted the Department of Environment, Great Lakes, and Energy to develop a plan by the end of the year 2021.

Nebraska	-	Nebraska is unique in that it is the only state served solely by publicly owned utilities. As of December 2021, the three (3) public utilities that serve the majority of customers all adopted 100% clean energy goals.
Nevada	SB 358	This 2019 legislation raised the RPS to 50% by 2030 while also setting a net-zero emission power sector goal by 2050.
New Jersey	Executive Order 28	Enacted by Governor Phil Murphy in 2018, this order set a carbon free goal for the power sector, while also directing the BPU to develop a master plan which was later released in 2020.
New Mexico	SB 489	2019 legislation, SB 489, requires utilities to have a zero-carbon power supply by the year 2045. This includes at least 80% renewables, with the exception of rural electric coops which have a 2050 target date.
New York	S6599	This 2019 legislation requires zero-emissions electricity by 2040 and sets the goal of cutting all state GHG's by 85% by the year 2050.
North Carolina	HB 951	HB 951, enacted in 2021 requires the North Carolina Utilities commission to take reasonable steps to achieve 70% reduction in CO_2 emissions from electrical generating facilities in the state by 2030, as well as carbon neutrality by 2050.
Oregon	HB 2021	Enacted in 2021, this legislation requires investor-owned utilities to reduce GHG emission associated with the electricity they sell 80% below baseline emissions by 2030, 90% below baseline by 2035 and 100% below baseline by 2040.
Rhode Island	H7277 SUB A and 20-01	Governor Gina Raimondo's 2020 Executive Order (20-01) requires the Office of Energy Resources to "conduct economic strategy, energy market analysis and develop viable policy and programmatic pathways" to help meet 100% of statewide electricity deliveries via renewables by 2030. H7277 SUB A, 2022 legislation provides updates to the states RPS to require 100% of RI's electricity to be offset by renewable production by the 2033.
Virginia	House Bill 1526 and Senate Bill 851	House Bill 1526 and Senate Bill 851, otherwise known as the 2020 Virginia Clean Economy Act, requires zero-carbon utilities by 2050 at the very latest. More specifically, the act requires 100% carbon free electricity by 2045 for Dominion Energy and 2050 for Appalachian Power Company.
Washington	SB5116	2019's Clean Energy Transformation Act was made applicable to all utilities. The states Commerce Department started a rule making process in August of 2019 and set a deadline for utilities to file an implementation plan by January 2022.
Wisconsin	EO38	In 2019 Governor Tony Evers Executive Order (EO38) directed a new office of Sustainability and Clean Energy to "achieve a goal" of 100% carbon-free power by the year 2050.

Provincial Legislation in Canada

Alberta

(a) The Technology Innovation and Emissions Reduction Fund (TIER) is applicable to facilities in Alberta that emitted 100,000 tonnes or more of GHG emissions annually in 2016 or any subsequent year.

(b) TIER imposes an output-based emissions standard on these facilities, which is specific to the facility itself or the industry it operates in.

(c) TIER regulated facilities have four (4) options for complying with the TIER requirements:

- (i) Improve facility operating efficiency
- (ii) Submit emission performance credits
- (iii) Submit emissions offsets
- (iv) Pay for fund credits

(d) Among the several other regulations setup by the provincial government of Alberta are:

- (i) Oil Sands Emissions Limit Act – Set an annual limit of 100 Mt GHG emissions on the oil sands. The act includes provisions for cogeneration and new upgrading capacity.
- (ii) Phasing out of coal-fired electricity by the year 2030.
- (iii) Renewable Fuels Standard – Requires a minimum annual average of 5% renewable ethanol in gasoline and 2%, bio-based diesel in diesel fuel. The renewable fuel must demonstrate at least 25% fewer GHG emissions that their petroleum counterpart.

British Columbia

(a) Greenhouse Gas Industrial Reporting and Control Act provides specific performance standards for industrial facilities or sectors.

(b) Currently the Act requires Liquefied Natural Gas (LNG) facilities to report their GHG emissions and adhere to benchmarks.

(c) The emissions limit for LNG facilities under this act is 0.16 tonnes of GHG emissions for each tonne of LNG produced.

(d) Along with the above act, a number of regulations came into effect in January 2016, including the following:

- (i) Greenhouse Gas Emission Reporting Regulation – Requires industrial operations emitting 10000 tonnes of CO_2 per year to report their GHG emissions to the province annually.
- (ii) Greenhouse Gas Emission Control Regulation – Establishes the B.C Carbon Registry to monitor compliance unit transactions and enable the issuance, transfer, and retirement of compliance units.

(iii) Greenhouse Gas Emission Administrative Penalties and Appeals Regulation – Prescribes administrative penalties for non-compliance with the Act or any of its subsequent regulations.

(e) Besides the above Act there are several other regulations in place to regulate CO_2 emissions:

(i) Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act – Focuses on reducing GHG emissions while also creating new opportunities for the bioenergy sector.

(ii) Renewable and Low Carbon Fuel Requirements Regulation – Fuel suppliers must have a minimum fuel content by volume and meet targets for reducing fuel carbon intensity.

(iii) Climate Change Accountability Act – Sets annual targets to reduce GHG emissions levels by a certain fraction of what they were in the year 2007. This includes targets to reduce levels by 33 to 38% by the year 2030 in the oil and gas sector and reduce levels by 38 to 43 % by the year 2030 in the industrial sector.

(iv) Clean Energy Act – Targets making the province self-sufficient in electricity generation beginning in 2016 and continuing each year after that. The end goal is to have 93% of energy produced be clean and renewable.

Ontario

(a) Ontario released its Preserving and Protecting our Environment for Future Generations: A "Made In Ontario Environment Plan" back in November of 2018.

(b) Under the guidance of this plan, Ontario has committed to reducing CO_2 emissions levels by 30% below 2005 levels by the year 2030.

(c) Within this plan are the following actions:

(i) Emissions Performance Standard (EPS)

(ii) Ontario Carbon Trust

(iii) Ontario Reverse Auction

(iv) Green Gasoline

(d) In September of 2020 Canada's Federal Government accepted Ontario's EPS program as an alternative to the federal OBPS.

(e) This transition, now finalized, means that the EPS:

(i) Applies to sectors covered by the OBPS based on emissions threshold of 50,000 tonnes of CO_2 per year

(ii) Requires regulated entities to reduce emissions or purchase/use compliance units to cover off the difference between that entity's total emissions and the annual limit

(iii) Sets the price of compliance units in accordance with the federal carbon price

(f) Changes to the EPS in the 2023 calendar year are expected to expand the acceptable use of Carbon Capture and Storage for emission reductions.

(g) Carbon Capture and Utilization has not yet been recognized as an acceptable form of CO_2 reduction under the EPS.

Manitoba

(a) After the province of Manitoba decided against implementing their own carbon pricing scheme, the federal carbon pricing system under the Federal Greenhouse Gas Pollution Pricing Act now applies in the province (and has since 2019).

(b) The Greenhouse Gas Pollution Pricing Act (GGPPA) is made up of two (2) main parts:

(i) The first part applies a charge to 21 types of fuel delivered, transferred, used, produced, imported, or brought into the province. A charge is also applied to combustible waste that is burned for the purposes of producing energy.

(ii) The second part introduces an output-based pricing system (OBPS) for industrial emitters that have reported 50,000 tonnes of CO_2 equivalent or more in 2014 or a subsequent year. Under the OBPS, facilities will pay a carbon price if their emissions levels exceed the set level. On the contrast, facilities that emit below the set level will earn credits.

(c) Although the province does not have its own pricing scheme for carbon in 2018, Manitoba became the first Canadian jurisdiction to implement climate accountability legislation through the Climate and Green Plan Implementation Act (CGPIA).

(d) With the CGPIA, a Carbon Savings Account (CSA) is introduced which establishes five-year cumulative emissions reductions goals for the province.

New Brunswick

(a) In December 2017, the provincial government of New Brunswick issued an update to their Transitioning to a Low-Carbon Economy – New Brunswick's Climate Action Plan. The plan works to:

(i) Reduce total GHG emission outputs to 14.8 Mt by 2020, 10.7 Mt by 2030 and 5 Mt by 2050

(ii) Phase out coal-fired electricity generation by 2030

(iii) Make the government carbon neutral by 2030

(iv) Replace fuel oils with low-carbon fuels such as wood pellets, natural gas, biomass and solar energy

(v) Extend reporting requirements to facilities that emit at least 10,000 tonnes of GHG emissions per year and management requirements to facilities that emit at least 25,000 tonnes of GHG emissions per year

(vi) Apply output-based performance standards to large industries that emit over 50,000 tonnes of GHGs annually

(b) New Brunswick has also implemented a tax on gasoline, motive fuel, and carbon emitting products purchased or consumed in the province under the Gasoline and Motive Fuel Tax Act (GMFTA).

(c) Currently, the GMFTA applies to 20 types of fuels and is levied at 50 CAD/tonne.

Newfoundland and Labrador

(a) In 2019, the provincial government of Newfoundland released their new action plan, The Way Forward on Climate Change in Newfoundland and Labrador.

(b) Under this plan, the province is aiming to reduce their GHG emissions by 30% below its 2005 level by 2030.

(c) Along with the above act, the Management of Greenhouse Gas Act received approval in June of 2016.

(d) This act targets large emitters within the province (particularly industrial emitters) with new emission reporting requirements and a performance standard system.

(e) The reporting requirements for said act are listed in the Management of Greenhouse Gas Reporting Regulations:

(i) Facilities that emit 15,000 tonnes of CO_2 equivalent or more of GHG in a year must report their emissions to the provincial government, according to the regulations defined above.

(ii) Facilities that emit between 15,000 and 25,000 tonnes of CO_2 of GHG annually may apply as designated opted-in facilities

(iii) Facilities that emit more than 25,000 tonnes of CO_2 equivalent are subject to annual GHG reduction targets.

(f) Lastly, another piece of legislation the province has put in place is its Made in Newfoundland and Labrador carbon pricing program.

(g) The first key component of the program is the carbon tax applied to combusted fossil fuels across the economy under the Revenue Administration Act.

(h) The second key component of this act is the requirement for large industrial facilities and large-scale electricity generation to reduce their GHG emissions by 10% in 2021 and 12% in 2022.

Nova Scotia

(a) In January 2019, Nova Scotia's Cap and Trade program came into effect.

(b) The program sets annual limits on the total amount of GHG emissions allowed in the province for the years 2019-2022.

(c) Every year the province creates emission allowances that can be put in circulation equal to those years cap.

(d) The thresholds listed below make participation in the program mandatory:

   (i) Facilities generating 50,000 tonnes or more of GHG emissions annually

   (ii) Petroleum product supplier that places 200 liters or more of fuel per year on the Nova Scotia market for consumption within the province.

   (iii) Natural gas distributors that deliver natural gas for consumption in Nova Scotia, and when combusted they produce 10,000 tonnes or more of GHG emissions, annually.

   (iv) Electricity importers that import electricity into the province for consumption and whose GHG emissions from the generation of the electricity imported is greater than 10,000 tonnes, annually.

(e) There are several other regulations the province of Nova Scotia has put in place to limit CO_2 emissions, some of which are listed below:

   (i) Sustainable Development Goals Act – Sets new target to fight climate change and mandates the creation of a strategic plan called the Climate Change Plan for Growth

   (ii) Renewable Electricity Regulations – Each year beginning with the calendar year 2020, all load serving entities will have to supply its customers with the renewable electricity in an amount equal to or greater than 40% of the total amount of electricity supplied to its customers

Saskatchewan

(a) Released in December of 2017, the Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy, was implemented to address GHG emissions without having to introduce a carbon tax.

(b) The program includes a framework to measure and improve the provinces resilience, output-based performance standards to regulate industrial emissions intensity reduction and oil and gas emissions management regulations.

(c) It is the intent of this program to reduce GHG emissions by 12 million tonnes by the year 2030.

(d) Despite all of this, Saskatchewan's central legislation for the reduction of GHG emissions is the Management and Reduction of Greenhouse Gases Act.

(e) Within this act the following regulations have been enacted:

(i) Reporting and General Regulations – Impose reporting requirements for provincial facilities with GHG emissions greater than 10,000 tonnes of CO_2 equivalent per year

(ii) Standards and Compliance Regulations – Set performance standards for emissions on a per unit of production basis, prescribe emissions limits and create options for regulated entities to meet their compliance obligations if their emissions do end up exceeding the limit.

(iii) General and Electricity Producer Regulations – General provisions pertaining to GHG calculations and reporting, administrative penalties, and certain matters respecting natural gas and coal-fired generators.

Quebec

(a) 2013 saw Quebec set up a cap-and-trade system for greenhouse gas emission allowances.

(b) Through the Western Climate Initiative Quebec's market has been integrated with California. This joint market is the only one of its kind, in that it is the world's only carbon market designed, developed, and operated exclusively by subnational governments in different countries.

(c) This market, that Quebec shares with California, allows for joint auctions of emissions allowances as well as the harmonization of regulations and reporting.

(d) The carbon market is intended for the emitters listed below:

(i) Industrial establishments that emit 25,000 metric tons or more of CO_2 equivalent annually

(ii) Electricity producers and importers that emit 25,000 metric tons or more of CO_2 equivalent annually

(iii) Fossil Fuel distributors in Quebec (gasoline, diesel fuel, propane, natural gas, and heating oil)

(e) In conjunction with the cap-and-trade system, in October 2020, Bill 44 was passed by the National Assembly of Quebec which states that all funding generated by the cap-and-trade program must be geared towards climate change measures.

(f) Another policy put in place by the Government of Quebec in April of 2016 is the 2030 Energy Policy.

(g) The policy has five (5) main targets that it looks at achieving:

(i) Enhance energy efficiency by 15%

(ii) Reduce the amount of petroleum products used by 40%

(iii) Eliminate the use of thermal coal

(iv) Increase overall renewable energy output by 25%

(v) Increase bioenergy production by 50%

Jurisdictional Scan – Financial Incentives for CO_2 Reduction

Federal Funding in the United States

45Q

(a) This federal fund is a performance-based tax credit for carbon capture projects detailed in section 45Q of the US tax code.

(b) The fund can be claimed when an eligible project has done the following:

(i) Securely stored the captured CO_2 in a geologic formation, such as an oil field or saline formation etc.

(ii) Used captured CO_2 or its precursor carbon monoxide as a feedstock to produce fuels, chemicals, and products such as concrete in a way that results in emissions reductions as defined by federal requirements

(c) To be eligible to claim this tax credit, one must be the owner of the capture equipment. That party must physically or contractually ensure the storage or utilization of the CO_2 or CO and may even elect to transfer the credit to another party that stores or puts the CO_2 or CO to good use.

(d) Annual carbon capture thresholds, as listed below determine the eligibility of different types of facilities for the credits:

25,000-500,000 metric tonnes of CO_2/CO: Beneficial use projects other than Enhanced Oil Recovery (EOR) projects

(i) Minimum 100,000 metric tonnes of CO_2/CO: All other industrial facilities (other than electric generating units), including direct air capture

(ii) Minimum 500,000 metric tonnes of CO_2/CO: Electric generating units

(e) The tax credit amount that a party is eligible for depends on the project type:

(i) $35/tonne for CO_2 stored geologically through EOR

(ii) $35/tonne for other beneficial use of CO_2 or CO such as converting carbon emissions into fuels, chemicals, or useful products like cement

(iii) $50/tonne for CO_2 stored in other geologic formations and not used in EOR

Inflation Reduction Act Expansion of 45Q

(a) The expansion of 45Q reduces the risk to private capital of investing in the deployment of carbon capture technology across a range of industries, which include electric power generation, ethanol, and fertilizer production, natural gas processing, refining, chemicals production, and the manufacturing of steel and cement.

(b) The changes made to 45Q will help to attract investment in projects:

CHANGE	IMPORTANCE OF CARBON CAPTURE PROJECTS
Increases credit values.	Helps to address the cost gap between carbon capture and transport costs, and the amount companies will pay for captured carbon.
Expanded credit eligibility to include other uses of captured carbon (in addition to EOR), projects that capture carbon oxide and direct air capture projects.	Expands the eligibility to a wider scope of industries that can use captured carbon emissions.
Greater financial certainty by lifting the credit cap and providing clear timing for eligibility.	Helps to provide certainty that the credit will be available once the timeline and requirements are met to store and/or use the captured carbon. This improvement is expected to catalyze a significant increase in investment to carbon capture projects.
Expands eligibility to a number of new industries by lowering the carbon capture threshold and expanding definitions for qualified facilities and qualified carbon.	Helps to support investment in other industries where innovation is required to reduce costs and achieve increased deployment. A number of industries have significant potential to utilize carbon capture but were excluded from claiming the original 45Q as a result of eligibility requirements.
Allows the owner of the capture equipment to transfer the credit to another party that stores or puts the CO_2/CO to good use.	Enables different business models by providing greater flexibility to determine which entity can use the tax credit. Allows companies that traditional cannot take advantage of tax credits to participate. Companies without tax liability or insufficient tax liability to fully monetize the credit will now be able to use 45Q to help finance carbon capture projects.

Federal Funding in Canada

Low Carbon Economy Fund

(a) Low Carbon Economy Fund (LCEF) helps to support projects that reduce Canada's greenhouse gas emissions, generate clean growth, build resilient communities, all while creating jobs for Canadians.

(b) In Canada's 2030 Emissions Reduction Plan, the government of Canada committed to expanding the LCEF with a $2.2 billion recapitalization over 7 years, beginning in 2022-23.

(c) The LCEF currently has two (2) envelopes, namely:

(i) The Low Carbon Economy Leadership Fund

(ii) The Low Carbon Economy Challenge

(d) Provinces and territories will play a crucial role in implementing the Pan-Canadian Framework on Clean Growth and Climate Change. As such, the Low Carbon Economy Leadership Fund will provide $1.4 billion to provinces and territories that do well to adopt the above Framework.

(e) Provinces and territories are eligible to receive up to $30 million in funding (plus additional funding based on population).

(f) The Low Carbon Economy Challenge will provide $500 million to a variety of recipients. These recipients include provinces, territories, businesses, municipalities, not-for-profits, and Indigenous communities and organizations.

(g) Successful recipients of this challenge will be able to leverage ingenuity nationwide to help reduce emissions and generate clean growth in support of the Framework and Canada's climate plan.

OBPS Decarbonization Incentive Program

(a) The Decarbonization Incentive Program (DIP) is a merit-based program that is funded by the returns from the Output-Based Pricing System (OBPS).

(b) The objectives of DIP's are to incentivize long-term decarbonization of Canada's industrial sectors and support Canada's greenhouse gas (GHG) emissions reduction goals.

(c) The program will provide support for single or multi-year projects to accelerate the deployment of commercially available and/or proven low-carbon technologies within the following eligible provinces:

(i) Manitoba

(ii) Saskatchewan

(iii) Ontario

(iv) New Brunswick

(d) Applications for DIP will be held on a continuous basis until available funding for a respective province has been used up fully.

(e) In terms of available funding, applicants to DIP must request a minimum of $500,000 for each project while at the same time respecting cost-share limits.

(f) Regardless of available funding, projects may request no more than $10 million in total project funding from the DIP.

(g) To be eligible for the program, applicants must meet the following requirements:

(i) Be legal entities incorporated or registered in Canada

(ii) Operate or have a controlling ownership stake in an eligible facility covered under the federal OPBS, located in one of the eligible provinces

(iii) Demonstrate they have the authority over the facility or asset to undertake the project

(h) For a project to be considered for funding the project must occur at an eligible facility as outlined above and result in GHG emissions reductions. The GHG emissions reduction requirements are as follows:

(i) Material in the year 2030 and measurable over the lifetime of the project

(ii) Affecting sources of GHG emissions either within the facility's direct control and/or from acquired sources of energy such as electricity or purchased heat/steam

(iii) Incremental to GHG emissions reductions obtained by other required actions, such as regulatory requirements or business-as-usual maintenance and repairs

Energy Innovation Program

(a) Canada's Energy Innovation Program (EIP), administered by Natural Resources Canada (NRCan), focuses on advancing clean energy technologies that will help Canada to meet its climate control targets, while also supporting the transition to a low carbon economy.

(b) As a part of budget in 2021, the Canadian Government is investing $319 million over 7 years of research, development, and demonstrations to help advance the availability of CCUS technologies.

(c) The CCUS RD&D call will focus on early-stage RD&D activities across three (3) varying focus areas. Those focus areas being:

(i) Capture – To drive down the cost and enhance performance of various capture technologies. The deadline to apply for this focus area is October 3, 2022.

(ii) Storage/ Sequestration – To characterize and develop safe, permanent sub-surface CO_2 storage that will support planning of cost-efficient storage opportunities nationwide. Expression of interest for this program will open in the fall of 2022.

(iii) Utilization – To expand the strategic uses of CO_2 and support the development of cost and energy efficient utilization options. Expression of interest for this program will open in winter of 2023.

Investment Tax Credit

(a) In Canada's 2021 budget the government proposed an investment tax credit for capital invested in CCUS projects with the goal of reducing emissions by at least 15 megatons of CO_2 annually.

(b) The intent is that this new Investment Tax Credit (ITC) will be available for a wide range of CCUS applications across different industrial subsectors. Some of these sectors include blue hydrogen projects and direct air capture projects (this is to the extent that the CO_2 captured is not used in EOR projects).

(c) It is expected that the ITC will cover 50% of CAPEX for eligible CCUS projects initially, before tapering to 25% of CAPEX in later years.

(d) The Government of Canada has plans to make the ITC available sometime in 2022/2023.

State Level Funding in the United States

Texas

Type: Multiple Policies

Description:

(a) *Direct Financial Assistance*: In 2007, HB 3732 created a program to help finance advanced clean energy projects, for example, coal-fired power plants with carbon capture technology. It authorized the Texas State Energy Conservation Office to award grants and loans to these projects.

(b) *State Assumption of Long-Term Liability*: In 2009, HB 1796 authorized the development and regulation of an offshore deep subsurface geologic repository for storing CO_2. The Texas School Land Board would assume ownership and liability for any CO_2 injected in the repository after ensuring that permanent storage has been verified and the storage location met all applicable state and federal requirements for closure of CO_2 storage sites.

(c) *Tax Incentives*: In 2007, HB 3732 established a tax rate reduction for oil producers who use man-made CO_2 for carbon dioxide enhanced oil recovery (CO2-EOR). An applicant for the tax credit must obtain certification from the Texas Railroad Commission if the CO_2 is stored in an oil or natural gas reservoir or the Texas Commission on Environmental Quality, if the CO_2 is stored in a different geological formation. The agency must certify that at least 90 percent of the CO_2 will remain stored for 1,000 years. The same bill established a property tax reduction for advanced clean energy projects, for example, certain projects with carbon capture technology.

(d) In 2009, HB 469 established a clean energy franchise tax credit. Coal-fired power plants that capture and sequester at least 70 percent of CO_2 emissions and have been certified as clean energy projects by the Texas Railroad Commission may apply to the Texas comptroller for a franchise tax exemption equal to the lesser of $100 million or 10 percent of total capital costs. The bill also creates a sales and use tax exemption for the installation costs of carbon capture technology as long as the captured CO_2 is man-made and will be used for EOR or stored with the reasonable expectation that at least 99 percent of the CO_2 will remain sequestered from the atmosphere for at least 1,000 years.

New Mexico

Type: Utility Cost Recovery Mechanism

Description:

(a) In 2009, SB 994 directed the New Mexico Public Regulation Commission to adopt rules to allow public utilities a reasonable opportunity to recover costs related to clean energy projects. This included coal-fired power generation with carbon capture technology meeting certain emissions specifications.

Louisiana

Type: Multiple Policies

Description:

(a) *State Assumption of Long-Term Liability*: In 2009, House Bill 661 authorized the transfer of liability for stored CO_2 from storage operator to the state. Ten years after CO_2 injection has ended at a geologic storage project, the Louisiana commissioner of conservation will issue a certificate of completion of injection operations. This is provided that the CO_2 storage operator can demonstrate that the storage reservoir "is reasonably expected to retain mechanical integrity and the carbon dioxide will reasonably remain emplaced." Upon the issuance of the certificate, the storage operator will be released from liability related to the storage facility.

(b) *Tax Incentives*: In 2016, HB 61 and HB 62 revised tax exemptions for man-made CO_2 used in EOR. Specifically, the sale of man-made CO_2 for an EOR project approved by the assistant secretary of the Louisiana Department of Natural Resources Office of Conservation had been exempt from retail sales tax until April 2016. The bills raised the tax rate to 5 percent.

Mississippi

Type: Multiple Policies

Description:

(a) *Utility Cost Recovery Mechanism*: In 2013, HB 894 allowed the Mississippi Public Service Commission (PSC) to approve ratepayer recovery for the Kemper County Energy Facility (Kemper). The PSC sanctioned Mississippi Power to increase its rates to account for the costs of retrofitting Kemper with coal gasification and carbon capture technology, capping cost recovery at $2.4 billion.

(b) *Tax Incentives*: In 2009, HB 1459 approved tax incentives for CO_2 EOR using both naturally occurring and man-made CO_2. Specifically, the sales tax on the sale of CO_2 for EOR or geologic storage was reduced to 1.5 percent. Separately, a property tax exemption was established for up to 50 percent of the total value of the Kemper project.

(c) In 2013, HB 841 extended the 1.5 percent tax rate to the sale of electricity to an oil producer for CO2-EOR and geologic storage of CO_2. Additionally, pipelines and other equipment used to transport CO_2 for EOR are exempt from ad valorem property taxes (excluding taxes for school district purposes). Finally, severance tax on oil produced through CO_2-EOR has been reduced.

Kansas

Type: Multiple Policies

Description:

(a) *No State Assumption of Long Term Liability:* In 2010, HB 2418 clarified that except as permitted by the Kansas Tort Claims Act, Kansas has no liability related to leaks or discharge of CO_2 from any injection well or underground storage of the CO_2.

(b) *Tax Incentives:* HB 2419 established tax incentives for underground storage of CO_2 in 2007. These incentives include income tax reduction and property tax exemption. Specifically, after December 31, 2007, the taxpayer may deduct from adjusted gross income the amortized costs of machinery and equipment for CO_2 capture, sequestration or utilization for up to 10 years. The property tax exemptions lasts for 5 years all CO_2 capture, sequestration, or utilization property. This includes electrical generation units.

Wyoming

Type: Multiple Policies

Description:

(a) *Direct Financial Assistance:* The Wyoming Pipeline Authority is authorized to issue bonds and provide loans for pipeline infrastructure. This includes CO_2 transportation pipelines.

(b) *Tax Incentives:* Any sales of CO_2 for use in EOR is not subject to state sales tax.

Montana

Type: Multiple Policies

Description:

(a) *State Assumption of Long Term Liability:* In 2009, SB 498 approved the transfer of liability for injected CO_2 from geologically storage operators to the state. Fifteen years after CO_2 geologic storage ends, a CO_2 geologic storage operator may apply to the Montana Board of Oil and Gas Conservation for a certificate of project completion.

(b) Once the certificate has been issued, and a 15 year period of monitoring has finished, the CO_2 geologic storage operator may apply to transfer the title, associated liability and stored CO_2 in the storage reservoir to the state.

(c) *Tax Incentives:* In 2007, the Jobs and Energy Development Incentives Act (HB 3) setup tax incentives for which CO_2 from the coal gasification process is sequestered, and clean advanced coal research can take place using development and carbon sequestration equipment.

(d) For these facilities and equipment the associated property taxes may be reduced by up to 50% of their taxable value. In addition, in May 2015, Montana put forth HB 156, which provided property tax abatement for carbon capture and sequestration equipment.

Virginia

Type: Utility Cost Recovery Mechanism

Description:

(a) In 2007, SB 1416 authorized utilities to recover an increased rate of return on investments in specific projects. Some of which include coal-fired power plants with carbon capture technology.

Kentucky

Type: Multiple Policies

Description:

(a) *State Assumption of Long-Term Liability:* In 2011, House Bill 259 approved the transfer of ownership and liability of a CO_2 storage facility to the federal government (if a federal program exists) or to the Kentucky Finance and Administration Cabinet (following project completion, plugging, and a required period of post-closure monitoring).

(b) *Tax Incentives:* The Incentives for Energy Act (HB 1) established tax incentives for certain facilities that are carbon capture ready. This includes alternative fuel facilities or gasification facilities that use oil shale, tar sands, coal, or biomass resources.

(c) The Act also enacts tax incentives for CO_2 transmission pipelines. These tax incentives can include refunds of sales and use taxes on personal property, a reduction of up to 80% of the severance taxes on coal, tax credits applicable to income tax and wage assessment incentives.

(d) These tax incentives may apply to up to 50% of capital investment and are available for up to 25 years.

Illinois

Type: Multiple Policies

Description:

(a) *Direct Financial Assistance:* In 2007, the Illinois Power Agency Act (SB 1592) authorized utilities, electric cooperatives, and municipal utilities to assess a charge on customers. This charge was to be deposited in a Renewable Energy Resources Trust Fund and a Coal Technology Development Assistance Fund to support capturing emissions from coal-fired power plants and improving coal miner safety. The Act enabled the Illinois Finance Authority to issue bonds to help the Illinois Power Agency finance development and construction of coal-fired power plants with carbon capture technology.

(b) *Off-Take Agreements*: In 2009, the Clean Coal Portfolio Standard Law (P.A. 95-1027) directed utilities to enter into sourcing agreements with initial clean coal facilities in Illinois. This ended up representing at least 5 percent of each utility's total supply.

(c) *Utility Cost Recovery Mechanism*: In 2009, the Clean Coal Portfolio Standard Law (P.A. 95-1027) established that utilities would be entitled to full cost recovery for these costs related to carbon capture technology on coal-fired power plants.

(d) *Clean Energy Standard*: In 2009, the Clean Coal Portfolio Standard Law (P.A. 95-1027) established that by January 1, 2025, it is the goal of Illinois that 25 percent of the electricity used is generated by cost-effective clean coal facilities.

North Dakota

Type: Multiple Policies

Description:

(a) *Direct Financial Assistance*: The North Dakota Century Code enables the North Dakota Pipeline Authority to make grants, loans, or other forms of financial assistance to support the development of pipelines, including for transportation of carbon dioxide.

(b) *State Assumption of Long-Term Liability*: SB 2095, approved in 2009, authorized the transfer of liability for injected CO_2 from geologic storage operators to the state. Ten years after CO_2 injections end, the North Dakota Industrial Commission may issue a certificate of project completion to a storage project operator. This is provided that the operator has met all of legal and safety requirements for storing CO_2. Once the certification of project completion has been issued, title to and liability associated with the CO_2 storage facility and stored CO_2 transfers from the CO_2 storage facility operator to the state.

(c) *Tax Incentives:* North Dakota has enacted several tax incentives for carbon capture technology. In 2009, SB 2221 created a CO_2 capture tax credit for coal conversion facilities (this includes electrical generating plants and coal gasification facilities). This tax credit relates to the North Dakota facilities privilege tax, which is what the state imposes on coal conversion facilities instead of a property tax. To qualify for the 20 percent tax credit, coal conversion facilities must capture at least 20 percent of their CO_2 emissions produced. An additional 1 percent tax reduction is available for every additional 2 percent of captured emissions, up to a maximum of a 50 percent tax reduction for a facility that captures 80 percent of its emissions produced.

(d) In 2009, SB 2034 established an exemption from the oil extraction tax for oil produced by CO_2-EOR. In 2015, SB 2318 created a personal property tax exemption for equipment (e.g. pipelines that transport CO_2 for EOR). This exemption applies during construction and for up to 10 years after operation begins. Finally, S.B. 2318 also created sales and use tax exemptions for personal property used to construct or expand CO_2 capture systems for EOR. This includes the sale of the CO_2 for EOR.

Utah

Type: Clean Energy Standard

Description:

(a) SB 202 established a voluntary Renewable Portfolio goal to help generate 20% of "adjusted retail electric sales" from renewable or other reliable sources. Coal and fired power plants with carbon capture are eligible to indirectly help meet the goal at hand.

Colorado

Type: Utility Cost Recovery Mechanism

Description:

(a) HB 06-1281 passed in 2006, directed the Colorado Public Utilities Commission to review proposals from electric utilities to construct Integrated Gasification Combined Cycle (IGCC) power plants of 350 MW or less. This bill authorized utilities to seek recovery of costs incurred as a part the projects.

California

Type: Low Carbon Fuel Standard

Description:

(a) To help California meet the goals of SB 32 to lower GHG emissions by 40% of 1990 levels by the year 2030, the California Air Resources Board (CARB) proposed updates to the Low Carbon Fuel Standard (LCFS). The updates to this standard include a CCS Protocol that allows CCS projects to qualify for LCFS credits.

West Virginia

Type: Repealed

Description:

(a) In 2009, the Alternative and Renewable Energy Portfolio Act (HB 103) required electric utilities (excluding municipal utilities, rural electric cooperatives, and utilities serving fewer than 30,000 residential customers) to obtain 25 percent of their electricity from alternative or renewable energy sources by 2025. Alternative energy sources could include coal-fired power plants with carbon capture technology.

(b) In 2015, HB 2001 repealed the alternative and renewable energy portfolio standard.

Ohio

Type: Repealed

Description:

(a) In 2008, SB 221 established an alternative energy portfolio standard. This standard being a requirement for utilities to incrementally ramp up the percentage of their retail electricity supply from alternative energy resources such as renewable energy until it reached 25 percent in 2025. The law provided that half of this target could be met through the use of advanced energy resources, including coal-fired power plants with carbon capture technology.

(b) In 2014, SB 310 eliminated the eligibility of advanced energy resources such as coal-fired power plants with carbon capture technology, halted the renewable energy ramp up schedule for two years, and extended the target date for the new 12.5 percent goal to 2026. In 2017, the halt ended. The 12.5 percent goal by 2026 and revised ramp-up schedule remain.

Indiana

Type: Off-Take Agreement Only

Description:

(a) In 2010, Indiana's Finance Authority agreed on a 30-year contract to purchase Substitute Natural Gas (SNG) from the proposed Indiana Gasification project. This project being a SNG production plant that would capture 90% of its CO_2 emissions.

(b) Unfortunately, the proposed project was not carried out.

Michigan

Type: Clean Energy Standard

Description:

(a) The Clean, Renewable, and Efficiency Act (SB 213) passed in 2008 helped to establish an Integrated Renewable Portfolio Standard (RPS), which required energy providers to provide 10% of electricity through renewable energy generation, renewable energy credits and energy efficiency by the year 2015.

(b) A maximum of 1% of this may be met through the use of "advanced cleaner energy systems". This includes coal fired electric generating facilities that capture and sequester 85% of CO_2 emissions. In 2016, SB 438 pushed the goal to 15% by the year 2021.

Massachusetts

Type: Repealed

Description:

(a) In 2008, the Massachusetts Green Communities Act (SB 2768) created an alternative energy portfolio standard that requires the state to meet 5 percent of its electric load with alternative energy by 2020. The standard also includes subsequent annual increases of 0.25 %.

(b) Gasification units that establish and maintain a permanent capture and storage program were originally eligible, but that option was later eliminated in 2016 (HB 4568).

Provincial Level Funding in Canada

Alberta

(a) The provincial government of Alberta has committed to $1.24 billion of funding for two (2) commercial-scale CCUS projects through 2025.

(b) Both projects are projected to reduce CO_2 emissions by up to 2.76 million tonnes per year.

(c) This figure is equivalent to the yearly emissions of around 600,000 cars.

(d) The two (2) projects being funded are:

(i) Quest Carbon Capture and Storage

(ii) Alberta Carbon Trunk Line Project

British Columbia

(a) In 2021 the CleanBC Industry Fund invested $83.5 million into 32emission-reduction projects, with industry and partners making an additional contribution of nearly $104 million.

(b) The following are a few examples of projects that received funding:

(i) ARC Resources Ltd. – Dawson Creek

- Funding: $13.66 million
- Emissions reduced: 1 million tonnes of CO_2 through 2031

(ii) Canadian Natural Resources Ltd. – Northeast B.C.

- Funding: $2.07 million
- Emissions reduced: 298913 tonnes of CO_2 through 2031

Ontario

(a) For the most part, Ontario is relying on federal government funding when it comes to GHG emission reduction.

Manitoba

(a) Initially launched in 2020, Manitoba's Conservation and Climate Fund supports projects being implemented by non-profit organizations, educational institutions, municipalities, and northern communities to address climate change.

(b) This past year, Manitoba has recently awarded another $1.5 million in grants that will support 14 projects that are working to reduce GHG emissions.

(c) A few examples of projects that received funding are listed below:

(i) Little Brown Jug Brewing Company – Received $150,000 for a CO_2 capture project

(ii) Carbon Lock Technologies Inc. – Received $125,000 for a project that carbonizes biosolids to address methane emissions

New Brunswick

(a) Closing at the end of October 2022, New Brunswick's Climate Impact Research Fund aims at supporting research into technologies with the potential to mitigate GHG emissions.

(b) The fund is soliciting applications for grants of up to $90,000 for projects that are to be completed within two years.

(c) The project must include a non-academic collaborator and strong highly qualified personnel (HQP) training and development component.

(d) Included in the list of project areas eligible to receive funding is CCUS projects.

Newfoundland and Labrador

(a) The Climate Change Challenge Fund (CCCF) is an application-based grant program that is designed to enable businesses, industry, municipalities, Indigenous organizations, and public sector entities to undertake greenhouse gas reduction projects within the province.

(b) The fund will be implemented over five years (2019/20 – 2023/24) by the Department of Environment and Climate Change.

(c) The fund is supported by more than $38 million in funding from the Low Carbon Economy Leadership Fund (a joint federal and provincial initiative).

Nova Scotia

(a) The province of Nova Scotia is investing $37.3 million from the Green Fund into projects that support the Environmental Goals and Climate Change Reduction Act and help to reduce greenhouse gas emissions.

(b) Of the $37.3 million, $15 million is being spread out over three years for the Sustainable Communities Challenge Fund.

(c) This fund will be used to support communities to adapt to the impacts of climate change and reduce GHG emissions.

Saskatchewan

(a) The main incentive programs available within Saskatchewan for carbon capture projects are:

  (i) Oil Infrastructure Investment Program (OIIP)

  (ii) Oil and Gas Processing Investment Program (OGPII)

(b) Introduced in 2020, the OIIP has attracted over $76 million in investment in Saskatchewan thus far.

(c) When fully applied it is expected that the OIIP will generate a total investment of at least $500 million that will allow for further adoption of CCUS technologies.

(d) Applications for OIIP will be accepted until March 31, 2025 and credits will expire on March 31, 2035.

(e) The OGPII incentive is able to offer tax credits up to 15% of project costs for eligibility list (list includes CCUS projects).

(f) To meet the eligibility requirements a project must:

  (i) Be a value-added project in any of Saskatchewan's oil, gas, helium, or chemical fertilizer industries.

  (ii) Result in a significant increase to processing capacity.

  (iii) Include at least CAD $10 million in eligible costs.

  (iv) Have not become operational before the eligible project application is submitted.

Quebec

(a) Quebec's EcoPerformance Program looks at reducing the energy consumption and GHG emissions of companies by funding projects related to energy consumption and production as well as process improvements.

(b) Clients that are eligible for this fund include those that use fossil fuels or processes generating fugitive GHG emissions.

(c) As far as funding is concerned, process integration studies may get up to 50% of eligible expenses covered (up to an amount of $100,000 per site for small and medium consumers and up to $300,000 per site for large consumers).

(d) For implementation of projects funding offered can cover up to 75% of eligible expenses, up to a total of $5,000,000 per request and $10,000,000 per site and per year.

Please refer to Appendix B for the list of references used in this section of the report.

Appendix B
References by Section

(a) Section 2

(i) Summary of the Clean Air Act | US EPA

(ii) Table of 100% Clean Energy States - Clean Energy States Alliance (cesa.org)

(iii) What are the Clean Fuel Regulations? - Canada.ca

(iv) Proposed Frame for the Clean Electricity Regulations - Canada.ca

(v) Output-Based Pricing System - Canada.ca

(vi) Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity (justice.gc.ca)

(vii) Coal-fired electricity generation regulations - overview - Canada.ca

(viii) Carbon and Greenhouse Gas Legislation Across Canada: Infographic (osler.com)

(ix) https://www.alberta.ca/carbon-capture-utilization-and-storage-overview.aspx

(x) Funded projects - Province of British Columbia (gov.bc.ca)

(xi) Climate Impact Fund - NBIF

(xii) Province of Manitoba | News Releases | Manitoba Government Invests $1.5 Million in Green Projects through Conservation and Climate Fund

(xiii) Oil Infrastructure Program Expanded to Support Carbon Capture | News and Media | Government of Saskatchewan

(xiv) incentives-helium-ccus-information.pdf (globalenergyshow.com)

(xv) Québec's Ministry of Natural Resources – EcoPerformance (nrcan.gc.ca)

(xvi) Province Invests in Climate Adaptation Projects, Communities - Government of Nova Scotia, Canada

(xvii) Climate Change Challenge Fund (CCCF) - Environment and Climate Change (gov.nl.ca)

(xviii) U.S. State Energy Financial Incentives for CCS - Center for Climate and Energy SolutionsCenter for Climate and Energy Solutions (c2es.org)

(xix) Primer: Section 45Q Tax Credit for Carbon Capture Projects - Great Plains Institute (betterenergy.org)

(xx) What is the Low Carbon Economy Fund? - Canada.ca

(xxi) Output-Based Pricing System Proceeds Fund: Decarbonization Incentive Program - Canada.ca

(xxii) Energy Innovation Program (nrcan.gc.ca)

(xxiii) Investment Tax Credit for Carbon Capture, Utilization, and Storage - Canada.ca

(b) Section 3

(i) Energy storage through Power-to-Fuel technology (climeworks.com)

(ii) http://www.separationprocesses.com/Adsorption/AD_Chp02b2.htm#TopPage

(iii) http://www.separationprocesses.com/Adsorption/AD_Chp02b1.htm

(iv) https://www.babcock.com/home/environmental/decarbonization/oxy-fuel-combustion/

(v) https://ec.europa.eu/research-and-innovation/en/projects/success-stories/all/reaching-new-heights-co2-capture-cement-plants

(vi) Project contents - The project - LEAP s.c.a r.l. - Piacenza (cleanker.eu)

(vii) https://www.iea.org/reports/ccus-in-clean-energy-transitions/ccus-technology-innovation

(viii) https://www.project-leilac.eu/about-leilac

(ix) https://www.drax.com/carbon-capture/what-is-bioenergy-with-carbon-capture-and-storage-beccs/#:~:text=BECCS%20uses%20a%20post%2Dcombustion,then%20be%20transported%20by%20pipeline.

(c) Section 4

(i) https://www.prescouter.com/2022/04/co2-conversion-utilization-pathways/

(ii) Greenhouse Carbon Dioxide Supplementation | Oklahoma State University (okstate.edu)

(iii) Technology — Infinitree LLC

(iv) https://www.bright-renewables.com/carboncapture-technology/

(v) CO2 conversion & utilization pathways: Techno-economic insights - PreScouter - Custom Intelligence from a Global Network of Experts

(vi) About - Carbonfree

(vii) TECHNOLOGY | Blue Planet Systems

(d) Section 5

(i) Noya | Capture CO_2

(ii) Noya: Unlocking the Hidden Potential of Cooling Towers | by Loni Olowookere | Climate Conscious | Medium

(iii) Noya Labs turns cooling towers into direct air capture devices for CO2 emissions | TechCrunch

(iv) https://carbonengineering.com/

(v) LanzaTech

(vi) https://deltacleantech.ca/

Appendix C
List of CCUS Technology Providers (Sent under separate cover as excel folder)

CEM ENGINEERING
Building A More Functional World

Post-Combustion Carbon Capture Companies

#	Method of CO_2 Capture	Company Name	Company Location	Notes	Website
1	Direct Air Capture	Carbon Engineering	Canada	Large Scale Direct Air Capture	Direct Air Capture Technology | Carbon Engineering
2		Climeworks	Switzerland	Large Scale Direct Air Capture	High quality carbon dioxide removal as a service to fight climate change (climeworks.com)
3		Decarbontek LLC	United States		Technology (decarbon.tech)
4		Noya	United States	Small Scale Direct Air Capture	How our DAC solution works | Noya
5		Global Thermostat	United States		Our Solution - Global Thermostat
6		Blue Planet	United States	Large Scale Direct Air Capture	TECHNOLOGY | Blue Planet Systems
7		Neustark	Switzerland		REMOVE | neustark
8		Infinitree	United States		Technology — Infinitree LLC
9		Greencap Solutions	Norway		Industrial Solutions - GREENCAP SOLUTIONS AS, NORWAY | A GREEN CARBON CAPTURE TECHNOL
10		Prometheus Fuels	United States		Technology (prometheusfuels.com)
11	Bioenergy Carbon Capture	Pondtech	Canada	Large Scale Algae Growth	Technology - Pond Tech
12		Hy-Tek Bio	United States	Algae	HY-TEK Bio, LLC. | Unique Algal Strain Technology Provides Components (hytekbio.com)
13		Drax	United Kingdom/North America	Large Scale	BECCS and negative emissions - Drax Global
14		Syncraft	Austria	Conversion of biomass to syngas produces biochar (similar to carbon black) which is a solid fixation of carbon. Allows for carbon negative projects.	Overview of SYNCRAFT® wood power plants
15		CHAR Technologies	Canada	Conversion of biomass to syngas produces biochar (similar to carbon black) which is a solid fixation of carbon. Allows for carbon negative projects.	High Temperature Pyrolysis (HTP) Technology - CHAR Technologies
16		Lanzatech	United States/China/India	Biological capture/utilization of CO2 to create value added products. Lanzatech https://www.energy.gov/sites/prod/files/2017/07/f35/BETO_2017WTE-Workshop_SeanSimpson-LanzaTech.pdf	LanzaTech
17	Physical Separation	Fresme	Europe	Use recycled methanol from residual steel gases as fuel.	PowerPoint Presentation (aspire2050.eu)
18		Decarbontek LLC	United States		Technology (decarbon.tech)
19		Svante	Canada	Traps carbon produced from industrial flue gas emissions generated from the production of cement, steel, ammonia, aluminum, methanol and hydrogen.	Solutions - Svante (svanteinc.com)
20		Global Thermostat	United States	Capturing CO2 directly from Air.	Our Solution - Global Thermostat
21	Membrane Separation	MTR- Membrane Technology Research	United States		Natural Gas Fired Power Plants - Membrane Technology and Research (mtrinc.com)
22		Generon	United States		Carbon Dioxide, CO2 Separation Membrane - Nitrogen & Gas Solutions | GENERON
23		Climeworks	Switzerland		High quality carbon dioxide removal as a service to fight climate change (climeworks.com)
24	Oxy-fuel Separation	Parametric Solutions	United States		Zero Carbon Solution Achieved: Parametric Solutions Enters into Agreement with Natural Resources Canada
25		Linde	United Kingdom		CO_2 plants | Linde Engineering (linde-engineering.com)
26		IHI Corporation	Japan		Carbon Solutions | Resources, Energy and Environment | Products | IHI Corporation
27		Babcock and Wilcox	United States	Via OxyBright system.	Decarbonization Technologies for a Net Zero Future » Babcock & Wilcox
28		Carbon Point	United States	Semi-Closed Cycle (SCC) and CO2-TSA processes enable concentration and capture of CO2 at the distributed power system scale across a broad range of reciprocating engines and gas turbines.	Carbon Capture Technology | CarbonPoint | United States
29	Direct Separation	Calix	Australia	Calix's LEILAC system aims to capture CO2 from cement and lime production using thermal energy.	Calix | Improving the sustainability of water and wastewater treatment
30	Chemical Absorption	Linde	United Kingdom		CO_2 plants | Linde Engineering (linde-engineering.com)
31		Carbon Engineering	Canada	Direct Air Capture (DAC) technology does this by pulling in atmospheric air, then through a series of chemical reactions, extracts the carbon dioxide (CO2) from it while returning the rest of the air to the environment.	Direct Air Capture Technology | Carbon Engineering
32		Aker	Norway & Denmark	Aker Carbon Capture offers standardized carbon capture plants named Just Catch, for delivery of pure CO_2 for various applications. System capacities start at 100,000 tonnes of CO2 capture per year.	Home – Aker Carbon Capture
33		Drax	UK & North America		BECCS and negative emissions - Drax Global
34		Axens	France		Carbon Capture and Storage | Axens
35		Entropy	Canada		Technology - Entropy Inc
36		IHI Corporation	Japan		Carbon Solutions | Resources, Energy and Environment | Products | IHI Corporation
37		Fluor	United States	Econamine FG Plus is Fluor's commercially-proven technology for carbon capture. It offers clients an energy-efficient and cost-effective process for the removal of carbon dioxide from low-pressure, oxygen-containing flue gas streams. The solvent formulation is specifically designed to recover CO2 from streams that are at near-atmospheric pressure. Econamine FG Plus offers a post-combustion CO2 capture option that is easy to retrofit to existing facilities.	Energy Transition (fluor.com)
38		Baker Hughes	United States	Several Carbon Capture solutions using either different solvents or chemical processes to capture CO2. Scale varies based on technology.	Carbon Capture | Baker Hughes Carbon Capture
39		C-Capture	United Kingdom		Technology - C-Capture
40		CO2 Capsol	Norway		Our offerings (co2capsol.com)
41		Bright Renewables	The Netherlands	Offers solution for as low as 12 tonnes per day of Carbon Capture. Systems are somewhat modular.	Bright Renewables | Carbon Capture Technology (bright-renewables.com)
42		Blue Planet	United States	Blue Planet offers a cost-effective technology and process for permanently sequestering and converting CO2 emissions from industrial sources into valuable carbon-sequestered limestone. aggregate products for use in concrete.	9th DC Forum_Blue Planet Tech Talk_3-3-20.pptx (globalccsinstitute.com)
43		Carbon Clean	United Kingdom	Large Scale CO2 capture and reuse cement, refineries, steel.	Next-generation carbon capture technology | Carbon Clean
44	Calcium Looping (Similar to Chemical Looping)	CLEANKER	Italy	One-off demonstration project.	Project contents - The project - LEAP s.c.a r.l. - Piacenza (cleanker.eu)
45		ITRI (Industrial Technology Research Institute)	Taiwan		Calcium-Looping CO₂ Capture Technology-Circular Economy-Sustainable Environment-Innov
46	Chemical Looping	Babcock and Wilcox	United States		Decarbonization Technologies for a Net Zero Future » Babcock & Wilcox
47		CHEERS	China/EU	One-off demonstration project.	CHEERS | Innovation and Networks Executive Agency (archive-it.org)
48		DemoClock	Norway	DemoCLOCK is to demonstrate the technical, economic, and environmental feasibility of implementing packed bed Chemical Looping Combustion in large-scale power plants. A medium sized (500 kW) fixed bed reactor will be designed, build and operated in integration with IGCC power plant of Elcogas in Puertollano, Spain. The Packed Bed Reactor Chemical Looping Combustion (PBR-CLC) will be used to convert carbonaceous feedstock to high energy streams with carbon dioxide capture.	eu-democlock-brochure.pdf (sintef.no)

Pre-Combustion Carbon Capture Companies

#	Pre-Combustion Method	Company	Company Location	Product	Website
1	Methane Pyrolysis	Ekona Power	Canada	Hydrogen and Carbon (solid)	Home | Ekona Power Inc.
2		Monolith	United States	Carbon Black and Hydrogen	Monolith (monolith-corp.com)
3		Hycamite	Finland	Hydrogen and Carbon (solid)	Net Zero & Sustainable Energy Production Solution | Hycamite
4		Czero	United States	Hydrogen and Carbon (solid)	C-Zero | Decarbonizing Natural Gas (czero.energy)
5		HazerGroup	Australia	Graphite and Hydrogen	hazergroup.com.au | Commercialising the Hazer Process
6		Susteon	United States	Hydrogen and Carbon (solid)	Climate Impact Technology Innovations - Susteon Inc.
7		Nu:Ionic	Canada	Hydrogen and Carbon (solid)	Nu:ionic (nuionic.com)
8		Syzygy Plasmonics	United States	Hydrogen and Carbon (solid)	Syzygy Plasmonics
9		New Wave Hydrogen	Canada/United States	Hydrogen and Carbon (solid)	Home - New Wave Hydrogen Inc (newwaveh2.com)
10		HiiRoc	United Kingdom	Hydrogen and Carbon (solid)	Hiiroc
11	Steam Methane Reforming	HoSt Group/HyGear	Netherlands	Hydrogen and CO_2 (gas)	https://hygear.com/technologies/steam-methane-reforming/

Post-Combustion Carbon Capture Companies

#	Method of CO_2 Utilization	Company Name	Company Location	Notes	Website
1	Produce Fuels	Carbon Engineering	Canada	Carbon Engineerings Air to Fuel plants use DAC and electrolysis to obtain CO2 and hydrogen which are then reacted with each other to produce various hydrocarbons. These hydrocarbons are then into various fuels such as gasoline, diesel or jet-fuel.	1. Carbon Engineering | Direct Air Capture of CO2 | Home
2		Air Company	United States	At Air Co., CO2 that has been shipped from industrial plants is used to produce various alcohols and fuels.	1. AIR COMPANY | Carbon Technology Leader for a Decarbonized Future
3		CERT	Canada	CERT uses electrochemical cells to reduce CO2 into a renewable source of fuels and feedstock.	2. CERT Systems Inc (co2cert.com)
4		Topsoe	Denmark	Hydrogen	3. Haldo Topsoe H https://www.topsoe.com/processes/hydrogen
5		Dimensional Energy	United States	Focus is on producing sustainable aviation fuel.	4. Dimensional Energy https://dimensionalenergy.com/
6		Opus 12	United States	PEM Based - CO2 Electrolizer - Fuel Cell	5. Opus 12 https://www.twelve.co/
7		LanzeTech	United States	Lanzatechs carbon recycling program is able to convert CO2 emissions into various fuels and chemicals. Some of their chemical capabilities include producing the following: ethanol, acetone, isopropanol, and monoethylene.	2. LanzaTech
8		Electrochaea	Germany	With their patented biocatalyst Electrochaea is able to take CO2 emissions and H2 to produce natural gas (methane) fuel.	3. Electrochaea GmbH - Power-to-Gas Energy Storage |
9		Prometheus Fuels	United States	Prometheus Fuels removes CO2 from the air and then turns that into gasoline and jet fuel.	4. Prometheus https://prometheusfuels.com/
10		Ineratec	Germany	Capable of producing synthetic hydrocarbons and fuels, as well as other chemical feedstocks.	5. Ineratec https://ineratec.de/en/home/
11		Cemvita Factory	United States	Uses CO2 or CH4 as the feedstock to produce valuable products, such as chemicals intermediates and polymers.	7. Cemvita Factory https://www.cemvitafactory.com/applications/carbon-capture-and-utilization-2
12		Synhelion	Switzerland	Produces gasoline, diesel, or even jet fuel.	6. Synhelion https://synhelion.com/technology
13	Biomass Applications (e.g., Greenhouse Gassing, Carbon Negative Plastics)	Newlight Technologies	United States	As a replacement to plastic, Newlight is able to produce high performance carbon negative plastic.	8. Newlight Technologies https://www.newlight.com/technology
14		CO2 GRO Inc.	Canada/Germany	CO2 GRO Inc. is dedicated to increasing the growth and value of all indoor plants using our advanced CO2 Delivery Solutions™ safely, naturally, sustainably and economically.	6. CO2 Gro Inc https://www.co2gro.ca/
15		BioTherm Solutions	United States	BioTherm's CO2 enrichment technology can capture CO2 from flue gases and release this CO2 in controlled amounts in greenhouses to help improve crop yield.	9. BioTherm Solutions for Greenhouse Growing Technologies
16		Greencap Solutions	Norway	Greencap used adsorption to capture CO2 from the air and then released this CO2 in controlled amounts into greenhouses, to increase crop yield by 40%.	10. Greencap Solutions (greencap-solutions.com)
17		Bright Renewables	The Netherlands	Brights technology is able to capture CO2 from flue gases and then release in greenhouses for crop enhancement.	11. Bright Renewables | Biogas Upgrading, CO2 Capture & Liquefaction (bright-renewables.com)
18		Infinitree	United States	Infinitree systems utilize proprietary technology to concentrate ambient atmospheric CO2 and discharge it within greenhouse environments, enhancing photosynthetic rates and increasing yields. CO2 is sourced on-site from ambient air and can be supplied at any enrichment level. By sourcing CO2 from ambient air, Infinitree systems decrease atmospheric carbon dioxide concentration while providing greenhouse operators with a more cost-effective sourcing option.	12. Infinitree http://www.infinitreellc.com/
19		Carbon Free	United States	SkyCycle is CarbonFree's second-generation technology. Providing a complete CCUS solution, solving the high cost of transport and storage infrastructure. SkyMine is the world's first and largest industrial-scale carbon mineralization facility	13. Carbonfree Chemicals https://carbonfree.cc/our-technologies/
20		Neustark	Switzerland	CO_2NCRETE SOLUTIONS. Neustark removes CO2 from the atmosphere, permanently stores it in recycled concrete, and cuts new emissions by reducing the use of.	14. Neustrark https://www.Neustark.com/
21		Carbon 8	United Kingdom	Carbon 8 captures CO2 and uses it to produce lightweight aggregates and other construction materials.	15. Carbon 8 https://c8s.co.uk/
22		Blue Planet	United States	Blue Planet's technology captures CO2 emissions from flue gases and is able to turn them into valuable building materials such as concrete.	16. Permanent Carbon Capture | Blue Planet Systems | Los Gatos
23		Clean O2	Canada	Captured via CarbinX system (https://www.carbinx.com/). Converts CO2 to Soap.	10. Clean02 www.cleano2.ca (CarbinX)
24		Skyonic	United States	Skyonic is able to capture CO2 emissions from flue gases and turn them into carbon negative products. For example, the solid carbonates and bicarbonates can be sold for use in the production of baking soda, hydrocloric acid and limestone.	17. Skyonic (eaton.com)

#	Method of CO_2 Utilization	Company Name	Company Location	Notes	Website
25	Produce Materials/Chemicals	Hyperion Global Energy	Canada	TANDEM CARBON RECYCLING SYSTEM is housed in a modular, containerized drop-in unit, designed to capture and convert stack emissions directly at the source. Our proprietary process is net carbon negative, efficiently utilizing high volumes of heavy industry emissions – produced by power generation or other industrial processes such as cement and manufacturing – to create valuable materials and revenue streams.	18. Hyperion Global Energy https://hyperionenergy.ca
26		Aether Diamonds	United States	Craft diamonds using carbon that is extracted from the atmosphere.	7. https://aetherdiamonds.com/
27		CarbonCure	Canada	Carbon Cure's technology uses CO2 that has been captured from an industrial process and delivered to site where it is then stored in a tank. The CO2 is then injected into the concrete during mixing to produce a batch with all of the same properties as regular concrete.	8. CarbonCure's Sustainable Concrete Solution - Concrete Technology Reducing Carbon Impact
28		Captico2	Norway		Home | CAPTICO2
29		Carbfix	Iceland		We turn CO2 into stone - Carbfix
30		Carbon Recycling International	Iceland	Produce renewable methanol from carbon dioxide and hydrogen, for more sustainable fuels, chemicals and products.	9. Carbon Recycling International https://www.carbonrecycling.is/
31		Dioxide Materials	United States	Dioxide Materials technology is able to convert CO2 into formic acid, a useful preservative and antibacterial agent.	10. Dioxide Materials https://dioxidematerials.com/technology/formic-acid/
32		Solidia	United States	Solidia is a cement and concrete technology company currently developing innovative solutions to reduce the carbon footprint of concrete products. This is achieved in two (2) ways; 1) Solidia Cement is a non-hydraulic, carbonating cement that is produced at a lower temperature and with less limestone than traditional OPC. The result is ~30% reduction in CO2 emissions. 2) Solidia Cement is then used in the production of concrete products which are cured with CO2, permanently mineralizing the CO2 during the harding process.	11. Solidia https://www.solidiatech.com/
33		Carbon Upcycling	Canada	Technology works by taking industrial byproducts or natural minerals and combining them with a CO2 source (either from low or high-purity CO2 sources) in our large catalytic reactors.	Technology - Carbon Upcycling
34		C2NT	Canada	C2NT takes captured CO2 and is able to produce lightweight, high strength carbon nanotubes.	12. Our mission – Removing anthropogenic carbon dioxide and pioneering a transformative nano carbon economy (c2cnt.com)
35		Carbicete	Canada	Carbon Curing: Our patented curing process involves the injection of CO2 into an absorption chamber where it reacts with the steel slag within the fresh concrete. During the carbonation process, the CO2 is permanently captured and converted into stable calcium carbonates, filling the voids of the matrix to form a dense structure and giving the concrete its strength.	13. Carbicete https://carbicrete.com/technology/
36		Carbon Nova	Canada	Capable of producing high volume carbon nanofibers using CO2.	14. Carbon Nova Corp https://www.carbonova.com/

Appendix D
Financial Feasibility Tool (Sent under separate cover as excel folder)

Energy Solutions Center

Gas Turbine Generator (GTG)

Prime Mover Details		
Prime Mover	5 MWe Gas Turbine Generator (GTG)	
Air Inlet Temperature	60	°F
Nominal Output Power @ Terminals	4,962	kWe
Fuel Input Energy (LHV)	57.4	mmBtu/hr
Air Inlet Flow	159,146	lbm/hr
Exhaust Gas Temperature	958	°F
Exhaust Gas Mass Flow Rate	161933	lbm/hr
Nominal Electric Heat Rate at Terminals	11575	Btu/kWh
Unfired Steam flow	30026	lbm/hr
Technical Assumptions		
Nominal Generating Capacity	4,962.0	kWe
Average Gross Power Output	4,962.0	kWe
Parasitic Power Load	2%	
Average Net Power Output	4,862.8	kWe
Operating Hours	8,000.0	hr/yr
Natural Gas Emission Intensity	53	kg/mmBtu
HHV to LHV Ratio	1.11	
Electrical Analysis		
Annual Incremental Electricity Use	70	kWh/tonne CO_2
Thermal Analysis		
Incremental Steam Energy Required	11	mmBtu/hr
Natural Gas Boiler Efficiency	80%	
Incremental Natural Gas Required	13	mmBtu/hr (HHV)
Annual Technical Results		
Annual Incremental Electricity Use	1,703,632	kWh/yr
Net Annual CO2 Captured	24,338	tonnes/yr
Carbon Capture Efficiency	90	%
CO2 Captured per day	81	tonnes/day
Annual Incremental Fuel Consumption	107,310	mmBtu/yr
Financial Assumptions		
Purchase Price of Electricity	0.10	$/kWh
Burner Tip Cost of Natural Gas	0.22	$/m^3
Burner Tip Cost of Natural Gas	6.0	$/mmBtu
Annual Maintenance Rate	0.5%	% of Capital
Carbon Price/ Tax	110	$/Tonne CO2
Value of Carbon Sold	40	$/Tonne CO2
OPEX of CO2 captured	36	$/Tonne CO2
Weighted Average Cost of Capital	4.5%	
Assumed Capital Cost (Design, Supply, Install, Commission)	12,931	$000's
Proforma Analysis ($000's CAD)		
Carbon Tax Savings	$ 2,677	
Revenue from CO2 Sales (If Applicable)	$ 974	
Total Incremental Annual Savings	**$ 3,651**	
Incremental Steam Usage	$ 641	
Incremental Electricity Usage	$ 170	
Annual Maintenance Costs	$ 65	
Total Incremental Annual Operational Expenses	**876**	
Net Annual Savings (Before Tax, Before Financing)	**$ 2,775**	
Capital Cost (Design, Supply, Install, Commission)	12,931	$000's
Simple Payback	4.7	years

Energy Solutions Center

Water Tube Boiler

Prime Mover Details		
Prime Mover	250,000 lb/hr O-Type Water Tube Boiler	
Max Inlet Fuel Flow	315	mmBtu/hr (HHV)
Average Inlet Fuel Flow	145	mmBtu/hr (HHV)
Maximum Outlet Steam Flow	250,000	lbm/hr
Maximum Allowable Working Pressure (MAWP)	800	psig
Boiler Efficiency	84%	
Steam Temperature	600	°F
Steam Pressure	400	psig
Technical Assumptions		
Operating Hours	8,000	hr/yr
Fuel Input	0.0101	mmBtu/lb
Emissions Factor of Natural Gas	53	kg of CO2/mmBtu
HHV to LHV Ratio	1.11	
Electrical Analysis		
Annual Incremental Electricity Use	70	kWh/tonne CO_2
Thermal Analysis		
Incremental Steam Energy Required	27	mmBtu/hr
Natural Gas Boiler Efficiency	84%	
Incremental Natural Gas Required	32	mmBtu/hr (HHV)
Annual Technical Results		
Annual Incremental Electricity Use	4,303,600	kWh/yr
Net Annual CO2 Captured	61,480	tonnes/yr
Capture Efficiency	90	%
CO2 Captured per day	205	tonnes/day
Annual Incremental Fuel Consumption	257,253	mmBtu/yr
Financial Assumptions		
Purchase Price of Electricity	0.10	$/kWh
Burner Tip Cost of Natural Gas	0.22	$/m^3
Burner Tip Cost of Natural Gas	6.0	$/mmBtu
Annual Maintenance Rate	0.5%	% of Capital
Carbon Price/ Tax	60	$/Tonne CO2
Value of Carbon Sold	40	$/Tonne CO2
OPEX of CO2 captured	35	$/Tonne CO2
Weighted Average Cost of Capital	4.5%	
Assumed Capital Cost (Design, Supply, Install, Commission)	38,337	$000's
Proforma Analysis ($000's CAD)		
Carbon Tax Savings	$ 3,699	
Revenue from CO2 Sales (If Applicable)	$ 2,459	
Total Incremental Annual Savings	**$ 6,158**	
Incremental Steam Usage	$ 1,536	
Incremental Electricity Usage	$ 430	
Annual Maintenaince Costs	$ 192	
Total Incremental Annual Operational Expenses	**$ 2,158**	
Net Annual Savings (Before Tax, Before Financing)	**$ 4,000**	
Capital Cost (Design, Supply, Install, Commission)	38,337	$000's
Simple Payback	9.6	years

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Large ICE Generator

Prime Mover Details		
Prime Mover	3.3 MWe Engine (Natural Gas Fueled) with Generator	
Air Intake Temperature	91.4	°F
Exhaust Flue Gas Temperature	693.0	°F
Exhaust Gas Flow	41,050.0	lbm/hr
Specific fuel consumption of Engine	2.14	kWh/kWh
Energy Input	7,357.0	kW
Energy Output	5,062	kW
Stack Temperature	411.0	°F
Technical Assumptions		
Nominal Generating Capacity	3,300.0	kWe
Average Gross Power Output	3,300.0	kWe
Parasitic Power Load	2%	
Average Net Power Output	3,234.0	kWe
Operating Hours	8,000.0	hr/yr
Emissions factor of Natural Gas	53	kg of CO2/mmBtu
HHV to LHV Ratio	1.11	
Electrical Analysis		
Annual Incremental Electricity Use	70	kWh/tonne CO_2
Thermal Analysis		
Incremental Steam Energy Required	5	mmBtu/hr
Natural Gas Boiler Efficiency	80%	
Incremental Natural Gas Required	6	mmBtu/hr (HHV)
Annual Technical Results		
Annual Incremental Electricity Use	745,060	kWh/yr
Net Annual CO2 Captured	10,644	tonnes/yr
Capture Efficiency	90	%
CO2 Captured Daily	35	tonnes/day
Annual Incremental Fuel Consumption	46,931	mmBtu/yr
Financial Assumptions		
Purchase Price of Electricity	0.10	$/kWh
Burner Tip Cost of Natural Gas	0.22	$/m^3
Burner Tip Cost of Natural Gas	6.0	$/mmBtu
Annual Maintenance Rate	0.5%	of Capital
Carbon Price/Tax	110	$/Tonne CO2
Value of Carbon Sold	-	$/Tonne CO2
OPEX of CO2 captured	37	$/Tonne CO2
Weighted Average Cost of Capital	4.5%	
Assumed Capital Cost (Design, Supply, Install, Commission)	7,643	$000's
Proforma Analysis ($000's CAD)		
Carbon Tax Savings	$1,171	
Revenue from CO2 Sales (If Applicable)	$0	
Total Incremental Annual Savings	**$1,171**	
Incremental Steam Usage	$280	
Incremental Electricity Usage	$75	
Annual Maintenance Costs	$38	
Total Incremental Annual Operational Expenses	**$393**	
Net Annual Savings (Before Tax, Before Financing)	**$778**	
Capital Cost (Design, Supply, Install, Commission)	7,643	$000's
Simple Payback	9.8	years

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Industrial Process Dryer

Prime Mover Details		
Process Unit	45' Industrial Process Dryer with Regenerative Thermal Oxidizer (RTO)	
Evaporation Rate (Water Removed)	32,000	lb/hr
RTO Exhaust Flow Rate	38,000	acfm
Technical Assumptions		
Natural Gas Usage	45	mmBtu/hr
Operating Hours	8,000	hr/yr
Capture Efficiency	90	%
Carbon Capture Unit Capacity	64	tonnes/day
Carbon Emission Factor - Grid Electricity	500	tonnes/GWh
Carbon Emission Factor - Displaced Natural Gas	53	kgCO2/mmBtu (HHV)
Electrical Analysis		
Annual Incremental Electricity Use	70	kWh/tonne CO_2
Thermal Analysis		
Incremental Steam Energy Required (50 psig steam)	8	mmBtu/hr
Natural Gas Boiler Efficiency	80	%
Incremental Natural Gas Required	11	mmBtu/hr (HHV)
Annual Technical Results		
Annual Incremental Electricity Use	1,484,000	kWh/yr
Annual Incremental Fuel Consumption	84,128	mmBtu/yr
Annual Net CO_2 Savings	15,999	Tonnes/yr
Financial Assumptions		
Purchase Price of Electricity	0.10	$/kWh
Burner Tip Cost of Natural Gas	0.22	$/m^3
Burner Tip Cost of Natural Gas	6.0	$/mmBtu
Annual Maintenance Rate	0.5	% of Capital
Carbon Price	110	$/Tonne CO2
Value of Carbon Sold (i.e., Value of Utilized Carbon vs. Stored)	-	$/Tonne CO2
OPEX of CO2 captured	44	$/Tonne CO2
Weighted Average Cost of Capital	4.5%	
Assumed Capital Cost (Design, Supply, Install, Commission)	11,500	$000's
Proforma Analysis ($000's CAD)		
Carbon Tax Savings	1,760	
Revenue from CO_2 Sales	-	
Total Incremental Annual Savings	**1,760**	
Incremental Steam Usage	502	
Incremental Electricity Usage	148	
O&M	58	
Total Incremental Annual Operational Expenses	**708**	
Net Annual Savings (Before Tax, Before Financing)	**1,052**	
Capital Cost (Design, Supply, Install, Commission)	11,500	
Simple Payback	10.9	years

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Natural Gas Prices

Assumed a escalation rate of 2% unless otherwise stated

Natural Gas Price Forecast for North America

		Year:	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
	Regions:	-	-	-	-	-	-	-	-	-	-	-	-
	Texas (US $/mmBtu)	-	8.72	8.89	9.07	9.25	9.44	9.62	9.82	10.01	10.21	10.42	10.63
West Coast States	California (US $/mmBtu)	-	13.65	13.93	14.21	14.49	14.78	15.08	15.38	15.69	16.00	16.32	16.65
	Oregon (US $/mmBtu)	-	14.88	15.18	15.48	15.79	16.11	16.43	16.76	17.09	17.43	17.78	18.14
	Washington (US $/mmBtu)	-	7.93	8.09	8.25	8.41	8.58	8.75	8.93	9.11	9.29	9.47	9.66
Midwest States	Illinois (US $/mmBtu)	-	8.88	9.06	9.24	9.43	9.61	9.81	10.00	10.20	10.41	10.61	10.83
	Michigan (US $/mmBtu)	-	9.66	9.86	10.05	10.25	10.46	10.67	10.88	11.10	11.32	11.55	11.78
	Ohio (US $/mmBtu)	-	12.67	12.92	13.18	13.45	13.72	13.99	14.27	14.56	14.85	15.14	15.45
Eastern Seaboard	New York (US $/mmBtu)	-	23.68	24.16	24.64	25.13	25.64	26.15	26.67	27.21	27.75	28.30	28.87
	Pennsylvania (US $/mmBtu)	-	10.41	10.62	10.84	11.05	11.27	11.50	11.73	11.96	12.20	12.45	12.70
	Massachusetts (US $/mmBtu)	-	22.81	23.26	23.73	24.20	24.69	25.18	25.68	26.20	26.72	27.26	27.80
East Coast	New Brunswick (CDN $/GJ)	-	15.11	15.41	15.72	16.03	16.36	16.68	17.02	17.36	17.70	18.06	18.42
	Nova Scotia (CDN $/GJ)	-	22.45	22.90	23.36	23.82	24.30	24.79	25.28	25.79	26.30	26.83	27.37
Western Canada	Alberta (CDN $/GJ)	Per AECO forcast	6.19	5.62	5.45	5.64	5.84	6.05	6.27	6.50	6.73	6.96	7.96
	British Columbia (CDN $/GJ)	-	5.91	6.03	6.15	6.27	6.40	6.53	6.66	6.79	6.92	7.06	7.20
	Ontario (CDN $/GJ)	-	7.20	7.34	7.49	7.64	7.79	7.95	8.11	8.27	8.44	8.60	8.78