

The Feasibility of Implementing Carbon Capture and Storage at Yale

Annie Bui

Advisor: Michael Oristaglio

2nd Reader: Jay Ague

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Annie Bui, May 05, 2017

Abstract

This senior thesis examines the feasibility and cost of implementing capture and storage of the carbon dioxide (CO₂) that is currently released to the atmosphere by the power plants providing most of the electricity, heating and cooling on the Yale University main campus. The two facilities are Yale Central Power Plant and Yale Sterling Power Plant. After a review of the background and current state of carbon capture and storage as a technology for mitigating climate change, the paper uses the Yale plants as examples for a calculation of the costs associated with all phases of this process, including capturing CO₂ from the flue gas, compressing it to a supercritical fluid, transporting the fluid to a storage site, and injecting it into an underground geologic formation. To estimate transportation and storage costs, we consider storage in the Mt. Simon Sandstone Formation in the Illinois Basin. The Mt. Simon formation is one of the closest underground injection sites that have been proposed and studied for safe, long-term storage of captured carbon in deep saline aquifers (Breunig et al., 2012). No similar sites in the Northeastern United States have been as extensively studied. Finally, I estimate the monetary and energy costs of the full cycle of CCS.

However, a recent research project at Yale looked at the feasibility of injecting CO₂ into basaltic rocks, which are abundant in the Northeast, in a type of carbon sequestration called mineral carbonation. This process converts the injected fluid CO₂ into solid minerals by reaction with other minerals in the host rock, and can be considered a truly permanent form of sequestration. As part of the work in this thesis, I developed a simple reaction model to try to better understand the results of the laboratory studies of carbonation reactions with the mineral olivine, which were carried out on Yale West Campus from 2011 to 2016 in a project sponsored by the U.S. Department of Energy (Wang et al., 2016).

Background

In 2015, fossil fuels made up 81.5% of total U.S. energy consumption and about 80.1% of the world's total energy consumption (IEA, 2016). With abundant supplies still available (BP, 2016), fossil fuels are projected to remain the

U.S. energy consumption by energy source, 2015

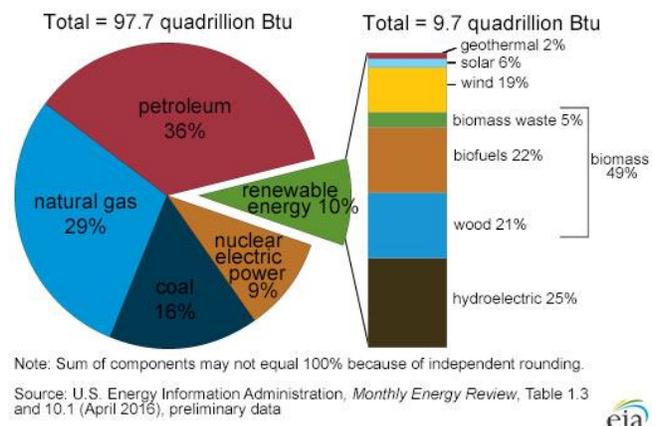


Figure 1: US energy consumption in 2015

dominant source of energy through at least the first half of the 21st century. Fossil fuels still have many advantages over renewables forms of energy, including relatively low cost, high energy density, existing infrastructure, and ease of use and storage. Fossil fuels have afforded many countries with high standard of living. The benefits of fossil fuels must, however, be critically weighed with the costs associated with the greenhouse gases and pollutants that they emit. These emissions have adverse environmental, economic, and human health effects, including the effects of anthropogenic climate change.

The most important greenhouse gas in Earth's atmosphere is carbon dioxide (CO₂). And, the major source of anthropogenic CO₂ is combustion of fossil fuels. A transition to low-carbon energy throughout the world will likely require decades, and perhaps even centuries, to unfold. Given that existing fossil fuel power plants provide 65% of the total generated power in the US, any reasonable strategy for mitigating anthropogenic climate change must incorporate technologies that cut greenhouse gas emissions without shutting down these plants (IPCC, 2014). Technological solutions and mitigation strategies are necessary to reduce the concentration of atmospheric carbon dioxide and ultimately combat climate change. The International Energy Agency projects that international 14% reduction of CO₂ emissions in 2050 will be through application of CCS technology (IEA, 2016).

CCS in The Context of International Climate Agreement to Achieve A 2°C Scenario

The Paris Agreement represents a clear commitment from the world's political leaders to transition to a low-carbon economy. The agreement focuses on climate mitigation strategies after 2020. Achieving the ambitious goals of the Paris Agreement necessitates implementation of CCS among other climate mitigation actions. The new approach adopted for the post-2020

climate agreement has evolved since the pre-2020 agreement under the Kyoto Protocol and incorporates a “bottom-up” approach expected to secure a greater level of climate action through intended nationally determined contributions (INDCs).

The Paris Agreement defines a number of ambitious climate goals. A short-term goal is reaching peak emissions as soon as possible. Article 2 defines goals for “holding the increase in the global average temperature to well below 2°C above pre-industrial times and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change” (Paris Agreement, 2015).

Global modelling efforts by the IPCC and the IEA underscore CCS as a critically important mitigation technology that can help countries meet the level of global emissions reduction goals set by the Paris Agreement. The IPCC Climate Change 2014: Synthesis Report Summary for Policymakers compared the costs of achieving 450 parts per million (ppm) CO₂ equivalents by 2100 with scenarios that include CCS, and concluded that the cost without CCS would be 138% more costly and that only a minority of climate model runs could successfully produce a 450 ppm without CCS (IPCC, 2014). Since climate models indicate that the 450 ppm atmospheric concentration threshold will likely be exceeded in the absence of CCS, there will be a stressed need for even more net-negative mitigation climate action in the post-2050 period. Net-negative technologies, such as bio-energy coupled with CCS (BECCS) face even more obstacles to large-scale deployment. Given the political uncertainty regarding the EPA and President Trump’s willingness to adhere to the Paris Climate Agreement, there are still questions surrounding the United States’ commitment to climate action. Given the likelihood of a carbon

budget overshoot, especially for a “well below a 2°C target”, research and development in CCS technologies should be prioritized among climate mitigation technologies. Achieving the goals of the 2°C Scenario will be very challenging. Substantially curbing emissions is necessary to address the rapid rise in average global temperature from current greenhouse gas emissions, as well as “warming in the pipeline.”

The global emissions from the energy sector in 2016 was 32.1 gigatonnes of CO₂ (IEA Newsroom, 2017). IEA projections for a least-cost pathway to reach a 2°C Scenario would need capture and storage of approximately 4,000 million tonnes of CO₂ per year in 2040. This would be 100 times the expected annual CO₂ capture capacity by the end of 2017 (IEA, 2016). Carbon capture and storage (CCS) is the only current technology that can deliver significant emissions reduction from anthropogenic greenhouse gas sources. CCS can reduce emissions from industrial sectors such as cement manufacturing, petrochemical, iron and steel, and refining. Based on emissions reduction models by the International Energy Agency, CCS could deliver 13% of the cumulative emission reductions needed by 2050 to limit the global temperature increase to 2°C.

Another argument to include CCS in international climate dialogue is that renewable energy and energy efficiency alone is not enough to meet the 2°C target. Fossil fuels has been so embedded in the power sector, especially due to already existing infrastructure of power plants, distribution, and transmission systems built around the use of fossil fuels. Additionally, since so much of the capital stock (existing quantity of capital in a given region, including manufactured, human, and natural capital) and infrastructure of modern economic systems are

based on fossil fuel use, the transition from reliance on fossil fuels will require large restructuring and new investment (Harris & Roach, 2017).

The world has a massive emissions potential from existing and future fossil fuel power plants. According to CoalSwarm Global Coal Plant Tracker, there are over 2000 coal-fired power plants that are under construction or in various stages of development planning around the world. There were over 100,000 newly operating coal plants by year 2015 and 75,000 coal plants by 2016.

Besides coal fired power plants, natural gas power plants can also benefit from CCS in reducing emissions. Non-power industry accounts for approximately a quarter of global CO₂ emissions. In cases where renewable energy cannot serve as mitigation substitutes for CCS in industrial sectors, CCS technologies can significantly reduce direct emissions from these industrial processes.

The U.S. Inventory of Greenhouse Gas Emissions and Sinks estimates that more than 40% of CO₂ emissions in the United States are from electric power generation. Use of CCS at a 500 MW coal-fired power plant, which emits roughly 3 million tons of CO₂ per year, can reduce 90% of the emissions. This is equivalent to planting more than 62 million trees, and waiting at least 10 years for them to grow, or to eliminating the annual electricity-related emissions from more than 300,000 homes (EPA, 2017). There are still many challenges in its widespread use on a scale that would meaningfully mitigate climate change.

One challenge is economic. Aside from the cost of the capture equipment itself, the capture process with current technology can use up to 30% of the energy from a power plant (Celia, 2015). This high-energy demand of CO₂ capture translates into high costs. Injecting large

volumes of CO₂ into subsurface geologic formations have potential environmental consequences. There is low public trust regarding the safety and sustainability of CCS (Huijts et al., 2007), therefore CCS technologies should be further investigated to determine the physical and economic feasibility of the process.

Carbon Capture and Storage

Carbon capture and storage is really a collection of technologies that have been proposed to prevent man-made CO₂ from having harmful effects on Earth's atmosphere. The phrase itself is usually abbreviated as "CCS". The abbreviation "CCUS" is also used in a similar way for "carbon capture, utilization and storage". In this paper, I will use CCS for simplicity. CCS technologies can be considered a form of geoengineering that would allow industrialized and developing countries to mitigate the harmful effects of CO₂ and pollutants while transitioning to a fully decarbonized world. An extreme form of CCS would involve capturing CO₂ directly from the atmosphere to reduce or hold steady its atmospheric concentration. This is usually called "direct capture" and is a more aggressive (and difficult) form of geoengineering. In this paper, I will focus on technologies that capture CO₂ at man-made point sources such as power plants.

CCS technologies in power plants capture gaseous CO₂ generated by the combustion of coal, oil or natural gas in the electrical turbine (post-combustion capture) or by processing of the input fuel before combustion (pre-combustion capture). This paper considers only post-combustion capture, in which carbon dioxide is filtered from the flue gas before it is vented to the atmosphere. CCS also has applications in industrial processes, such as cement, iron, and steel manufacturing. Ultimately the aim is to store the captured carbon in a stable geological

site. The overall goal is to develop the process to a point where it is cost-effective and environmentally sound.

In typical CCS operations, the captured gaseous CO₂ is pressurized to approximately 100 bar and transported as a supercritical fluid (refer to CO₂ phase diagram) to the storage location – a stable geological site that can store CO₂ for long periods of time. In conventional storage, the fluid CO₂ is injected into an underground reservoir, such as a saline aquifer or a depleted hydrocarbon reservoir, where it displaces the native fluids in the pore space of the rocks, but is (ideally) trapped underground for centuries by impermeable rocks that bound the reservoir. In mineral carbonation, the CO₂ is injected into rocks containing minerals that react with fluid CO₂ to form solid carbonate minerals. Mineral carbonation in principle overcomes any risks associated with leakage of fluid CO₂ from the underground storage back into the atmosphere.

The sections that follow briefly describe the different steps in CCS.

The Steps of CCS

CCS involves three main steps: 1) Capture of CO₂ from power plants or industrial processes, 2) Transport of the captured and compressed CO₂ (usually in pipelines), and 3) Underground injection and geologic sequestration (storage) of the CO₂ into deep geological formations (EPA, 2017).

1. Carbon Capture Technology

Amine scrubbing has been used to separate CO₂ from hydrogen and natural gas since 1930. Monoethanolamine (MEA) is made from ammonia and ethylene oxide. Amine scrubbing is a viable technological solution for post-combustion capture of CO₂ to directly reduce emission

of CO₂. Examining the amine scrubbing process will elucidate the multiple components necessary for retrofitting existing power plants and the costs in later section.

The description of an amine-based CO₂ capture system is based on a report published by Hitachi Power Systems America, Ltd. (Eswaran, Wu, & Nicolo). Main system components are a polishing scrubber, absorber, desorber, reboiler, and reclaimer. Flue gas from the power plant is sent to the polisher scrubber to reduce SO₂ and SO₃ to below 10 ppm and cool the flue gas to 40-60°C for maximum CO₂ capture in the absorber. Caustic soda (NaOH) solution removes SO_x and minimize production of heat-stable salts in the downstream absorber-desorber loop. The clean and cool flue gas exiting the polishing scrubber is sent to the packed bed absorber where it reacts with the amine-based solvent. Solvent solution is added into the top of the packing layers and collected at the bottom. Inter-stage cooling heat exchangers are used to maintain optimum absorber temperature because CO₂ absorption is an exothermic reaction. The flue gas depleted of CO₂ exits the top of the absorber and escapes through the stacks. The solution rich in CO₂ exiting the bottom of the absorber enters a desorber through a cross heat exchanger. The packed-bed desorber strips pure CO₂ gas from the CO₂-rich solution by contacting the solution with steam in a countercurrent direction. Some of the solution at the bottom of the desorber circulates through a reboiler, which uses auxiliary steam to partially vaporize the amine solution. When the amine solution returns to the desorber, it provides the necessary heat to regenerate amine and release CO₂. Regenerated solvent is sent again to the absorber after it's cooled in the cross-heat exchanger. Reclaimers can control the heat-stable salt level in the system.

A second CO₂ separation technology uses solvent supported membranes and solvents, such as ionic liquids and deep eutectic solvents for natural gas-fired combined cycle power plants. The technology uses a two-membrane system, with the first one separating CO₂ for final sequestration and the second one to generate a selective CO₂-rich flue gas recycle (Voleno et al., 2014). The process of CO₂ separation with membranes is advantageous in that it does not require additional water consumption or steam for regeneration, which would not affect steam turbine operations in power plants. These CO₂ membranes can be utilized in energy intensive industries for both post-combustion and pre-combustion separators.

There are still technical challenges to improving membrane permeability and selectivity, which requires limiting the area needed for a given separation efficiency and obtaining a high purity of the CO₂ separated (Voleno et al., 2014). Solvent supported membranes employ solvents that have negligible volatility and can provide the necessary selectivity for the porous membrane. These CO₂ membranes can be integrated into post-combustion capture systems in power plants. Since the flue gas from natural gas combined cycle power plants contain less CO₂ content compared to coal plants, the capture process can be more efficient by increasing the CO₂ concentration in the membrane feed by a technology proposed by (Merkel et al., 2010).

2. Transportation

CO₂ must be transported to a storage site for sequestration once it is captured and compressed. The primary option for large scale transport is through pipelines, and the secondary option is through shipping [Naucler et al., 2008]. Transporting large quantities of CO₂ is most economical with pipelines. The pipelines must ensure that the CO₂ remains above its critical pressure by recompressing the CO₂ at certain points along the length of the pipeline,

which is necessary for pipelines over 150km in length or if the pipe is too small in diameter (Herzog, 2011).

According to Wong, liquefied CO₂ can be transported via motor vehicles, such as tank trucks and stored in cryogenic vessels. The tank trucks have an inner vessel or “liquid container” that is surrounded and supported by an outer vessel or “vacuum jacket” (Wong, 2006). The liquid CO₂, is typically at 1.7 MPa and -30 degrees C. The vessels come in various sizes, ranging from 2 to 30 tonnes of CO₂.

Ocean transport has been in operation for long distance transport of CO₂ through oceans. The ship sizes are 1,500 m³ with transport pressure of 1.4 to 2 MPa. However, these ships are not appropriate for large-scale shipments of CO₂ for CCS because these ships must be modified as pressure vessels. Current tankers are currently used for shipping liquefied petroleum gas, which could be adapted for shipping CO₂.

3. Saline Aquifers

CO₂ injection into deep saline aquifers provides one of four main options for geological storage of CO₂. Saline formations are deep sedimentary rocks saturated with waters or brines with high concentrations of dissolved salts (IPCC, 2005). Though these formations contain large volumes of water, the brine is unsuitable for agriculture or human consumption. Saline brines can be utilized in producing low-enthalpy geothermal energy. Regions with good geothermal energy potentially will be less favorable for CO₂ geological storage because of the high degree of faulting and fracturing, and sharp increase of temperature with depth (IPCC,2005).

CO₂ can be injected into poorly cemented sands approximately 800 to 1000 meters below the sea floor. Saline formations are made of sandstone that is porous and therefore, able

to hold CO₂. Overlying these formations are impermeable, non-porous layers of rock, such as a thick shale or clay layer that trap the CO₂ and prevent it from migrating upward. After CO₂ is injected, the saline formation must be monitored by seismic time-lapse surveys, which can indicate any upward migration of CO₂ due to buoyancy forces.

The Sleipner Project in the North Sea is one of the best examples of a successful CO₂ storage project in saline formation. The Sleipner Project was the first commercial-scale geological CO₂ storage project and has injected 1 Mt of CO₂ annually, starting in October 2009 (IPCC, 2005). Surveys from the Sleipner Project show that caprock prevents migration of CO₂ out of the saline formation. Reservoir studies and simulations show the CO₂-saturated brine will become denser and sink, thus eliminating the possibility of leakage (Lindeberg and Bergmo, 2003).

According to studies between 2003 and 2007, deep saline aquifers have the highest potential CO₂ storage capacity, compared to storing CO₂ in depleted oil and gas fields (Bachu, 2003; IPCC, 2005; Bradshaw *et al.* 2007). Existing storage projects have demonstrated that CO₂ storage in deep saline aquifers is a successful technology that can be safely applied today. Estimated storage capacity suggest deep saline aquifers can store emissions from large stationary sources (fossil fuel-based electric power generation plants and steel and cement plants) for at least a century (Celia *et al.*, 2015), which makes CCS an important bridging technology in the transition to a carbon-free energy source.

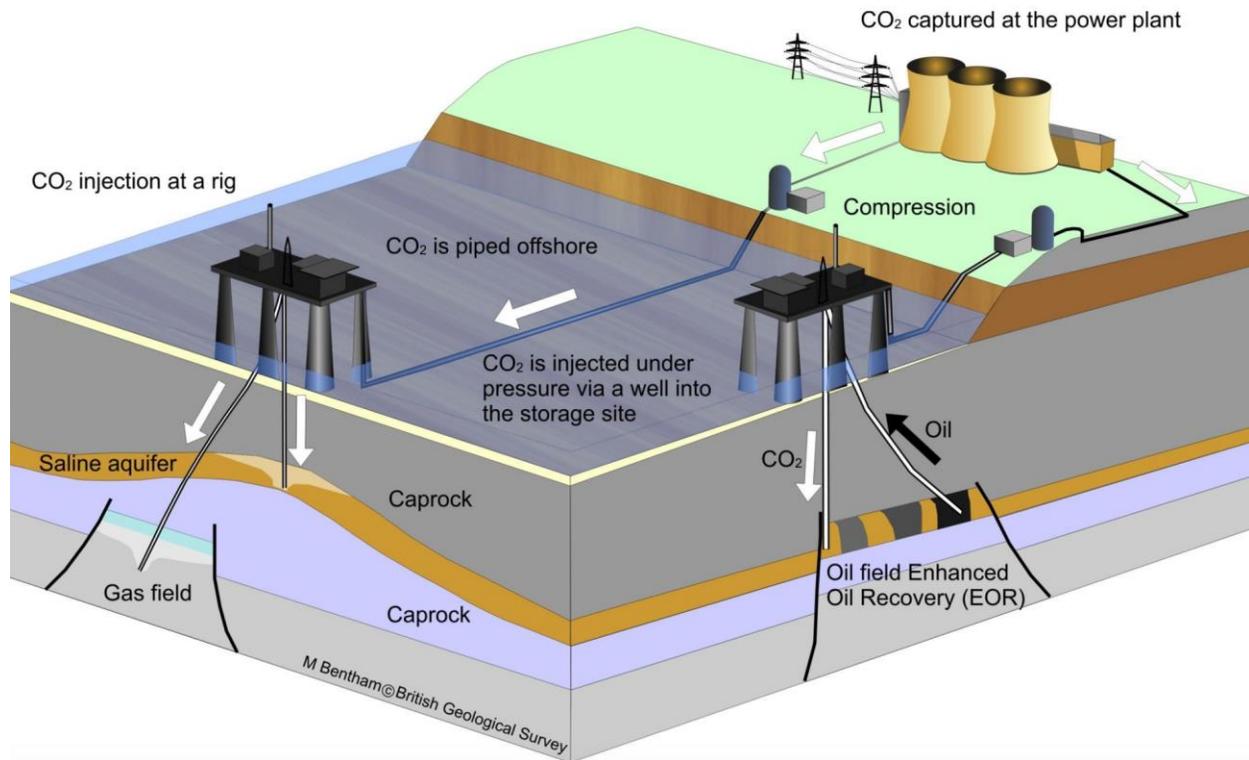


Figure 2: Schematic of CCS

Applications of CCS

According to the EPA's Greenhouse Gas Reporting Program, CO₂ capture is currently occurring at over 120 facilities in the United States. CO₂ capture has been used mainly on industrial processes other than power generation, such as cement manufacturing. The captured CO₂ from industrial processes is used for a wide range of end uses, including enhanced oil recovery (EOR), food and beverage manufacturing, pulp and paper manufacturing, and metal fabrication (EPA, 2017).

In the absence of measures to limit CO₂ emissions and carbon pricing, there are still only small and niche opportunities to deploy CCS technologies. However, application CCS in enhanced oil recovery has made CCS more economically attractive (DOE, 2010). Most successful projects and those in development planning have had strong links to the oil and gas industry. These industries can either provide the source of CO₂ or use the CO₂ for EOR applications that can increase the economic feasibility of CCS.

Enhanced Oil Recovery

Crude oil development and production can have up to three distinct phases. The primary recovery uses the natural pressure of the reservoir or gravity to drive oil into the wellbore, as well as artificial lift techniques to extract the oil. The secondary recovery aims to extend a field's productivity by injecting water or gas and displacing oil to drive it to a production wellbore. This results in a recovery of 20 to 40% of the original oil in place. The tertiary or enhanced oil recovery techniques can produce 30 to 60% of a reservoir's original oil. EOR is utilized when easy-to-produce oil has already been recovered from US oil fields (DOE Office of Fossil Energy). By 2010, there were about 114 active commercial CO₂ injection projects that cumulatively injected over 2 billion cubic feet of CO₂ to produce over 280,000 BOPD (April 19, 2010, Oil and Gas Journal).

CO₂ EOR is attracting new market interests because injecting CO₂ extends a field's productive life. For example, the Dakota Gasification Company's plant in Beulah, North Dakota produces and delivers CO₂ by a 204-mile pipeline to the Weyburn oil field in Saskatchewan, Canada. CO₂ EOR is expected to extend the field's productive life by 25 years and add 130 million barrels of oil that would have otherwise been abandoned (DOE, 2010).

According to the Global CCS Institute, enhanced coal bed methane (ECBM) recovery can produce additional coalbed methane from source rock. This method is similar to EOR. CO₂ is injected into bituminous coal bed, which then occupies the pore space. CO₂/nitrogen injection into coal seams can be economic if the value of the produced gas exceeds the cost of producing the gas, plus the cost of transporting the gas minus the cost of taxes or CO₂ credits.

The Calera process captures and sequesters CO₂ from power plant emissions, post-combustion and store it in a mineralized stable form. The process reacts flue gas from fossil fuel combustion with alkaline solutions heavy in calcium and/or magnesium and forms a stable carbonate solid. The byproduct is relatively fresh water that could be desalinated. The CO₂ absorbed into a bicarbonate solution can be stored underground. The bicarbonate solution can be transformed into carbonate material, which can be stored or turned into supplementary cementitious material (SCM).

Review of Previous Studies on CCS

1. Snøhvit CO₂ Storage Project: operating on the Norwegian coast. The Snøhvit CO ₂ Storage Project located offshore Norway has injected more than three million tonnes of CO ₂ .
2. Santos Basin Pre-Salt Oil Field CCS Project: operating off the coast of Rio de Janeiro in ultra-deep water, has injected three million tonnes of CO ₂ into producing reservoirs as of December 2015.
3. Air Products Steam Methane Reformer EOR Project: operating in Texas, has captured more than three million tonnes of CO ₂ from hydrogen production facilities and used for EOR, as of June 2016
4. Boundary Dam Carbon Capture and Storage Project: captured one million tonnes of CO ₂ from its power generation facility and used for EOR, as of July 2016
5. Quest Project: operating in Alberta, Canada; captured CO ₂ from a hydrogen-processing plant and stored more than one million tonnes of CO ₂ into deep saline formation as of September 2016
6. DOE's Clean Coal Research, Development and Demonstration Programs: injected over 13 million tonnes of CO ₂ in the US as of October, 2016
7. In-Salah: located in Algeria, started injection in 2004 at a rate of 1 – 1.2 Mt/y CO ₂ . Source: gas processing from In Salah Oil Fields. Storage: The Krechba Formation is a depleted gas reservoirs located near the gas processing plant. This formation is 1.9km thick Carboniferous sandstone unit at the Krechba field, using three long-reach horizontal injection wells to inject the CO ₂ into the down-dip aquifer leg of the gas reservoir. The project is estimated to cost US \$2.7 billion.
8. Snøhvit operating in Norway, North Sea. 0.7 Mt/y CO ₂
9. Gorgon: operating in Onshore Barrow Island, Australia. 3 Mt/y CO ₂
10. Jilin Oil Field EOR Demonstration Project in China: started EOR injection testing ten years ago and has reached one million tonnes of injected CO ₂ in 2016

Table 1: Major CCS projects that are now underway across the world.

These early examples of CCS deployment in value-added applications such as EOR or ECBM production can provide the necessary precedent, infrastructure, knowledge base, and experience for future large-scale deployment. The application of CCS is most dominant in the industrial sector, especially in sectors or processes that already 1) separate CO₂ in their normal business operations, such as natural gas processing and fertilizer production or 2) process gas streams with high enough CO₂ concentrations such that separation will be relatively inexpensive, such as hydrogen production. There is still vast potential for the application of CCS in large scale operations that are high CO₂ emitters such as blast furnace steelmaking and cement manufacture.

Mineral Carbonation

Atmospheric carbon can be transformed into carbonate minerals either in-situ or ex-situ. In-situ involves injection into geological formations, where elements needed for carbonate formation are present. The ex situ approach involves the aboveground carbonation of natural minerals and industrial alkaline wastes via industrial processes (IPCC, 2005). This includes a pre-treatment and sequestration process. The pre-treatment process precedes carbonation and involves mining, crushing and milling the mineral-bearing ores for the purpose of increasing the reactive surface available for carbonation. The ex situ mineral carbonation process can be divided into direct methods, where the mineral is carbonated in one step, and indirect methods, where the reactive components, such as Ca or Mg is extracted from the mineral matrix and carbonated in a later step. The resulting material of indirect mineral carbonation is a relatively pure carbonate.

Direct carbonation routes include:

1. Gas-solid route: reaction of gaseous CO₂ with solid mineral or alkaline waste, most straightforward but suffers from very slow reaction rates, and will not likely significantly reduce CO₂ emissions (Reddy *et al.*, 2008).
2. Aqueous carbonation: direct aqueous carbonation occurs in a single reactor with three coexistent mechanisms.

Mineral carbonation technology involves chemically reacting CO₂ with minerals containing sources of calcium (Ca²⁺), magnesium (Mg²⁺), or iron (Fe²⁺) cations to form stable carbonate materials such as calcite (CaCO₃), magnesite (MgCO₃) and siderite (FeCO₃) (Metz *et al.* 2005). Once in solid form, the carbon is for all practical purposes immobile; mineral carbonation is thus an attractive sequestration technology for the safe, permanent storage of CO₂ requiring little or no monitoring (Oelkers, Gislason, and Matter, 2008). This reaction occurs naturally through silicate weathering, in which naturally occurring silicates is a source of alkaline and alkaline-earth metals consumes atmospheric CO₂. Weathering of rocks to form carbonates takes place on a geological time scale, but CCS can emulate this natural chemical transformation while speeding up this reaction (Giammar, 2005).

Oxides and hydroxides of calcium and magnesium are the ideal materials for mineral carbonation but they rarely occur in nature. Instead, common sources of metal oxides are silicate minerals, such as olivine, serpentine, enstatite (MgSiO₃), talc (Mg₃Si₄O₁₀ (OH)₂) and wollastonite. The vast amount of magnesium silicate minerals that exist worldwide suggest that mineral carbonation is feasible on a large scale. The total mass of carbon currently in the atmosphere is approximately 800 Gigatons, and approximately 39,000,000 Gt of carbon are present in carbonate rocks, marble, limestone and chalk (Oelkers and Cole, 2008). The

proportion of terrestrial carbon bound in these minerals is 50,000 times more carbon than in the atmosphere. This suggests there is large potential for storing atmospheric CO₂ as carbonate minerals. Common magnesium silicates are olivine (Mg₂SiO₄), pyroxene (MgSiO₃), and serpentine (Mg₃Si₂O₅(OH)₄).

Rock Type		MgO wt%	CaO wt%	R _c	R _{CO₂}
Peridotites:	Dunites	49.5	0.3	6.8	1.8
	Harzburgite	45.4	0.7	7.3	2.0
	Lherzolite	28.1	7.3	10.1	2.7
Serpentinite		~40.0	~0.0	~8.4	~2.3
Gabbro		~10.0	~13.0	~17.0	~4.7
Basalt:	Tholeiite	6.2	9.4	26.0	7.1

Table 2: Abundant Rock Types Rich in Magnesium and Calcium. Adapted from IEAGHG (2000)

*R_c is the mass ratio of rock needed for CO₂ fixation to carbon burned

*R_{CO₂} is the corresponding mass ratio of rock to CO₂

Based on Table 2, peridotites and serpentinites appear to have the most potential for CO₂ sequestration because their mass ratios of rock to CO₂ are relatively low (R_{CO₂} between 1.8 and 2.7). However, serpentinites have lower densities and higher water contents, and therefore have much less Mg than peridotites. Using Table 2, sequestration of 3 Mt of CO₂ annually will require 5.4 to 8.1 Mt annually of peridotite and serpentinite. Sequestering the same amount of CO₂ will require 21 Mt of basalt rocks, assuming the sequestration process is taken to completion. Dolomite CaMg(CO₃)₂ is a potential feedstock that requires higher tonnages – approximately 15 Mt per year – compared to magnesium silicates.

Using rocks containing magnesium silicate are more efficient because magnesium silicate containing rocks have a higher MgO concentration, up to 50% by weight (with

theoretical CO₂ storage capacity of 0.55kg CO/kg rock), than calcium silicate containing rocks, which have CaO content of 10% by weight only (with theoretical CO₂ storage capacity of 0.08 kg CO/kg rock) (Goff and Lackner, 1998). Wollastonite is the most calcium-rich silicate (35% CaO by weight) (Lackner et al., 1995 ;Wu et al., 2001). However, rocks rich in magnesium silicates (xMgO·ySiO₂·zH₂O) are commonly favored in mineral carbonation because of their abundance. Magnesium silicates may be capable of binding all fossil-fuel sourced carbon (Lackner and Ziock, 2000). Table 3 shows the theoretical mass of rock needed per tonne of sequestered CO₂. The table also shows the corresponding ratios of Ca are greater due to the fact that the Ca atom is heavier than the Mg atom. (This table shows best case values, assuming that the rock is contains only the pure mineral with no waste of the mineral in conversion to the carbonate.)

Material	Mass (g) of 1 mole of material	Molar ratio of CO ₂ to rock	Mass (t) to sequester 1 t of CO ₂
CO ₂	44.0	-	-
Mg ₂ SiO ₄	140.7	0.5	1.6
MgSiO ₃	100.4	1.0	2.3
Ca ₂ SiO ₄	172.2	0.5	2.0
CaSiO ₃	116.2	1.0	2.7
Mg₃Si₂O₅(OH)₄	277.1	0.33	2.1
Mg(OH) ₂	58.3	1.0	1.3
Ca(OH) ₂	74.1	1.0	1.7
MgO	40.3	1.0	0.92
CaO	56.1	1.0	1.3

Table 3: Sequestering Properties of Various Chemical Phases. Adapted from IEAGHG (2000)

Using pure Mg₂SiO₄ source of Mg to sequester 3 Mt of CO₂ produced annually by a typical power plant would require approximately 5 Mt of minerals to be mined and converted to remove the annual emission of CO₂. The modern extractive industry is capable of procuring the amount of rocks required for mineral carbonation by a typical power plant (IEAGHG, 2000).

This still assumes the product used is in a pure form, while in reality, impurities and process inefficiencies will require greater tonnages to be mined than our simple calculation.

Sources of Silicate Minerals

Serpentine and olivine minerals are commonly found in ophiolite belts, which are geological regions of colliding plates leading to an uplifting of the earth's crust (Coleman, 1977). There are large peridotite masses located in major mountain fold belts and where fragments of mantle material have been caught up in crustal orogenesis (Hess, 1989). Well documented ophiolite belts in the US include the Cordilleran belt in the west coast and Appalachian belt (IEAGHG, 2000).

The large layered intrusion is the second class of ultramafic rock. These large magma bodies intruded into shallow levels of the crust and slowly cooled, allowing for fractional crystallization to cause early crystallizing Mg-rich silicates to settle by gravity to the base of the intrusion (IEAGHG, 2000). As a result, many of the larger intrusions contain peridotite layers several hundreds of meters thick. An example of a layered intrusion body in the US is in Stillwater, Montana.

Basalts would make an ideal feedstock because of its abundance and well-distributed supplies around the world. The Columbia/Snake River flood basal in North America, with an average thickness of about 1 km and estimated volume of 200,000 km³, could absorb all the CO₂ generated from the estimated world coal reserves 2.5 times over (Lackner et al, 1996). Outside the scope of the US, the Deccan traps in India is the world's largest outpouring of basaltic magma, which could be a promising source of feedstock (IEAGHG, 2000).

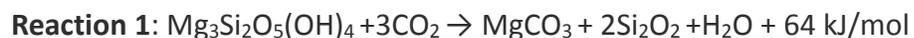
Sources of silicate material is examined to determine to economic feasibility of transporting the feedstock to existing power plants. Ideally, a major power plant will be adjacent to a plentiful source of feedstock for CCS in order to minimize transportation costs, while also taking into account proximity to the sequestration plant. Since basalt and dolomite are the most geographically widespread, they provide the most accessible feedstock option for power plants. Dolomite is often associated with other carbonate rocks, such as limestones, which are often adjacent to coal supplies (IEAGHG, 2000). Historically, coal fired power plants are in close proximity to coal supplies, therefore dolomite will likely be a favorable option for existing coal fired power plants.

An alternative source for mineral carbonation is from industrial alkaline wastes, which supplies the calcium and magnesium necessary to convert CO₂ into carbonates. The benefits for sourcing from industrial alkaline wastes include low cost, high reactivity compared to that of natural minerals, and potential of removing potentially-toxic elements and improving environmental quality (Meima et al., 2002). Limitations of using industrial waste is that they exist in smaller quantities than natural minerals.

Examples of Carbonation Reaction



(MO is a metal oxide, M is a divalent metal e.g. calcium, magnesium, iron).



The transformation of the common silicate mineral serpentine, Mg₃Si₂O₅(OH)₄, and CO₂ into magnesite, MgCO₃, silica and water. Using this ideal case, 1 ton of serpentine can dispose of approximately one-half ton of CO₂.

Reaction 2: $\text{Mg}_2\text{SiO}_4(\text{OH})_4 + 2\text{CO}_2 \rightarrow 2\text{MgCO}_3 + \text{SiO}_2 + 90 \text{ kJ/mol}$

The transformation of forsterite, which is the end member of the common silicate mineral olivine. One ton of olivine can dispose approximately two-thirds of a ton of CO_2 . Again, the reaction is exothermic and releases 90 kJ/mol of CO_2 .

Reaction 3: $\text{Ca}(\text{SiO}_3) + \text{CO}_2 \rightarrow \text{CaCO}_3 + \text{SiO}_2 + 90 \text{ kJ/mol}$

The transformation of wollastonite into calcite and silica.

The interaction of CO_2 with silicates phases (forsterite, serpentine) energetically favor formation of carbonate phases (Seifritz, 1990; Lackner *et al.*, 1995; Lackner, 2002). These reactions have been observed in nature and in the laboratory (McGrail *et al.*, 2006). The amount of heat will depend on the specific metal and material containing the metal oxide (Robie *et al.*, 1978). The formation of carbonates is thermodynamically favored at low temperature because the reaction releases heat. At high temperature (above 900 above 900 °C for calcium carbonate and above 300 °C for magnesium carbonate, at a CO_2 partial pressure of one bar) the reverse reaction (calcination) is favored (Olajire, 2015). Carbonation of metal oxide bearing minerals is spontaneous even at low partial pressure of atmospheric CO_2 and at ambient temperature, but on geological time scale (Lasaga and Berner, 1998).

Challenges of Mineral Carbonation

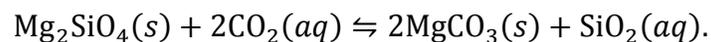
Much effort is dedicated to improving the kinetics of silicate dissolution, which is the rate-limiting step. Operating conditions such as CO_2 concentration, temperature, pressure, solid to liquid ratio, and particle size can be varied, as well as using a wide range of additives (O'Connor *et al.*, 2004a, 2004b). The dissolution of serpentine, $\text{Mg}_3\text{Si}_2\text{O}_5(\text{OH})_4$ occurs rapidly at

first and dissolution slows down in the later phase (Carey et al., 2003). Enhancing mineral CO₂ sequestration will need to focus on the second, slow phase.

Another challenge for mineral carbonation is overcoming the formation of silica or carbonate layers on the mineral surface during carbonation that prohibit further reaction and limit conversion (Butt et al., 1996). Mineral carbonation can be improved by accelerating carbonation and exploiting the heat of the reaction within the environmental constraints. Further study on the dissolution of Ca/Mg from the solid silicate particles is necessary to improve aqueous carbonation scheme, especially on dissolution kinetics at elevated temperature and CO₂ pressure, increase of specific surface area, lowering the (Ca/Mg)²⁺ activity in solution, and removal of the SiO₂ layer.

Reproduction of Reaction Kinetics

From 2011 to 2016, scientists in the Department of Geology & Geophysics at Yale University carried out laboratory experiments with olivine minerals to understand the rates and outcomes of mineral carbonation reactions. The research project was sponsored by the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy, as part of its CO₂ Capture R&D Program (Vora, 2013). The Yale experiments explored the kinetics of reacting sodium bicarbonate (NaHCO₃) solution with magnesium-rich olivine (Mg_{2-x}Fe_xSiO₄), at high temperature and pressure, to form carbonate minerals, such as magnesite (MgCO₃) and siderite (FeCO₃). For example, with pure forsterite (Mg₂SiO₄), the net mineral carbonation reaction is



The study found that, when the reaction was left to run for more than about 72 hours (3 days), magnesium-bearing silicate minerals other than Mg₂SiO₄ were present in the reaction products,

in addition to magnesite (Wang et al., 2015). The presence of these secondary silicates appeared to coincide with a reversal of the main mineral carbonation reaction, evidenced by the amount of magnesite reaching a peak and then decreasing over time. Figure 3 shows a typical result. In this run, the carbonation fraction—a measure of how much magnesite has formed from olivine with respect to time—rises to about 52% after 3 days of reaction time, then declines to about 44% after 14 days.

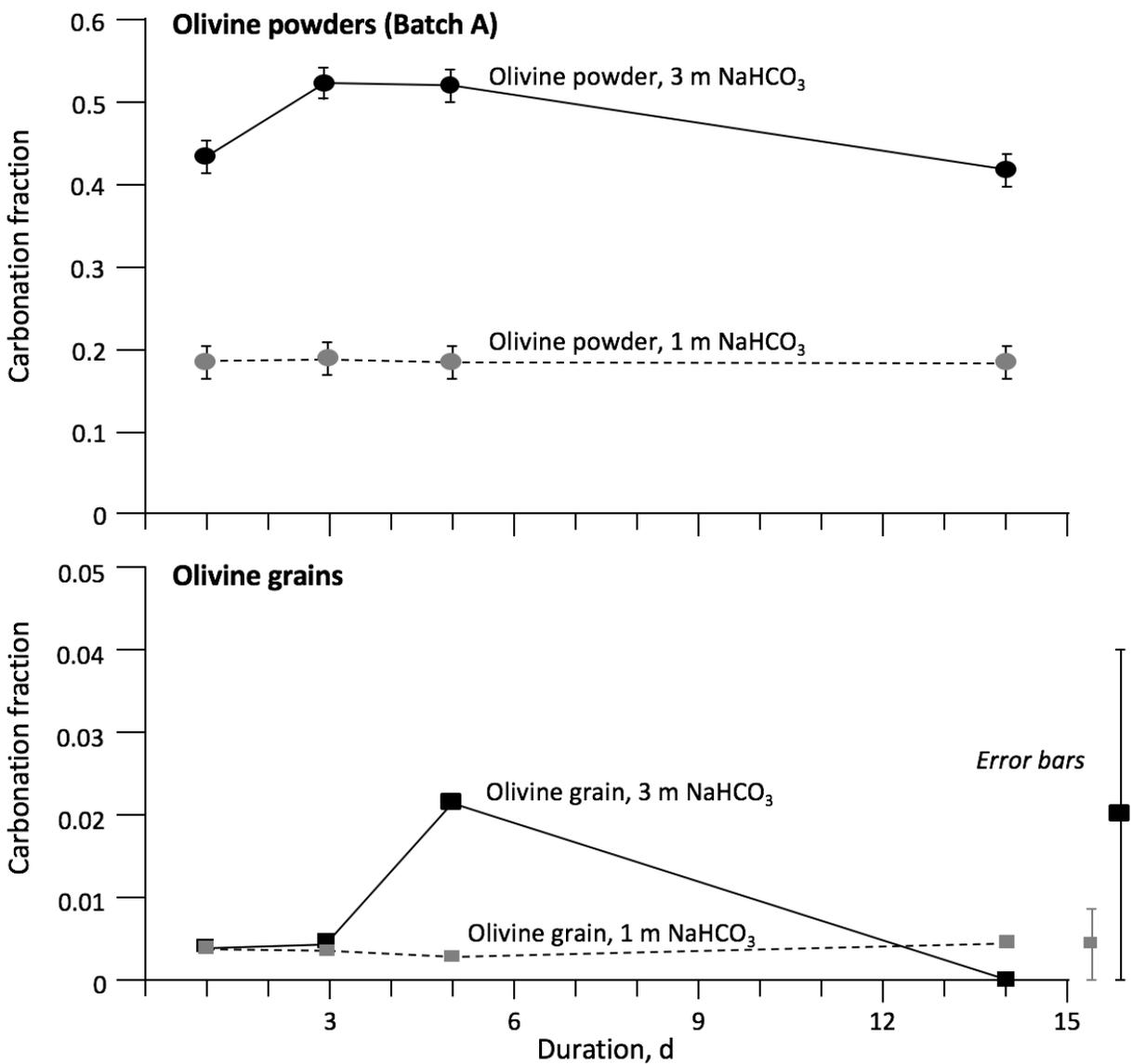
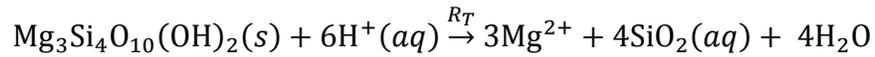
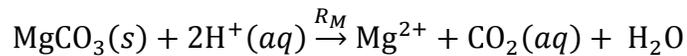
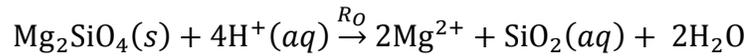


Figure 3: Carbonation fraction – a measure of how much magnesite forms from olivine

The goal of this part of the research for my thesis was to try to understand these experimental results with simulations of the reaction kinetics in a simple model that includes competition between olivine dissolution, formation of magnesite, and formation of the magnesium-bearing silicate talc ($\text{Mg}_3\text{Si}_4\text{O}_{10}(\text{OH})_2$). Results from reaction models, like the one studied in this research, could point to the factors contributing to reversal of olivine carbonation and suggest ways of increasing the carbonation efficiency.

Reaction Model

The reactions modeled were the following set:



With reactions going to the right, as written, these equations represent the dissolution, respectively, of olivine, magnesite, and talc minerals exposed to an acidic aqueous (*aq*) solution. Going to the left, the equations represent precipitation of the respective minerals from species in solution. The quantities, R_O , R_M , and R_T are the rates for each reaction in mole per second (mol/s): a positive reaction rate thus corresponds to dissolution; a negative rate, to precipitation.

The reaction equations give the following set of coupled ordinary differential equations for the amounts (concentrations) of the species in solution,

$$\frac{d}{dt}m_{\text{Mg}^{2+}} = 2R_O + R_M + 3R_T$$

$$\frac{d}{dt}m_{\text{H}^+} = -4R_O - 2R_M - 6R_T$$

$$\frac{d}{dt}m_{\text{SiO}_2} = R_O + 4R_T$$

$$\frac{d}{dt}m_{\text{CO}_2} = R_M$$

In general, the reaction rates will be complicated functions of the species' concentrations, expressed through activity coefficients, and other experimental conditions, such as temperature, pressure, available reactive surface area, etc. For the purposes of this study, we will assume an idealized model in which the reaction rates are driven only by the concentrations of aqueous species according to the following form,

$$R_I = k_I \left(1 - \frac{Q_I}{K_I} \right),$$

where k_I and K_I are reaction-rate and equilibrium constants for reaction I , and the quantity Q_I has the form,

$$Q_I = \prod_J m^{\gamma_{IJ}}$$

Here, γ_{IJ} is the stoichiometric coefficient of species J in reaction I , and is positive or negative according to its presence, respectively, on the right- or left-hand side of the reaction. For example, we have

$$R_O = k_O \left(1 - \frac{m_{\text{Mg}^{2+}}^2 m_{\text{SiO}_2} m_{\text{H}^+}^{-4}}{K_O} \right)$$

$$R_M = k_M \left(1 - \frac{m_{\text{Mg}^{2+}} m_{\text{CO}_2} m_{\text{H}^+}^{-2}}{K_M} \right)$$

$$R_T = k_T \left(1 - \frac{m_{\text{Mg}^{2+}}^3 m_{\text{SiO}_2}^4 m_{\text{H}^+}^{-6}}{K_T} \right)$$

In all cases, it is assumed that the concentration (activity) of water is effectively 1 throughout.

Limitations of the model

The model studied here has limitations that I want to briefly address before presenting the results of my calculations. The first and most important is the use of the raw (molar) concentrations of the ionic species as the driving force in the reaction model. In chemical thermodynamics, it is *activity*—a measure of the “effective concentration” of a species in solution—that determines a reactant’s chemical potential, which in turn controls its role in a chemical reaction. Concentrations can be related to activity using activity coefficients, but activity coefficient can be complicated functions not only of the reactant’s concentrations, but of the concentrations of all the other reactants and species in solution, as well as function of experimental variables such as pressure, temperature and available reactive surface area.

The model studied here assumes that all activity coefficient are equal to 1, and that the reaction rates are therefore driven only by the concentrations of the aqueous species. This approximation would apply in a system with a large enough volume such that the reactants can fully disperse throughout the volume. The purpose of the simulations was not, however, to reproduce all the conditions of the experiment, but rather to explore a simple, transparent model that might help illuminate the dynamics of mineral carbonation.

Numerical Methods

The simulations in this work used MATLAB to solve the coupled set of nonlinear ordinary differential equations, described in the previous section, to obtain the species concentrations as a function of time. MATLAB provides the function `ode45` for this purpose:

`ode45`: Solve nonstiff differential equations — medium order method

Syntax

```
[t,y] = ode45(odefun,tspan,y0)
```

```
[t,y] = ode45(odefun,tspan,y0,options)
```

```
[t,y,te,ye,ie] = ode45(odefun,tspan,y0,options)
```

```
sol = ode45(____)
```

`[t,y] = ode45(odefun,tspan,y0)`, where `tspan = [t0 tf]`, integrates the system of differential equations $y'=f(t,y)$ from `t0` to `tf` with initial conditions `y0`. Each row in the solution array `y` corresponds to a value returned in column vector `t`.

Figure 4 shows the results of a sample calculation, using the following parameters shown on the top right of the figure.

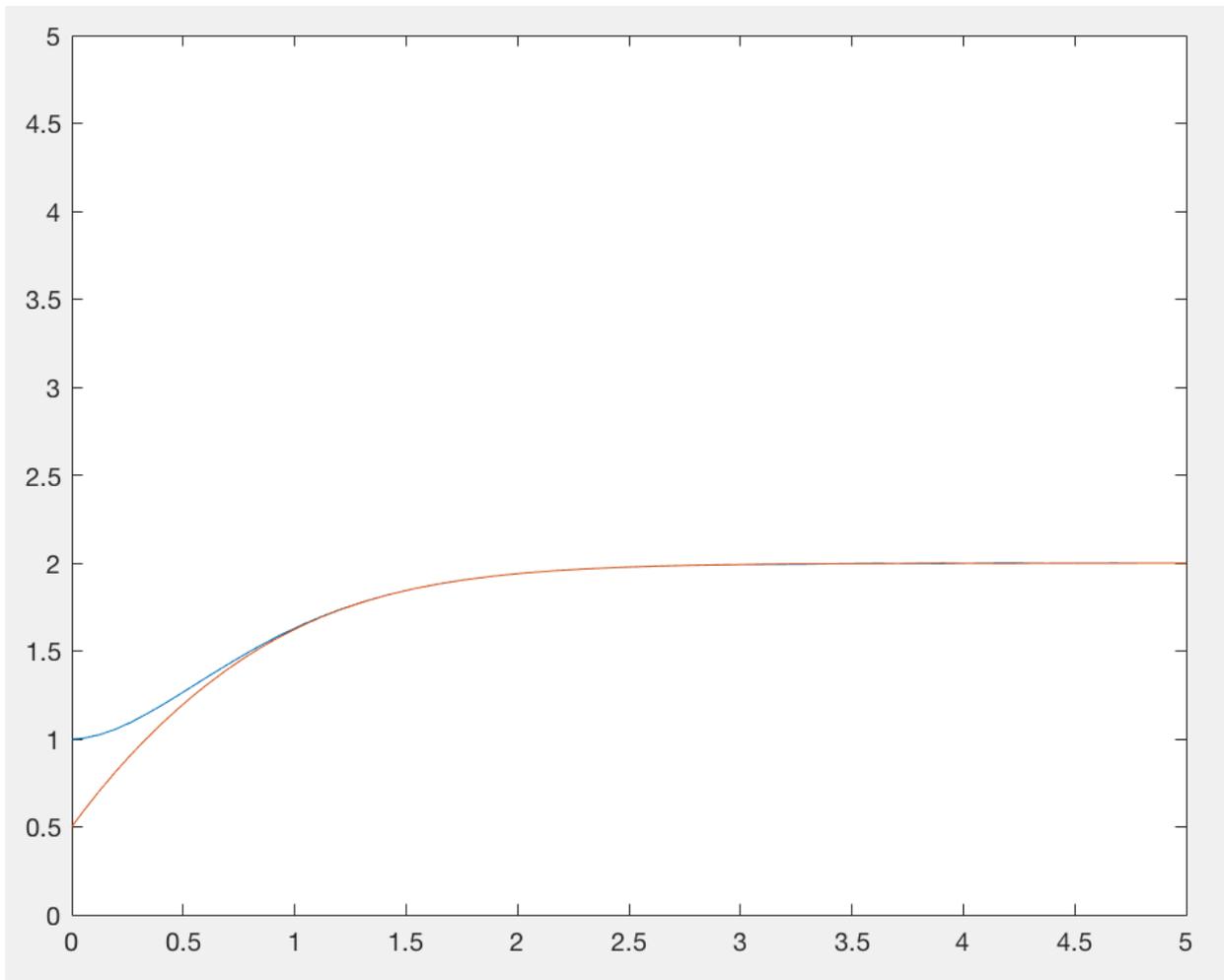


Figure 4

Obtaining the mineral amounts

After solving for the concentrations of the species, we use the reaction rates for three reactions to determine the amounts the minerals—olivine, magnesite or talc—that are present, by tracking whether the minerals are precipitating or dissolving in solution. We use the relations

$$S_{(O,M,T)}(t) = S_{(O,M,T)}(0) + \int_0^t R_{(O,M,T)}(t') dt',$$

where $S_{(O,M,T)}$ is the amount (in moles) of either olivine, magnesite or talc present, $S_{(O,M,T)}(0)$ is the corresponding starting amount and $R_{(O,M,T)}(t)$ is the corresponding reaction rate as a function of time. The reaction rates can be obtained from the species' concentrations using the equations in the previous section.

The function `ode45` returns the concentrations of the species at different times in a numerical matrix, whose columns, in this case, correspond to the different species in the reactions, and whose rows correspond to outputs at different times. The collection of output times is determined by the function to give an accurate solution to the ODEs, and are returned in a numerical vector. We use these outputs and the MATLAB functions, `diff` and `cumsum`, to do a simple integration of the equations above. For example, let `RO` be a numerical vector with the reaction rates for the olivine dissolution reaction as a function of the times in the numerical vector `T`. The function `diff` applied to `T` (`diff(T)`) gives a new vector whose entries are the differences between successive rows of `T`—i.e., the time increments. We multiply these increments row by row by the reaction rates in the vector `RO`, and take the cumulative sum of the resulting vector to approximate the integral and add the starting amount of olivine to give the variation in the amount of olivine over time. More sophisticated integration methods can be used, but I found that this simple method gives smooth results for the calculations in these simulations. The top panel of Figure XX shows the results of applying this algorithm to the species concentrations in the lower panel.

Simulations

To test the reaction model against the experimental results, we ran the model for a wide range of k , K , Q , initial and final T values. The results are shown in Figure 5 for the set of parameters displayed in Table 4. As explained in the previous section, these curves plotted show the amount of each mineral (olivine, magnesite, and talc) as a function of time. Figure 5 shows the dissolution of olivine, formation of magnesite, dissolution and precipitation of talc. In all cases, the reaction rates approach zero at day 6.

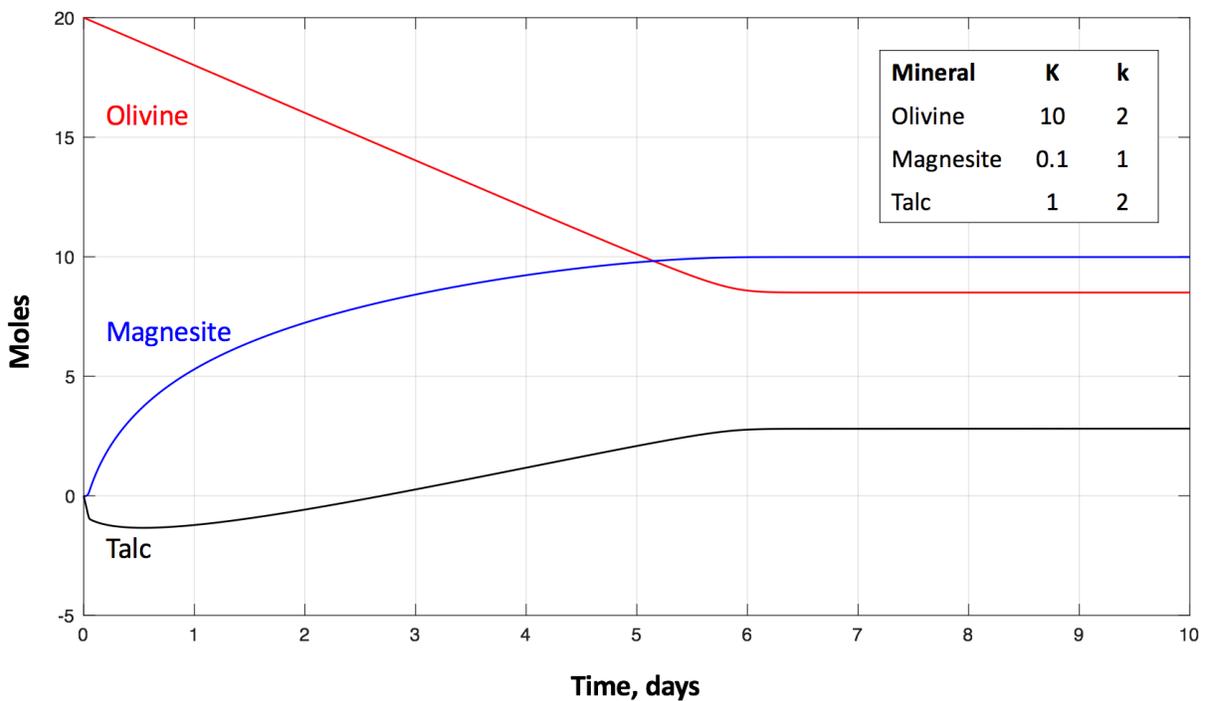


Figure 5

Simulations in which the equilibrium constants and reaction constants were varied by 2 orders of magnitude about the parameters in Table 4. Figure 6 shows the 729 runs superimposed on the plot. The red curves plot amount of olivine, blue curves plot the amount of magnesite, and black curves plot the amount of talc as a function of life. In all cases, the

coupled reactions saturate and the carbonation fraction plateaus, but does not decrease over time.

Mineral	K	k
Olivine	10	2
Magnesite	0.1	1
Talc	1	2

Table 4

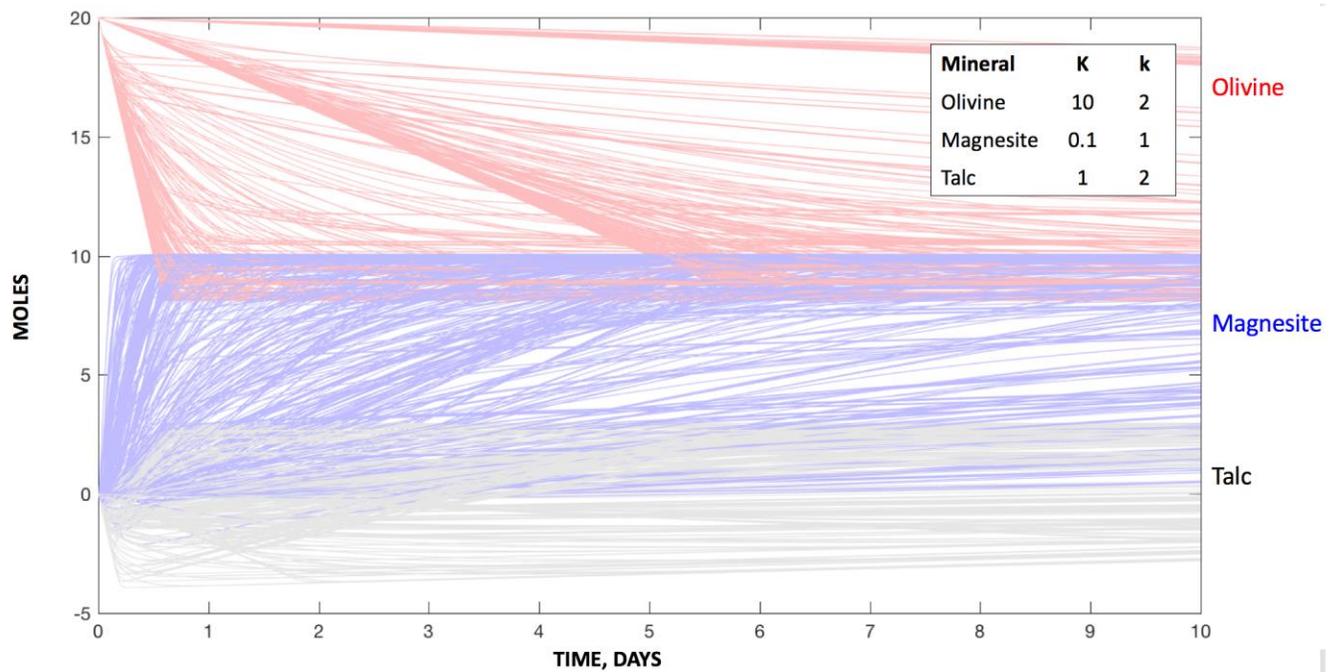


Figure 6: Simulation with K and k varied by 2 orders of magnitude

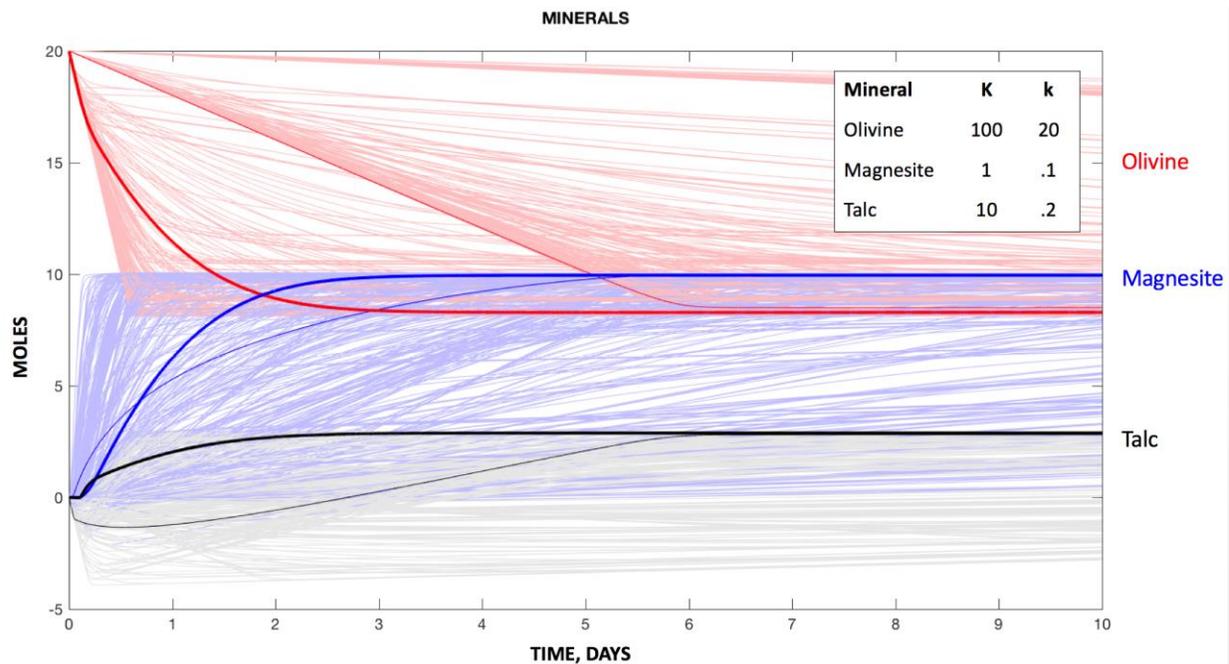


Figure 7: Simulation with a set of parameter values that better matches the initial pattern of carbonation

Figure 7 shows simulation results for a set of parameter values that better matches the initial pattern of carbonation because the curve for talc remains positive for all values of time. Olivine dissolves and magnesite forms, then plateaus, which is similarly shown in Figure 6. There was no combination of parameters for which the evolution of the amounts of the minerals over time matches the pattern of the experimental results. Instead, the model always shows a steady trend in which olivine continues to dissolve, while magnesite and talc continue to form until the reaction stabilizes.

Although not exhaustive, these results suggest that the simple kinetic model involving competition between olivine dissolution and magnesite and talc formation does not explain the main experimental result of the Yale mineral carbonation project. There appear to be other, more complex reactions happening in the reaction cell when the reaction is run for many days. These reactions could involve the precipitation of other magnesium-bearing silicates such as

chrysotile and antigorite (Qiu et al., 2016) and interactions between the ionic species in solution that change their activities.

Other possibility is a physical “armoring” effect. For example, as olivine dissolves and magnesite forms, the magnesite coats the surface of the olivine minerals (Figure 8). The magnesite growing on the surface of the olivine decreases the surface area exposed to the solution, thus slowing down the dissolution of olivine. Once the dissolution of olivine terminates, the production of additional magnesium ions also stops, thus eliminating the supply of magnesium ions in solution to produce magnesite and talc. Conditions could then arise under which it is favorable to dissolve some of the magnesite coating the olivine crystals to form additional talc.

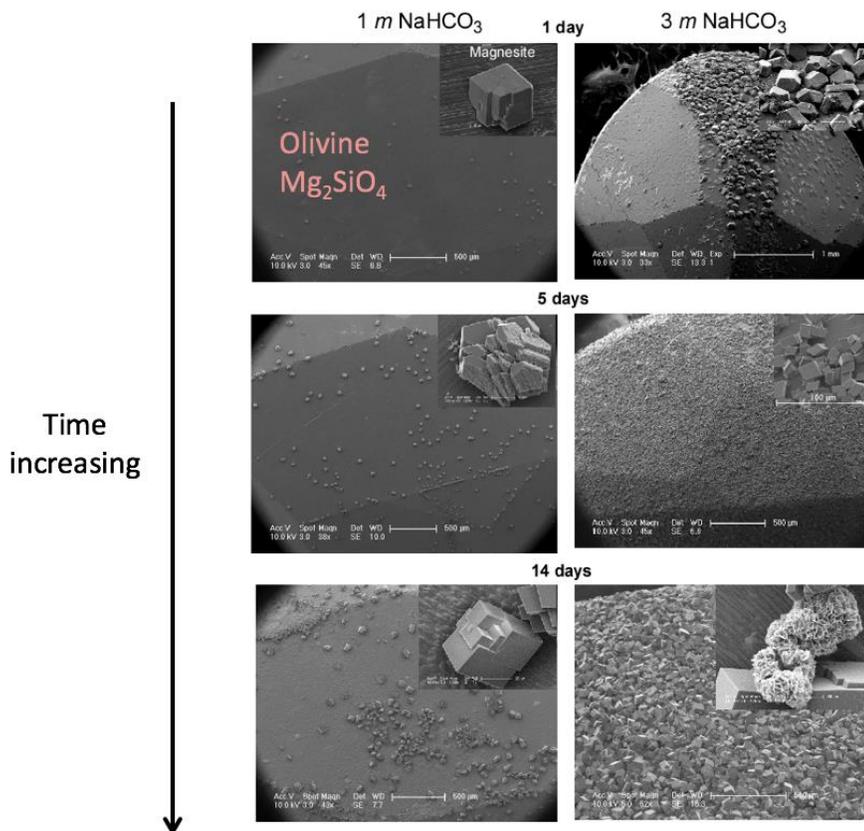


Figure 8: Formation of magnesite on olivine crystals, possible formation of secondary minerals magnesium silicates

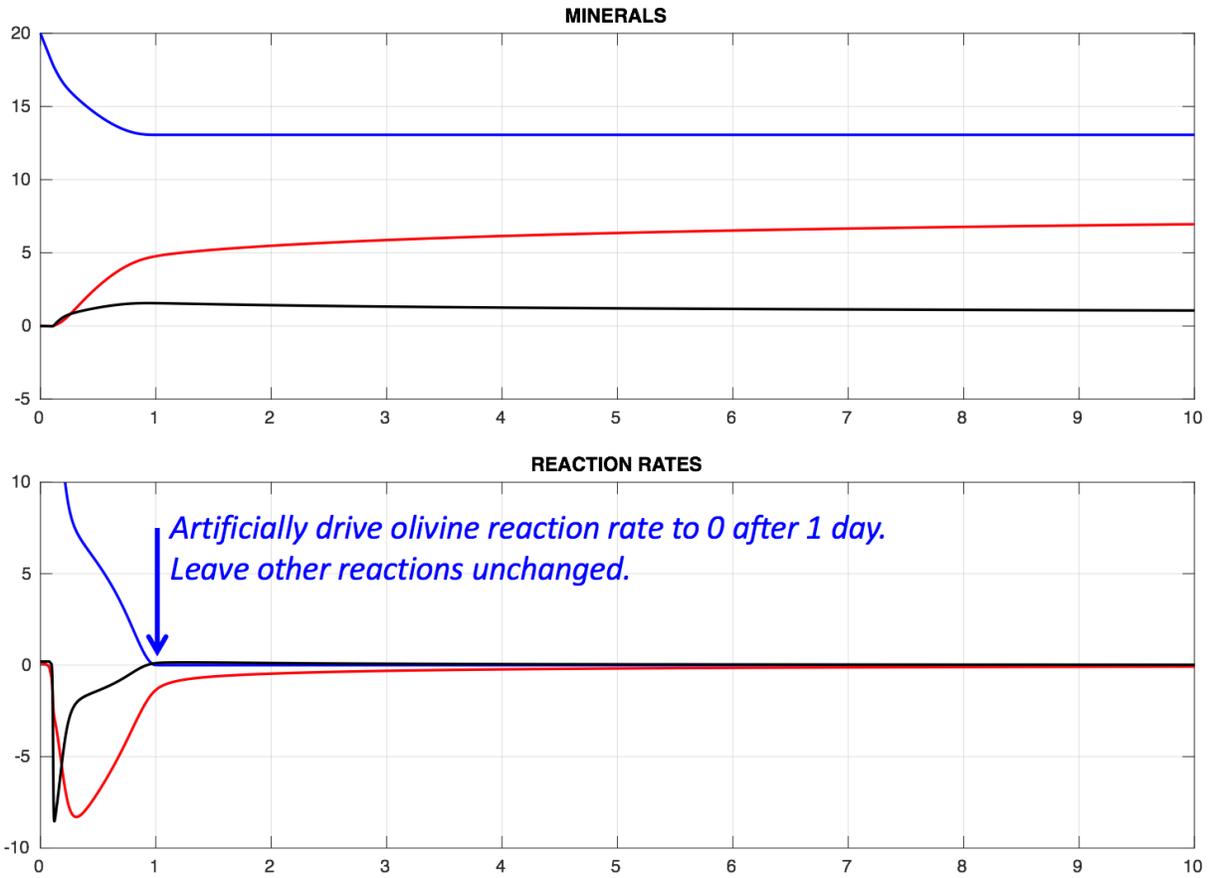


Figure 9

Figure 9 shows a simple model that shuts off olivine dissolution (e.g. by armoring) by driving the olivine reaction rate to zero after one day. Figure 10 shows the result of shutting off olivine dissolution. The talc peaks and dissolves, but not the magnesite does not.

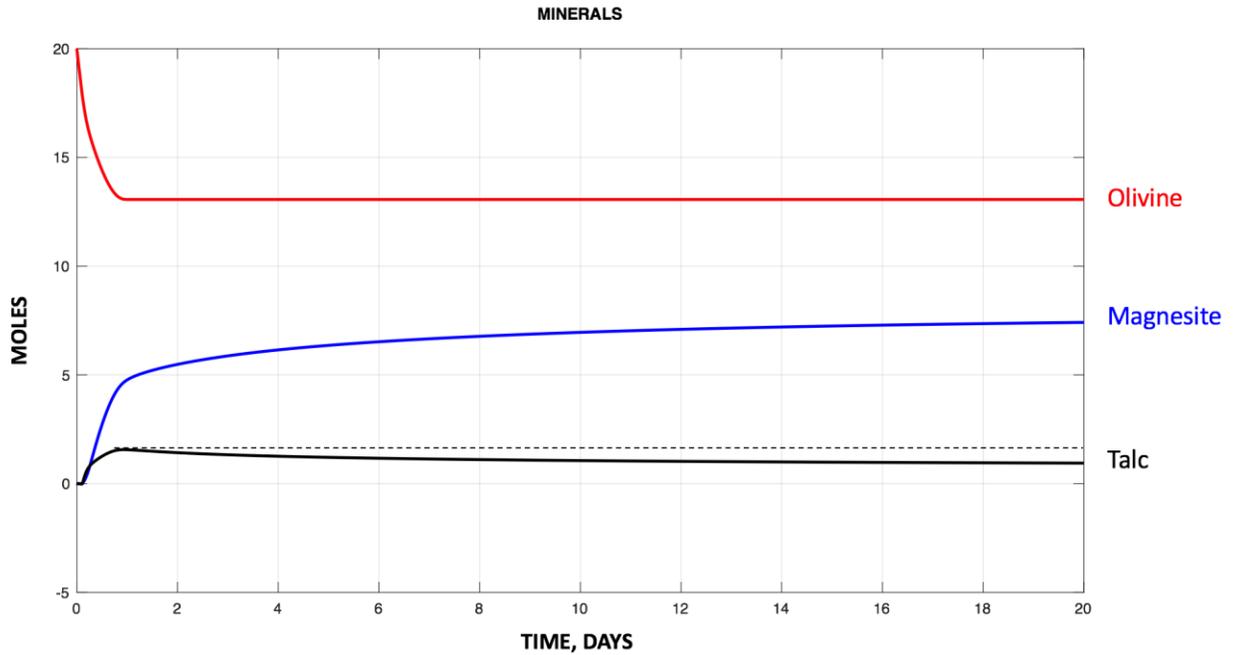


Figure 10

Since this study assumes an idealized model in which the reaction rates are driven only by the concentrations of aqueous species, it does not account for other experimental conditions that could have influenced the chemical reactions. These experimental conditions include pressure, temperature, surface area exposed to solution, and presence of acid and base. The dissolution rates of olivine are sped by increasing temperature, by increasing the water–mineral interface area, and by adding acid or base (Oelkers, 2001; Carroll and Knauss, 2005). Huijgen et al suggest increasing temperature and grinding the silicate source materials and dissolving them in acidic solutions could optimize mineral carbonation (Huijgen et al., 2006).

Carbon Capture at Yale Central and Sterling Power Plant

There is much effort worldwide in developing improved and lower-cost technologies (NCC, 2015) in order to inform policymakers about the costs and benefits of CCS in future energy systems. Yale is an institution among many other organizations involved in energy-related decision making that can benefit from better understanding the role of CCS and the costs associated with implementing the technology. This section examines the feasibility and cost of implementing capture and storage of CO₂ emissions from the Yale power plants that provide electricity, heating and cooling to the Yale University main campus. The cost analysis considers the energy output by Yale's power plants in 2016 to determine the costs associated with capturing the CO₂ from the flue gas, compressing it to a supercritical fluid, transporting the fluid to a storage site, and injecting it into an underground geologic formation.

Demonstration projects have shown that CCS is suitable for stationary fossil fuel power plants (IPCC, 2005). The Yale power plants are examples of natural gas combined cycle, stationary fossil fuel plants that are possible candidates for applying CCS. This paper will focus on the post-combustion capture process using amine capture at the Yale power plants, rather than pre-combustion capture. Post-combustion capture retrofit will be expensive and technically challenging, compared to applying CCS to a new power plant, which can be optimized through energy efficiency and minimization of transportation costs with a secure disposal reservoir in close proximity. Although the overcoming the challenges associated with retrofitting the existing natural gas combined cycle power plant will be expensive and difficult, there are environmental and social arguments for applying CCS to Yale's power plants.

Why implement CCS at Yale?

Yale strives to be a leader in climate action. In the Yale Sustainability Plan, Peter Salovey stated that “As a higher education institution with a global presence, Yale is committed to sustainability planning and actions that forge new paths.” CCS is a great opportunity for a higher education institution like Yale to demonstrate its commitment to innovative sustainability planning and action to the world.

Yale delivers a sustainability plan every three years to lay out its vision of a more sustainable campus and future. The Yale Sustainability Plan 2025 defines nine ambitious goals to integrate sustainability into the scholarship and operations of the university (Figure 1). Among the nine sustainability goals, three best call for the need of employing CCS technology at Yale: 1) Technology: Explore innovative technological platforms to address sustainability challenges, 2) Leadership: Demonstrate local and global leadership in sustainability teaching, research, service, and operations, 3) Climate Action: Take urgent action to mitigate climate change and proactively adapt to its impact. Unifying these three goals together, Yale should strive to implement CCS at its own facility as a research opportunity to demonstrate the feasibility of CCS technologies in addressing sustainability challenges and position itself as an academic and sustainability leader focused on achieving social and environmental excellence by taking urgent action to mitigate climate change.

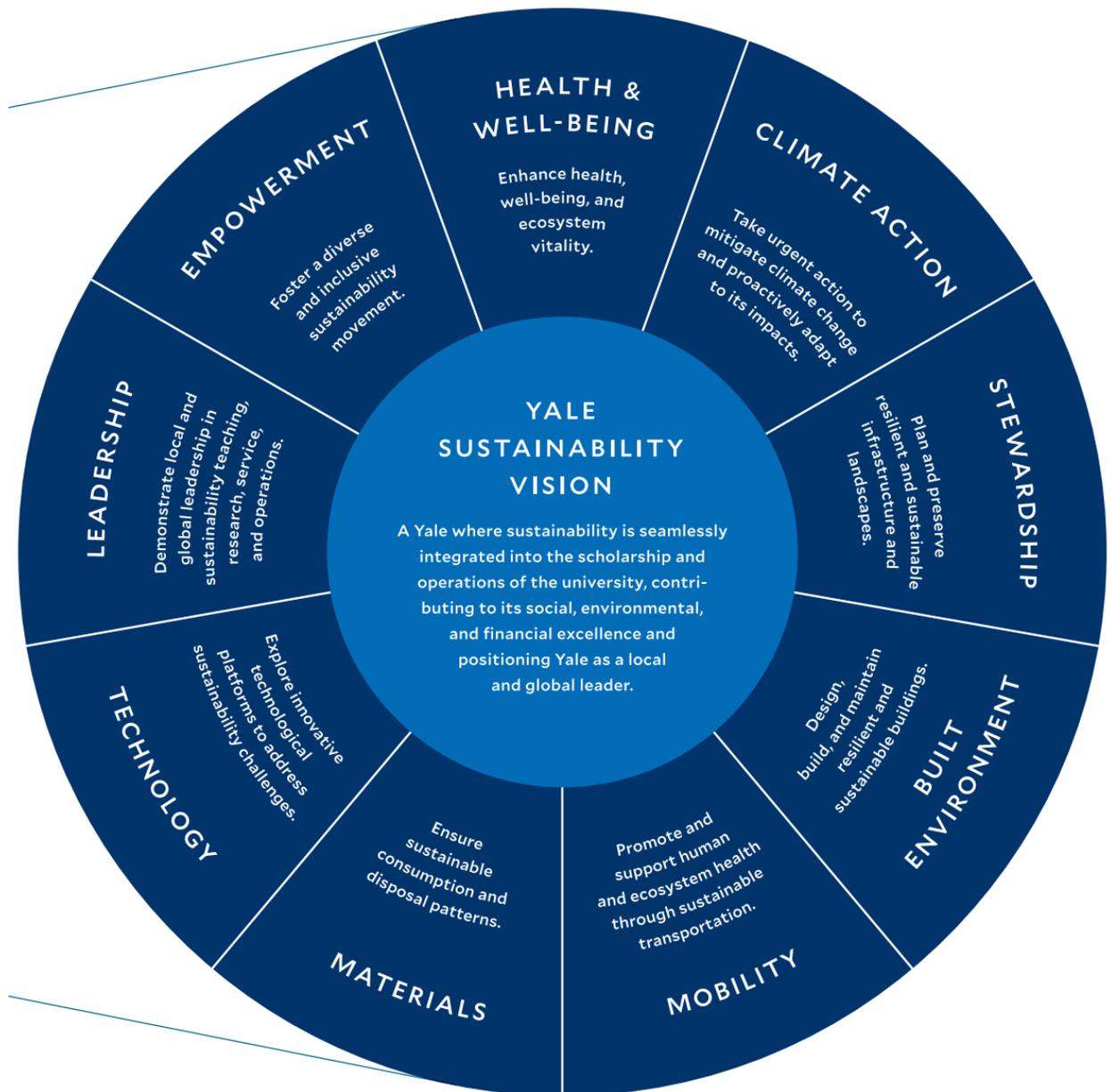


Figure 11: The Yale Sustainability Plan 2025 nine ambitious goals

Yale has a sustainability goal of being carbon neutral by 2050 (YaleNews, 3 October 2016). The CO₂ emissions from the two Yale power plants make up most of the university's

direct carbon emissions. Capturing the CO₂ directly from these plants, if feasible, would be the fastest way for Yale to become carbon neutral.

CCS will be a relatively expensive technology. In general, dealing with climate change comes at a relatively high price. However, Yale's inaction – waiting for the cost of abatement to drop and hoping that a new low-cost technology instead of stepping up – goes against the tenets of its Sustainability Plan and Yale's mission of being “committed to improving the world today and for future generations through outstanding research and scholarship, education, preservation, and practice.” CCS is a relatively expensive technology, but there is also a fundamental difference between the price and value of something – the benefits to society as a whole may be greater than cost of the mitigation strategy.

Yale's Two Power Plant Facilities

CCS would be employed at the two power plants that generate energy for Yale's main campus, Yale School of Medicine and Yale-New Haven Hospital. The two power plants are Central Power Plant (CPP) and Sterling Power Plant (SPP). In addition to electricity generation by the two power plants, Yale purchases electricity from the Connecticut United Illuminating Company. The purchased electricity comprises 17% of Yale's total energy consumption.

Central Power Plant (CPP)

The Central Power Plant has been supplying energy to Yale's campus since 1918. The plant has transitioned its primary energy source from coal to natural gas. The plant is a co-generation facility that provides electricity, steam heating, and chilled water to Yale's main campus and Science Hill. The Central Power Plant has three 6.1 megawatt gas turbines and

three 1.5 megawatt peaking and emergency diesel generators with the total capacity of producing 18 megawatts of electricity and 340,000 pounds per hour of steam for heating.

Sterling Power Plant (SPP)

The Sterling Power Plant supplies the Yale School of Medicine and Yale-New Haven Hospital with electricity, steam, and chilled water. Sterling Power Plant was recently converted to a 15 Megawatt co-generation facility in 2010. It generates up to 15 megawatts of electricity from two turbines, and recycles the heat from electricity generation to help produce 180,000 pounds of steam per hour from two Heat Recovery Steam Generators.

	Nat Gas (MMBTU)	#2 Oil (MMBTU)	Purchased Elec (MMBTU)	MMBTU
SPP	1,685,560	42,565	89,422	1,817,546
CPP	992,823	41,085	403,850	1,437,759
Sub Tot	2,678,383	83,650	549,236	3,311,270

Table 5: Yale Central and Sterling Power Plant Energy Consumption

Emission Category	Inventory Year	Emission Source	Scope	UOM	CO ₂
Stationary Combustion	All	Fuel Oil #2	1	kg CO ₂ e / MWh	252.38
Stationary Combustion	All	Natural Gas	1	kg CO ₂ e / MWh	181.06

Table 6: Yale Emissions Factors

1 kilowatthour = 3,412 Btu	1 MWh = 3412000 Btu
1 MMBtu = 1000000 Btu	1 MWh = 3.412 MMBtu
1MWh = 1000 kWh	1 MMBtu = 1/3.412 MWh

Table 7: Unit conversion factors

Source:

https://www.eia.gov/energyexplained/index.cfm?page=about_energy_conversion_calculator

Costs of Carbon Capture

In this section, I estimate the costs of implementing carbon capture at the two Yale power plants in two different ways, using data from different sources. The first method uses cost estimates for retrofitting existing plants with amine capture technology; the second uses estimates of the total plant costs with retrofit of post-combustion capture. I estimate the costs for compression, transportation, storage at Mt. Simon Sandstone Formation, storage monitoring, and additional fuel load associated with running the capture technology at the power plants.

In a paper presented at the *IODP/ICDP Workshop on Geological Carbon Capture & Storage in Mafic and Ultramafic Rocks* (Oman, January 2011), Richard Darton, Co-Director of the Oxford Geoengineering Programme, estimated that retrofitting post-combustion carbon capture with standard amine technology in a modern power plant to remove 1 million tonnes per year CO₂ from its flue gas (at an 86% capture rate) would cost around US\$ 96 million (2009 prices installed). The cost calculations assume two absorbers, each 11 meters in diameter and 20 meters tall. The design is largely determined by the volume of gas treated and the percent capture.

Absorbers	26.0
L/R Heat Exchangers	18.3
Reboilers	14.5
Regenerators	9.6
Feed Cooler	8.7
Flue Gas Blowers	8.7

Pumps	7.7
Other	2.9
Total \$US mill	<u>96.4</u>

Table 8: Amine treating: Design and Costs – Capital. (adapted from Darton, 2011)

Assuming that a retrofit for a post-combustion plant removing 1 million tonnes of CO₂ per year from flue gas will cost US\$ 96 million, the cost for retrofitting Yale’s power plants can be approximated by scaling down the 1 million tons of CO₂ per year to Yale’s CO₂ emissions. This assumption can be made because a smaller power plant would have proportionally fewer number of components needed for amine treating. Additionally, the final calculations show that to Yale’s CO₂ emissions are approximately 1/6 of 1 million tonnes of CO₂, which is less than one full order of magnitude.

Conversions	MMBtu to MWh	MWh to kg CO2	kg CO2 to tonnes CO2
Fuel Oil #2	24,516	6187452	6187
Natural Gas	784,989	142130136	142,130
Total			148,318

Table 9

The CO₂ emission was calculated based on the energy output by the Central and Sterling power plants. The energy output and conversion factors were provided by Julie Paquette, the Director of Energy Management within the Office of Facilities. The energy output in MMBtu was converted to MWh and to kg of CO₂ (the UOM provided kg CO₂e / MWh), and finally to tons of CO₂ emitted for 2016. The conversion between MMBtu to tonnes of CO₂ was performed for both fuel oil #2 and natural gas. The total tonnes of CO₂ for both fuel oil #2 and natural gas amounted to 148,318 tonnes of CO₂. A post-combustion plant removing 1 million tonnes of CO₂

per year scaled down to a plant removing 148,318 tonnes of CO₂ for 2016 will cost approximately \$14.24 million.

Discussion

Table 9 shows that Yale's two plants emitted about 150,000 tons of CO₂ in 2016. The figures for the previous two years are 210,000 tons (2015) and 240,000 tons (2014) of CO₂, which are significantly greater than emissions for 2016. This is because CPP was partially offline in 2016. Considering that the emissions for 2014 and 2015 may be more representative of Yale's average emissions, we use a more realistic figure of 250,000 tonnes of CO₂ emissions in determining capture costs. This will also account for some overcapacity. Using Darton's estimates for amine technology scaled by an output of 250,000 tonnes of CO₂, the cost of capture is approximately US\$ 24.1 million.

The approximated cost of \$14.24 million is also likely an underestimate of the cost of retrofitting Central and Sterling power plant due to economies of scale. With larger power plants, there's a cost advantage that arises with greater amounts of CO₂ treated. A plant removing 1 million tons of CO₂, compared to a plant removing 148,318 tonnes of CO₂ can likely reduce variable costs per unit because of operational efficiencies and synergies. In a study on the economies of scale in power generation, Helden & Muysken (1981) suggest that economies of scale are partly determined by fuel input, e.g. large electricity generating units have a greater fuel efficiency than small ones, and that the scale effects in fuel efficiency are only present for units below 200 MW.

Cost of Membrane Separation

As described in a previous section, a second technology for CO₂ capture is through membrane CO₂ separation. Voleno et al. (2014) performed an economic analysis of the membrane technology to a reference NGCC plant. The study calculated a COE for the reference NGCC to be \$41.0/MWh, assuming 4 US\$/GJ and 58.4% plant efficiency, and found that COE for plants with CO₂ capture increased by approximately 22 \$/MWh to 40 \$/MWh.

Figure 12 shows that COE increases with higher feed pressure. Larger compressors and expanders are required for higher feed pressure. Figure 12 show the effects of the membrane feed pressure on costs for the membrane, flue gas compressor and expander. Both figures show the increase in capital cost with the addition of flue gas compressor and expanders, and suggest the membrane case that minimizes the cost of electricity is at 1.5 bar feed pressure, where COE is 63.8 \$/MWh (Voleno et al., 2014). If the CPP & SPP employed membrane CO₂ separation technology with lowest COE, the annual cost of electricity would be approximately \$51,646,482 annually (using a figure of 809,506 MWh annually). Compared to amine capture costs, the cost of membrane capture technology is significantly higher. Therefore, the total cost calculation will not include membrane technology.

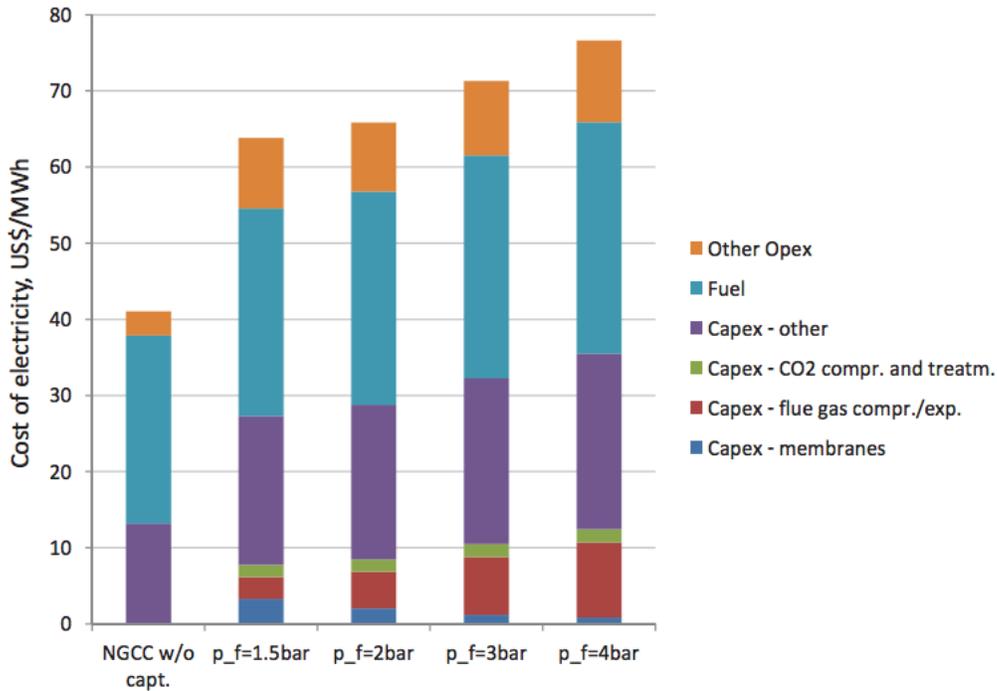


Figure 12: Effect of membrane feed pressure on efficiency and total membrane surface area. Adapted from (Voleno et al., 2014)

Cost of New Build NGCC Power Plants with Post-Combustion Capture (Rubin and Zhai, 2012)

To provide a second estimate of the cost of adding CCS to the Yale power plants, I use figures from a 2012 study (Rubin and Zhai, 2012) that examined the cost of CCS for natural gas combined cycle power plants. The study took a systematic approach for plants with amine-based post-combustion CCS system with 90% CO₂ capture. The study examined the assumptions and cost results of various NGCC plants without CCS (reference plants) and with CCS plants using figures given by the Department of Energy (DOE), Energy Information Administration (EIA), National Energy Technology Laboratory (NETL), and the industry-sponsored Electric Power Research Institute (EPRI). Table ## summarizes these assumptions and results of three recent studies of US natural gas combined cycle power plants.

All studies used General Electric 7FB gas turbines with an average net power output of 555 MW for the combined cycle plants, 90% capture of flue gas, pipeline transport and CO₂ storage in a deep geological formation. In all cases of CCS installation, plant with CCS installed experienced reduced the net plant efficiency and net power output, and increased cost of electricity generation.

Case	Parameter	DOE/NETL (2007)	DOE/NETL (2010)	EPRI (2009)
Reference plant without CCS	Net Power Output (MW)	560.4	555.1	550
	Total Plant Cost (\$/kW)	554	584	800
	Levelized COE (\$/MWh)	68.4	74.7	85.3
Same Plant With CCS	Net Power Output (MW)	481.9	473.6	467.5
	Total Plant Cost (\$/kW)	1172	1226	1370
	Levelized COE (\$/MWh)	97.4	108.9	121.1
Cost of CCS	Levelized COE (\$/MWh)	29	34.5	35.8
	Cost of CO ₂ avoided (\$/tCO ₂)	92	106	95

Table 10: Summary of Assumptions and Results for Several Recent Cost Studies for U.S. Natural Gas-Fired Power Plant. Adapted from (Rubin & Zhai, 2012)

On average, the total plant cost with CCS increased by a factor of two. The study showed that CCS capture technologies added \$22-40 per MWh to the levelized cost of electricity (LCOE). Their analysis shows that a policy to encourage CCS at new NGCC plants by implementing an

emission tax or carbon price requires a price of at least \$125/t CO₂ to ensure NGCC-CCS is cheaper than a plant without CCS (at 95% confidence).

This analysis only applies to new plants, rather than reflecting the cost of retrofitting CCS to existing NGCC units. Therefore, the analysis is useful in understanding the cost of a new-build NGCC power plant with CCS compared to a reference plant, but it cannot be directly applied to estimating retrofit of Yale's CPP & SPP. Costs for retrofitting plants would be higher because 1) the capital cost of the capture unit is higher due to site-specific difficulties, such as limited space or access when installing retrofitting units, 2) financing costs are higher if the remaining plant life is short, 3) existing plants with older and less efficient gas turbines have higher CCS energy penalties and associated costs (Rubin & Zhai, 2012).

The analysis at least gives us an underestimate that a new-build NGCC power plant would cost double the cost of the current power plants. Julie Paquette, Director of Energy Management within the Office of Facilities, estimated that the cost to build CPP and SPP was between \$50 to \$70 million. Using to the estimates by Rubin & Zhai (2012), a retrofit of CPP & SPP with CCS technologies would likely exceed \$100 to \$140 million.

Limitations

The costs from Table 10 varied due to differences in assumptions about financial, technical, and economic factors. There are also differences in underlying cost estimation methods among the DOE, IEA GHG, and EPRI because there is no common method and nomenclature used by these institutions. A significant methodical difference is exclusion of the "owner's costs" in the DOE/NETL 2007 study, which include expenses for initial inventories, working capital, land purchases, financing, and royalty payments (Rubin & Zhai 2012). The 2010

DOE/NETL study includes these “owner’s costs.” These additional costs can increase the estimated capital cost of a power plant by 120%, which explains the increase in reported plant capital costs in the 2010 DOE/NETL study. These differences in assumptions and cost estimation methods complicates this paper’s estimation for CCS power plants.

There are also potential cost reduction technologies that are not considered when retrofitting power plants for CCS, such as innovations in flue gas recycle. Rubin et al. show that improved technologies could reduce future costs of carbon capture (Rubin et al, 2007).

Cost for NGCC & PCC Retrofit (Dillon et al., 2013)

Another study performed a technical and economical evaluation of the application of post-combustion capture (PCC) to natural gas combined cycle (NGCC) plants (Dillon et al., 2013). Dillon et al (2013) performed an economic analysis of 1) new NGCC plant with no capture, 2) NGCC plant retrofitted with post-combustion capture, 3) new build NGCC plant designed with PCC + EGR, and 4) new build NGCC designed with PCC.

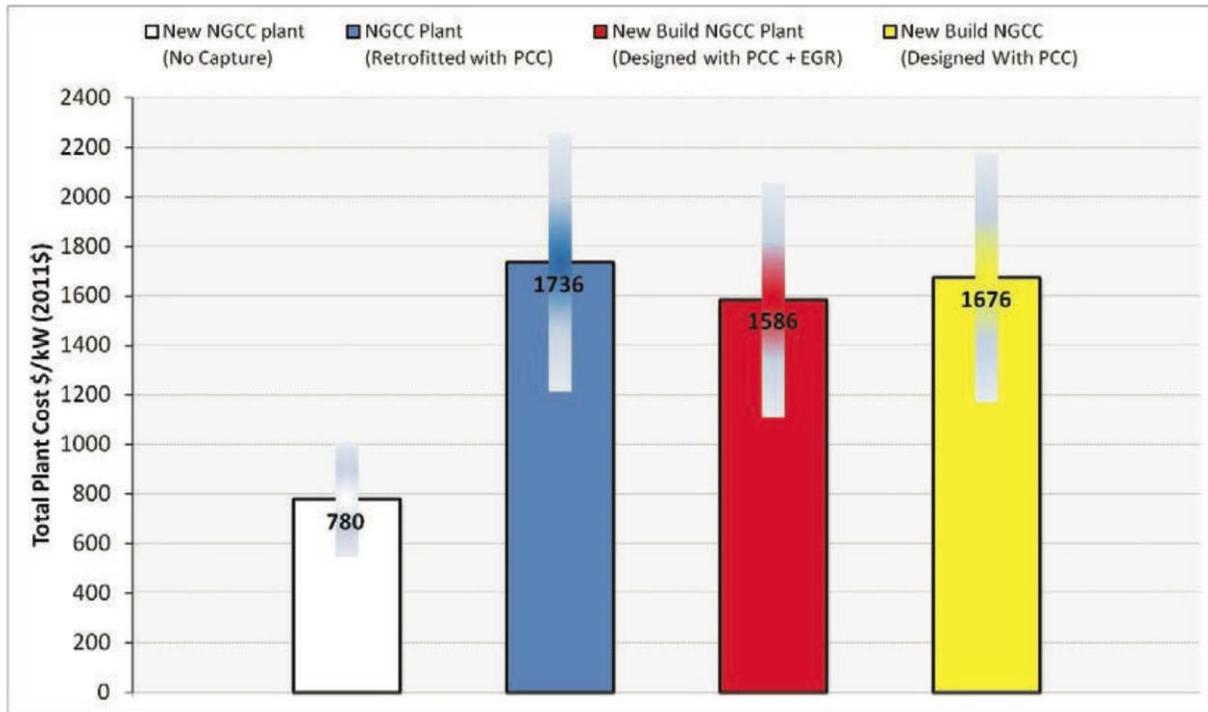


Figure 13: Total plant cost with and without CO₂ capture (Dillon et al., 2013).

The most relevant cost estimate is NGCC plants retrofitted with PCC, which is the case for the Central and Sterling Power Plant. The figure shows that the cost for NGCC plants retrofitted with PCC would be more expensive than building a NGCC plant from scratch. The cost analysis that the costs associated with a retrofitted plant will be higher compared to a new-build plant is consistent with the analysis by Rubin & Zhai. A cost estimate for total plant cost scaled by CPP & SPP's capacity is approximately \$57,288,000 for both plants (33MW). Taking the difference between the plants retrofitted with PCC and plants with no PCC gives an estimate of US\$31.5 million for a retrofit of the Yale plants (33 MW). This is comparable to the estimate of US\$24.1 million for amine capture technology, based on Darton (2011).

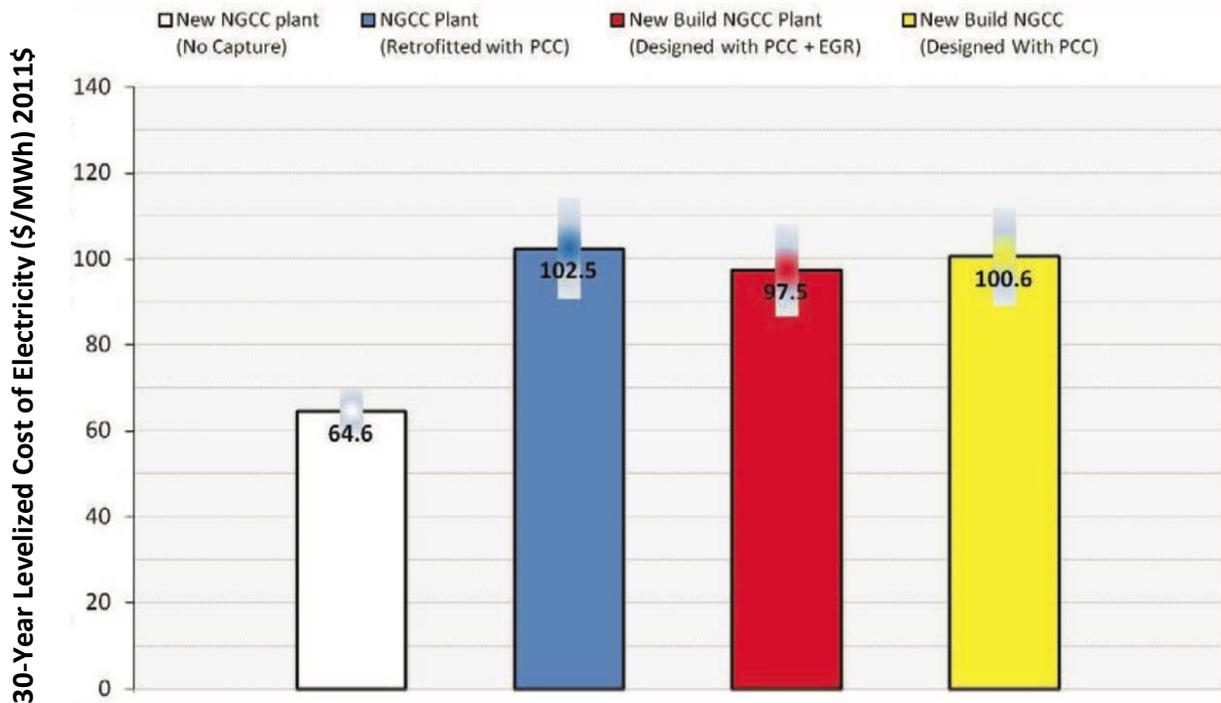


Figure 14: LCOE with and without CO₂ capture in \$/MWh (2011 \$). Source: Dillon et al, 2013

This figure shows that the levelized cost of electricity for a retrofitted NGCC plant with PCC is the highest, as of 2011. Given that the total energy output by CPP & SPP in 2016 was 809,506 MWh, an estimated LCOE with post-combustion retrofit is \$82,974,365 in 2011\$. Taking the difference for LCOE between the plants retrofitted with PCC and plants with no PCC gives an estimate of \$30,680,277 for running the amine capture technology. Annual cost of electricity would be approximately \$1.02 million.

Alternatively, the cost of running the amine capture technology can be roughly approximated by estimating the cost for fuel associated with the additional load of electricity needed to run the capturing process. DOE/NETL analyses suggest that today's commercially available post-combustion capture technologies result in a 20 to 30 percent decrease in efficiency due to parasitic energy requirements. We will assume a 30% parasitic energy requirement and \$4/Mcf for natural gas. The cost of additional fuel is calculated using our

previously determined total energy production in MMBtu, converted to Mcf, which yields \$3,884,187.

Compression Technologies & Costs

CO₂ must be compressed to a supercritical phase in order to increase efficiency for transport. Gas compression has been well developed in the natural gas industry, using matured technologies, typically found in large scale fertilizers manufacturing plants i.e. production of urea (IEAGHG, presentation). CO₂ compression also uses similar equipment for natural gas compression. The main operating challenges of CO₂ compressors are preventing corrosion and hydrate formation. The different varieties of compressors include centrifugal and reciprocating, though centrifugal compressors are usually preferred for large volume applications (Wong, 2006).

The amount of compression required for transport is determined using a phase diagram, which shows the relationship between pressure and temperature for CO₂. The phase diagram shows the critical point, where pressure is 7.38 MPa and temperature is 31.4 degrees C. The supercritical phase of CO₂ exists at above this critical pressure and at higher temperatures than -60 degrees C (Figure 15).

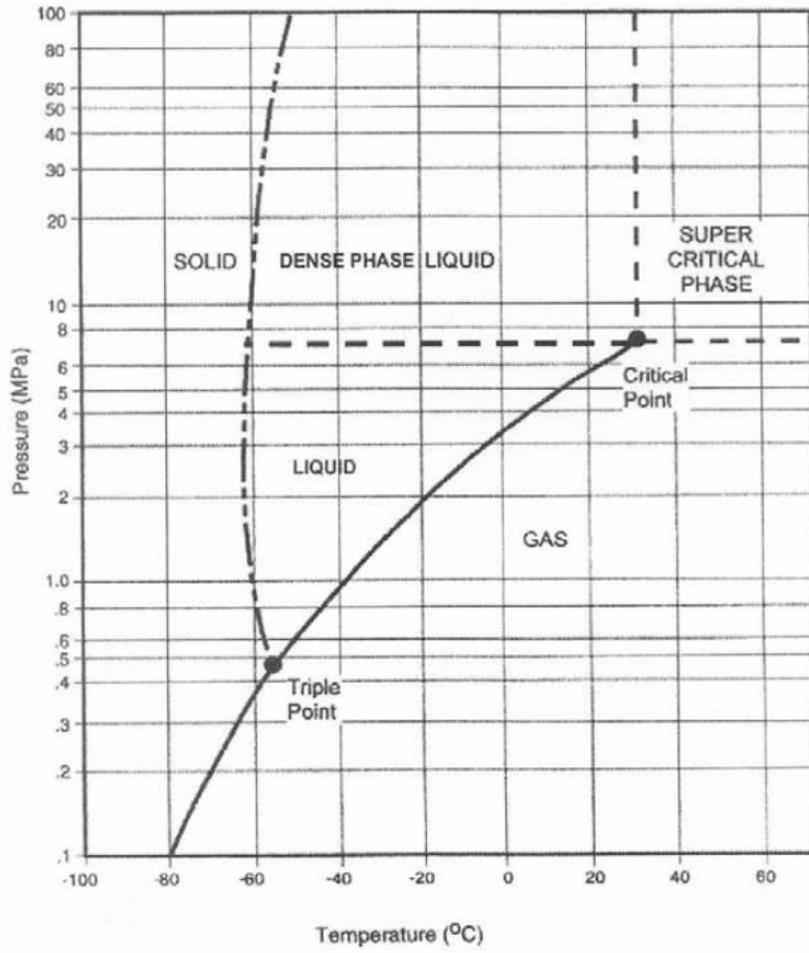


Figure 15: Phase Diagram of CO₂.

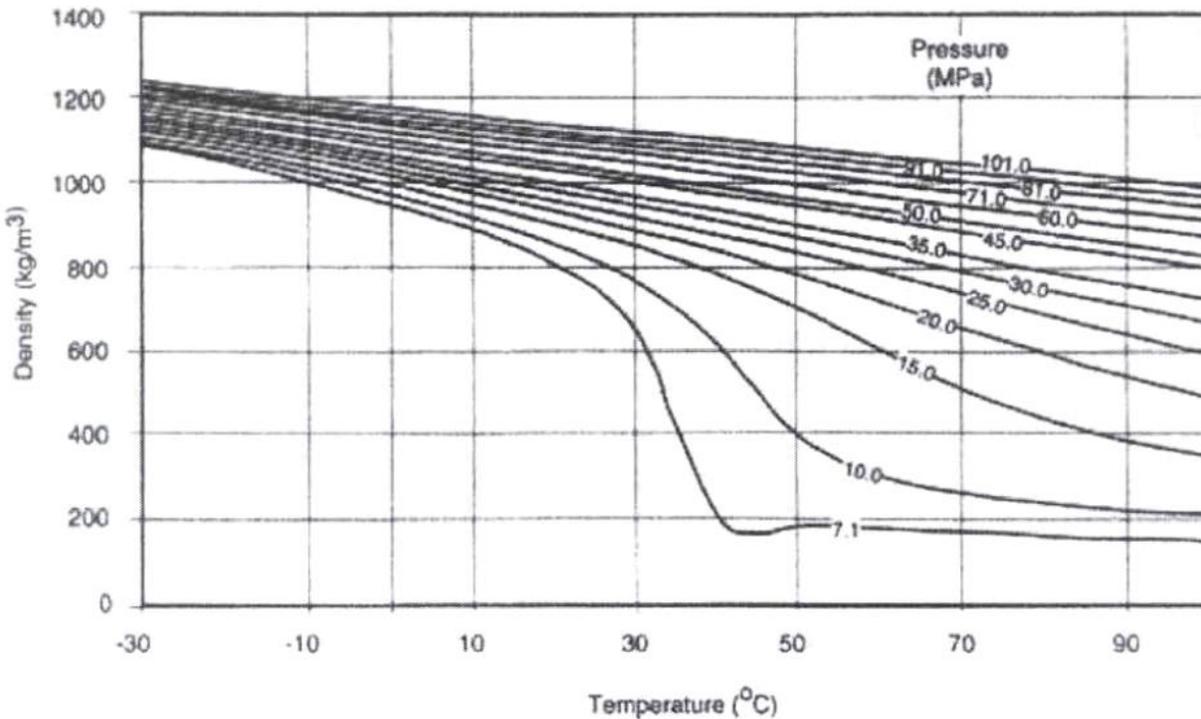


Figure 16: Density Diagram of CO₂.

Figure 16 shows the relationship between pressures and temperatures of CO₂. Above the critical pressure of 7.38 MPa and at temperatures lower than 20 degrees C, CO₂ has density between 800 and 1,200 kg/m³. Because transporting a dense liquid is easier than a gas, higher densities are favorable for transporting liquid, and compressing CO₂ to above 7.38 MPa is typical for efficient transport.

Compression of a gas ten to twenty-fold in one step would significantly raise the temperature of the gas, therefore many stages of compression is necessary to achieve an optimal pressure for the transport of the CO₂ (Wong, 2006). A four-stage compressor will need aerial coolers to cool the process CO₂ stream to appropriate temperatures between stages, and can achieve discharge pressure as high as 33 MPa. CO₂ compression is typically 80% efficient, with 119 kWh per tonne of CO₂ of required energy for compressing CO₂ to 14 MPa.

In 1998, more than 25 million tonnes of CO₂ were captured, compressed, transported, and injected to recover nearly 150,000 barrel/day of oil through CO₂ enhanced oil recovery (EOR) schemes in the Permian basin in the USA to (Stevens et al., 2000). The Dakota Gasification Plant in Saskatchewan, Canada, Aneth Field in Utah, and Williston Basin in North Dakota are examples of large volume applications that illustrate that there are many operating experiences in compressing and handling CO₂ in large-scale applications (NETL, EOR Primer.

ITEM (from Wong, 2013)	COST
Total CO₂ compressed (tonnes)	184,100
Capital charges (12% per year, 25-year life)	570,000
Labor & Maintenance	201,000
Energy cost (\$4 per GJ)	450,000
Total cost (US \$)	1,221,000
Compression cost per tonCO₂	\$6.6

Table 13: Annual cost of operating the compressor (\$/year). Adapted from (Wong, 2006)

The cost of CO₂ compression is typically a small fraction of the total cost of CCS. Wong estimates that a compressor with annual cost of \$1,221,000 would compress 184,100 tonnes per year and cost \$6.6 per tonne of CO₂ (Table 13). Yale power plants produce a total 148,318 tonnes of CO₂ for both fuel oil #2 and natural gas, which will cost of \$978,898 for CO₂ compression.

Transportation Costs

Based on a survey of North American pipeline project costs, (1) the cost of construction per unit distance is lower, the longer the pipeline for a given pipeline diameter, (2) pipelines near populated areas are generally more expensive, (3) highways, rivers, roads, or channel

crossings and marshy/rocky terrain will increase costs [True, 1998]. Pipeline costs are estimated based on material (line pipe, pipe coating, cathodic protection, and telecommunication equipment), labor, miscellaneous (cover surveying, engineering, supervision, contingencies, allowances for funds, administration, and regulatory filing fees), right-of-way, and damages (Smith, 2016). These costs were filed with the United States' Federal Energy Regulatory Commission and reported in the *Oil and Gas Journal*.

Shipping CO₂ is most economical and efficient when in the supercritical phase. According to the IPCC, transporting CO₂ 250km can cost between \$1 and \$5/tonne of CO₂, depending on the flow rate of the pipeline (IPCC, 2005). In 2005, CO₂ pipelines were a mature technology, with installed capacity stretching over 3000 miles in the US. There have been some additions to this network since then (Suresh, 2010), but costs have remained the same due to lack of technological developments.

At 10 million metric tons per year, transport costs are below \$1 per metric ton of CO₂ per 100 km. Transporting CO₂ over moderate distances, such as 500km, would be technically and economically feasible. In a 2013 study, NETL estimated an operational cost of about \$3.65 per tonne of CO₂ per 100 km.

The main challenge is constructing the pipeline infrastructure. Implementing a pipeline network would require a critical mass of capture plants to feed CO₂ into the network but without the infrastructure to begin with, development of CCS projects will be difficult (Herzog, 2011). For this reason, Yale would likely not tap into any existing networks of pipelines and would likely rely on vehicles to transport its liquid CO₂.

Wong estimates that the trucking cost is US \$3.5 per km for a 15-20 tonne truck with the truck return empty, or about US \$17 per tonne of CO₂ per 100 km or farther. Boil-off loss during truck transport is another complication for CO₂ transport. Boil-off can be as high as 10% of the CO₂ depending on the length of time the CO₂ is kept in the truck. The combined yearly CO₂ emissions at Yale is approximately 148,317 tonnes of CO₂, which will require approximately 5000 vessels annually, using the maximum vessel size of 30 tonnes of CO₂. These current vessels to transport CO₂ are typically used for food and beverage industries, so the volumes are not large enough to accommodate the transportation for CCS.

The railway system has a larger capacity to transport large volumes of bulk commodities over long distances, such as CO₂. Specially developed tank cars that are approved to transport liquid CO₂ at pressure 2.6 MPa, which can load 60 tonnes of CO₂ per tank car. The combined yearly CO₂ emissions at Yale is approximately 148,318 tonnes of CO₂, which will require approximately 2500 tank cars annually. There is currently no large-scale CO₂ transport via railway. However, rail transport can become competitive if the existing railway system can accommodate the volumes of CO₂ needed for CCS.

Mt. Simon Sandstone Formation

Mt. Simon Sandstone Formation (Mt. Simon) in the Illinois Basin, IL is a feasible option for CO₂ injection for Yale's carbon emissions. The U.S. Department of Energy (DOE) announced in April that the Illinois Industrial Carbon Capture and Storage (ICCS) project in Decatur, Illinois began CO₂ injection into a large saline reservoir (DOE, 2017). ICCS was a large-scale demonstration project that involved an integrated system for collecting CO₂ from an ethanol production plant and storing the CO₂ in a deep underground sandstone reservoir. The ICCS

project received a \$141 million investment from DOE, matched by over \$66 million in private-sector cost share.

The ICCS project demonstrates the feasibility of industrial carbon capture and storage technologies. Natural gas has been stored in the Mt. Simon Sandstone for fifty years, indicating that the saline reservoir and overlying seals can effectively contain the stored CO₂ (DOE, 2017). The CO₂ is injected into the Mt. Simon Sandstone in the Illinois Basin, which is one of the largest saline aquifers in the world. The project has storage capacity of approximately one million tons of CO₂ per year at depths of about 7,000 feet, but researchers estimate the sandstone formation has the potential storage capacity of more than 250 million tons of CO₂ per year.

Transportation Costs to Mt. Simon Sandstone Formation

The Mt. Simon Sandstone Formation is a promising geological formation for Yale to store its carbon. The Mt. Simon Sandstone Formation is approximately 1000 miles (1600 km) from Yale University. Using NETL's pipeline cost estimate, the cost for pipeline transportation is approximately US\$8.8 million. Using Wong's estimate of \$17 per tonne of CO₂ per 100 km or farther, transporting the supercritical fluid to the injection site will cost US \$272 per tonne of CO₂. Assuming that annual emission at CPP and SPP is 148,318 tonnes of CO₂, the total annual cost of transporting 148,318 tonnes of CO₂ to the Mt. Simon Sandstone Formation is approximately \$40,342,496 per year.

Transporting CO₂ via pipeline will be cheaper, though not as feasible. The high cost for transportation via trucks will certainly pose a challenge for Yale to incorporate CCS technologies into its power plants. However, advantageous siting near New Haven could significantly reduce the transportation costs. The Mt. Simon Sandstone Formation is only one option that is

currently available for carbon sequestration. Future exploration and research into saline aquifer sites can open new possibilities for an economically attractive injection sites.

Cost of Storage & Monitoring

Cost of storage will depend on geological characteristics of the injection formation, such as the reservoir thickness, permeability and effective radius that affect the amount and rate of CO₂ injection and therefore the number of wells needed. There are also costs for licensing, geological, geophysical and engineering feasibility studies required to select and evaluate a suitable geological site, and in-field pipelines required to distribute and deliver CO₂ from centralized facilities to wells. Operating costs include manpower, maintenance and fuel, and monitoring the wells for potential leaks.

ICF International in cooperation with the US DOE and EPA, has estimated the costs of geologic storage by storage option in the US. The total costs of CO₂/tonne ranges from \$4.28 for onshore depleted gas reservoirs storage to -\$66.25 for onshore EOR, where negative value implies a credit as opposed to a cost (Vidas, Hugman, & Clapp, 2009). The International Energy Agency estimates a range of \$4 – \$12 per tonne. The variability is based on different injection properties, transportation, and storage site (Adams & Davison, 2007). The wide range in cost estimates is attributable to high sensitivity to widely varying input parameters for the economics of transportation and storage. Ultimately, accurate estimates of both transportation and storage methods is very difficult (Allinson & Nguyen, 2003).

The 2005 IPCC Special Report on CCS estimates costs of about 0.4 – 4.5 US\$/tCO₂ stored for saline aquifer storage. Based on the costs in their table below, applied to the Mt. Simon Formation and the volume of CO₂ from the Yale plants, the range of storage costs for Yale

\$59.3k to \$667.4k annually. The IPCC estimates monitoring costs for saline aquifer wells are 0.1 – 0.3 US\$/tCO₂. Monitoring will add an additional US\$ 14,831 – 42,639 to the cost of storage.

Option type	On or offshore	Location	US\$/tCO ₂ stored			Comments	Nature of Midpoint value
			Low	Mid	High		
Saline formation	Onshore	Australia	0.2	0.5	5.1	Statistics for 20 sites ^a	Median
Saline formation	Onshore	Europe	1.9	2.8	6.2	Representative range ^b	Most likely value
Saline formation	Onshore	USA	0.4	0.5	4.5	Low/base/high cases for USA ^c	Base case for average parameters
Saline formation	Offshore	Australia	0.5	3.4	30.2	Statistics for 34 sites ^a	Median
Saline formation	Offshore	N. Sea	4.7	7.7	12.0	Representative range ^b	Most likely value
Depleted oil field	Onshore	USA	0.5	1.3	4.0	Low/base/high cases for USA ^c	Base case for average parameters
Depleted gas field	Onshore	USA	0.5	2.4	12.2	Low/base/high cases for USA ^c	Base case for average parameters
Disused oil or gas field	Onshore	Europe	1.2	1.7	3.8	Representative range ^b	Most likely value
Disused oil or gas field	Offshore	N. Sea	3.8	6.0	8.1	Low/base/high cases for USA ^c	Most likely value

Total Costs

The final cost is between US\$46.97 million and US\$14.53 million. For comparison, Yale's total annual utility bill is about US\$100 million. Yale is instituting a carbon charge of \$40/ton CO₂ or about \$6 million for 150,000 ton of CO₂.

STAGE	TECHNOLOGY	Annual COST
Capture (Dillon et al., 2013), 30 yrs amortized	Amine scrubbing	1,051,600
Capture (Darton, 2011), 30 yrs amortized	Amine scrubbing	800,000
Compression	Compressor	978,898
Transportation	Pipeline	8,760,000
Transportation (1600 km)	Trucks	40,342,496
Transportation (160 km)	Trucks	4,034,250
Storage (min)	Saline aquifer	59,327
Storage (max)	Saline aquifer	667,431
Monitoring		42,639
Load factor (extra cost of fuel to run CCS)	Natural gas at \$4/Mcf	3,884,187
Maximum annual cost		46,967,251
Minimum annual cost		14,525,051

Environmental Concerns

Although CCS can reduce the threat of climate change through the greenhouse effect, the benefits of CCS must be weighed with potential environmental and social costs. CCS can only be truly effective in mitigating climate change if it's sustainable. This means that CCS 1) must deliver environmental and social benefits that exceed its costs of capital, energy and operation, 2) does not endanger the environment and human health long term, and 3) should be deployable on a large scale.

Application of CCS at CPP & SPP, transportation and storage of the carbon should not further endanger the state of the environment and communities that may be affected by CCS. The storage area for sequestration products should be lined or sealed to prevent ingress of rainwater and groundwater because the reaction of sulfurous acid rain with limestone or dolomite produces carbon dioxide and a layer of insoluble calcium or magnesium sulfate (IEAGHG, 2000).

Conclusion

Carbon capture and storage (CCS) is a promising option in the portfolio of mitigation actions for stabilization of atmospheric greenhouse gas concentrations. CCS involves the separation of CO₂ from industrial and energy-related sources, transport of the carbon to a storage location, and long-term storage that minimizes leakage to the atmosphere. The widespread application of CCS will depend on cost, technical maturity, potential for applying the technology in developing countries, as well as regulatory aspects, environmental issues and public perceptions of the technology. This paper focuses the economic feasibility of implementing CCS at Yale's two power plants by examining the cost associated with capture,

compression, transportation, and storage of captured CO₂ emitted by Yale. The final calculated cost of CCS ranges from US\$14.5 million to US\$46.9 million annually. We considered storage at Mt. Simon Sandstone Formation, located in Illinois. The immense distance between Yale and the storage site was the root of high transportation costs, which dominated the full cost of CCS.

Due to the high transportation costs associated with injecting CO₂ into a saline aquifer, another storage method was investigated – mineral carbonation. The advantages with in-situ mineral carbonation with regards to Yale is that basaltic rocks are abundant in the Northeast. A potential local storage site would significantly reduce transportation costs. Mineral carbonation is the chemical reaction between CO₂ and metal oxide bearing materials that form insoluble carbonates. A suitable metal oxide material to react with CO₂ is olivine minerals, which were used in the laboratory studies of mineral carbonation at Yale. A second part of this paper focuses on modeling the experimental results from the mineral carbonation study. The simulations varied the equilibrium constants and reaction constants by 2 orders of magnitude about set values for k and K . In all cases of the simulations, the coupled reactions saturate and the carbonation fraction plateaus, but does not decrease over time. This suggests that the simple kinetic model involving competition between olivine dissolution and magnesite and talc formation does not explain the main experimental result of the Yale mineral carbonation project. There are likely other complex reactions happening, which could involve precipitation of other magnesium-bearing silicates and interactions between ionic species in solution that change their activities.

Additional Discussion Sections

Among available abatement options, CCS is one of the more expensive and technically challenging carbon emissions abatement technology. However, the decision to determine if CCS is a sustainable mitigation strategy should rely not only on the cost per tonne of CO₂ abated, but on a holistic analysis of the tradeoffs involved in CCS, such as natural resources used, pollutants produced, energy demand, effects on biodiversity, human health, and any other environmental and social risks associated with the full life-cycle of CCS.

Carbon Pricing

According to the IPCC, integrated assessment models indicate that CCS systems will be competitive with other large-scale mitigation options. This assumes that society will impose limits on greenhouse gas emissions and impose a system for carbon pricing. Currently, the global economic system is not set up to measure or reward countries or firms for taking climate action. Instead, these firms act to maximize profits to stay in business or deliver shareholder returns. It is the responsibility of society and governments to regulate market activities in order to achieve desired social outcomes. A promising regulation method is through putting a price on carbon emissions to the atmosphere.

CCS would benefit from carbon pricing because employing this technology would create environmental and social benefits through reducing carbon emissions to the atmosphere. The benefit is quantified by expressing the value of the benefit as a social cost of carbon. The social cost can be quantified by estimating the value of the damage to society and ecosystems with each additional tonne of greenhouse gas emitted to the atmosphere. This social cost ranges from \$85/tCO₂ by Stern to \$25/tCO₂.

Most energy and economic models suggest that CCS systems become competitive when carbon prices started to reach approximately 25–30 US\$/tCO₂ (90–110 US\$/tC). These energy and economic models anticipate large-scale deployment of CCS systems within a few decades from the start of any significant regime for mitigating global warming (Herzog et al.)

Discussion on Carbon Neutrality with CCS

The application of CCS is an important step towards decarbonizing Yale’s campus and placing Yale as a leader in carbon neutrality. However, it’s important to note that 17% of Yale’s energy consumption is derived from an external electricity generation company, which is outside the scope of our analysis for CCS application. Therefore, Yale would not be fully decarbonized by simply retrofitting CPP & SPP with CCS technology. Yale must also adopt carbon offsetting projects and invest in renewable energy projects.

	Nat Gas (MMBTU)	#2 Oil (MMBTU)	Purchased Elec (MMBTU)	Total MMBTU
Sub Tot	2,678,383	83,650	549,236	3,311,270

Table 11: Yale’s Total Energy Consumption

As part of Yale's strong commitment to the goals of reducing the University's carbon footprint, the Yale University Endowment invested funds in the Record Hill wind power project in Roxbury, Maine. According to the YaleNews, The U.S. Department of Energy offered a conditional commitment for a \$102 million loan guarantee to fund the wind power project, which supported in installing a 22 turbine, 50.6-megawatt wind power plant, a transmission line, and associated interconnection equipment. The Record Hill project avoids over 70,000 tons of carbon dioxide annually, which accounts for approximately 30% of Yale’s annual emission of 230,000 tons CO_{2e} (YaleNews, 2011). We can determine how much carbon offsetting is

necessary for the purchased electricity using the wind farm. 549,236 MMBtu of purchased electricity is equivalent to 29,346 tonnes of CO₂. The wind farm project avoids 2.39 times more CO₂ than the purchased electricity produces.

However, the wind farm operation is not enough to bring Yale to carbon neutrality because we must also consider emission sources outside of the power plants. This paper estimates 148,318 tonnes of CO₂ annually, while the Yale Sustainability Office 2015 estimates that Yale emits 230,000 tons CO₂e annually. The difference between these two estimates is due to other sources of carbon emissions not directly from the power plants, such as transportation and refrigerants. Our calculation for 148,318 tonnes of CO₂ only considers the stationary combustion of natural gas and fuel oil #2 for year 2016, because we were only interested in determining the CO₂ emissions that could be captured for CCS.

Sum of Market-Based Emissions (tCO ₂ e)			Year	
Scope	Emission Category	Emission Source	2014	2015
1	Mobile Combustion	Mobile Biodiesel - CH ₄ +N ₂ O	0	0
1	Mobile Combustion	Mobile CNG	142	127
1	Mobile Combustion	Mobile Diesel	1,338	1,015
1	Mobile Combustion	Mobile Gasoline	1,835	2,173
1	Refrigerants & Fugitive	HFC-134a	3,664	2,585
1	Stationary Combustion	Fuel Oil #2	18,860	40,892
1	Stationary Combustion	Natural Gas	218,854	171,416
1	Stationary Combustion	Propane	78	63

1	Stationary Combustion	Stationary Biodiesel - CH ₄ +N ₂ O	0	-
1	Stationary Combustion	Stationary Diesel	43	12
2	Purchased Utilities	Electricity	48,220	65,354
2	On-Site Generation	Electricity - Renewable	-	-
Grand Total			293,034	283,637

Table 12: Total Anthropogenic Emissions - Market-Based. Adapted from Yale University GHG Emissions Data, Julie Paquette

Table 12 lists all of Yale’s emission sources and emissions in tCO₂e for year 2014 and 2015. (The full emissions data for 2016 was unavailable). Yale’s CO₂ emissions includes refrigerant and fugitive emissions, stationary combustion, and purchased utilities. Stationary combustion involves the energy generation from the CPP & SPP. Though earlier sections of this paper focused only on the emissions sources that produce carbon dioxide from the two power plants, it’s important to understand the other sources of anthropogenic emissions, such as fugitive emissions, that contribute to climate change and should be addressed through carbon offsetting programs to achieve carbon neutrality at Yale.

Fugitive emissions are greenhouse gases from various types of equipment and processes that are directly released to the atmosphere. Common sources include refrigeration, air conditioning, fire suppression systems, and the purchase and release of industrial gases (EPA, 2016). Yale uses HFC-134a (CH₂FCF₃), a refrigerant with a lifetime of 14.6 years, GWP of 3400 in a 20-year time horizon and GWP of 1300 in a 100-year time horizon (UNFCCC, 2016). Global warming potential allow comparisons of the global warming impacts of different gases. GWP is

a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time (usually 100 years), relative to the emissions of 1 ton of carbon dioxide (EPA, 2016). In 2015, Yale produced 2,585 tonnes of tCO₂e through HFC-134a, which is not negligible in terms of global warming potential. Therefore, a combination of carbon offsets through investment in clean energy and application of CCS technologies at Yale's power plants is necessary to fully decarbonize the campus.

The Cost of CO₂ Avoided & Carbon Pricing

Pricing greenhouse gas emissions can establish markets for low-carbon technologies like CCS. The cost of CO₂ avoided in \$/tCO₂ corresponds to a carbon price. The cost of CO₂ avoided is the cost of reducing CO₂ emissions while generating the same amount of energy from a reference plant, expressed as \$/tonne of CO₂ not emitted. A power plant incorporating CCS technology will reduce CO₂ emissions, but will also generate additional CO₂ per unit of energy with respect to the reference plant because of lower plant efficiency due to increase auxiliary power needed to run the capture process. Rubin & Zhai (2012) found that the average cost of CO₂ avoided is \$98/tCO₂, which corresponds to the average carbon price for the three plants from Table ## (from above). The carbon tax will make CCS economically attractive because the NGCC plant with the 90% CO₂ capture will have a lower LCOE than the uncontrolled plant.

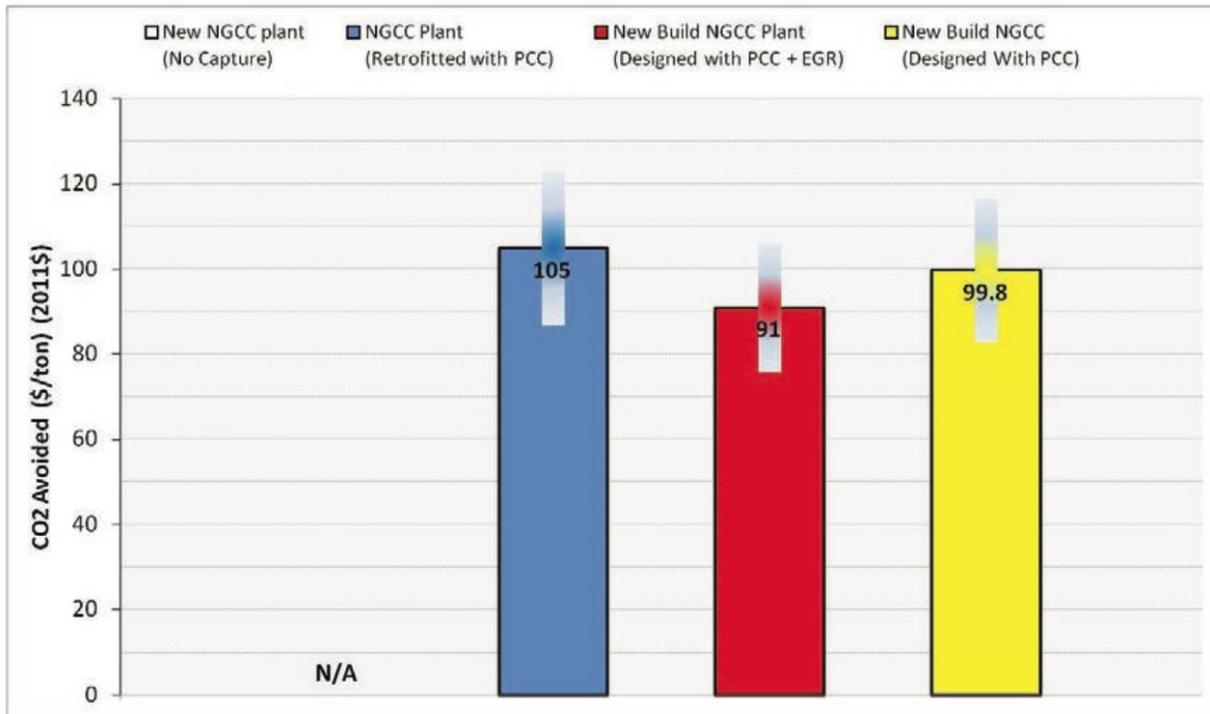


Figure 17: Cost of CO2 avoided

In figure 17, Dillon et al (2013) estimates the CO₂ avoided for an NGCC plant retrofitted with PCC technologies will translate to a carbon price of \$105 per ton of CO₂ (in 2011\$). This cost estimate is similar to the cost estimate by Rubin & Zhai (2012) for new build NGCC plants (\$98/tCO₂).

The plant must have a carbon price at or above the value of the cost of CO₂ avoided because a plant with a carbon price lower than that value will render the NGCC plant without CCS more economical. Therefore, Yale must implement carbon pricing to render CCS at the Central and Sterling power plants economical. The carbon price will be equivalent to the cost of CO₂ avoided at the Central and Sterling power plants. The CO₂ avoided is calculated using the total CO₂ produced by the plant, CO₂ emitted from the plant based on percent capture, and CO₂ emitted from the extra capacity of adding CCS. DOE/NETL analyses suggest that today's

commercially available post-combustion capture technologies result in a 20 to 30 percent decrease in efficiency due to parasitic energy requirements. We will use 30% parasitic energy requirements and calculate the CO₂ avoided, with constant energy output by the power plants.

*CO₂ Avoided = (Total CO₂ produced by the plant) – (Total CO₂ produced by the plant + CO₂ emitted from the extra capacity of adding CCS) * (1 – % energy penalty)*

*This amounts to 148,318 tonnes of CO₂ – (148,318*0.1) – (148,318*0.3*0.1) = 129,036 tonnes of CO₂.*

The amount of CO₂ avoided taking into account energy penalties is 87% of the CO₂ produced from the power plant. Employing CCS would avoid approximately 129,036 tonnes of CO₂ per year. Using the carbon price estimate \$105 per ton of CO₂, then Yale would need to implement a carbon price of \$13,548,849 per year.

Public Concern of CCS

Successfully implementing new energy technologies depends on technological developments, economic profits, and societal acceptance. Hisschemoller and Midden, 1999 detailed examples of the delays and stagnation in science and technology development due to social opposition. Emerging technologies will bring considerable uncertainty and risks. Lay persons may not have sufficient information to adequately weigh the costs and benefits in these circumstances. However, trust can engender willingness to be vulnerable under conditions of risk and interdependence (Rousseau et al., 1998). Acting on trust can be an alternative to acting on full knowledge (Siegrist and Cvetkovich, 2000). Trust can increase tolerance of uncertainties, openness to new information, and allow people to make decisions

and enjoy the benefits of new and potentially risky technologies, even without fully understanding all the details (Siegrist and Cvetkovich, 2000).

With regards to CCS, a study by Midden and Huijts (2006) suggests that feelings of trust in government and in industry lead to increased positive and negative affects towards CCS, which then influence the perception of risks and benefits, and acceptance of CCS. The study found that public attitudes in general were slightly positive, but attitudes towards storage nearby were slightly negative. The general public had limited knowledge of CO₂ storage but had little desire to learn more (Huijts and Midden, 2007). The study also found that the general public had greatest trust in NGOs and the least trust in industry. The levels of trust were likely based on perceived competence and intentions, which are based on perceived similarity in goals and thinking between trustee and trustor. While professional actors use facts and analyses of all possible outcomes to evaluate science and technologies, citizens rely more on feelings related to the technology and trust in the actors involved in the technology, rather than on detailed information of the technology (Huijts and Midden, 2007).

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