

Assessment of CO₂ Sequestration Options and Other Environmental Impacts Related to the Proposed Coal-to-Liquids Plant at Eielson Air Force Base

Prepared for the U.S. Air Force

by

**Geophysical Institute
University of Alaska Fairbanks
and the
Alaska Center for Energy and Power
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DISCLAIMER

Any opinions, findings, and conclusions or recommendations expressed in this material are those of the author(s) and do not necessarily reflect the views of the United States Air Force, Air Force Research Laboratory.

EXECUTIVE SUMMARY

During summer 2009, the U.S. Air Force contracted with the Alaska Center for Energy and Power and the Geophysical Institute at the University of Alaska Fairbanks to provide a literature-based summary of options for carbon dioxide (CO_2) sequestration and/or mitigation for a proposed coal-to-liquids (CTL) plant near Eielson Air Force Base, and to identify other possible pollutants. This report summarizes those findings, and includes our conclusions and recommendations for future work.

After considering all possible geologic sequestration options, it was determined that the most viable option of sequestering the CO_2 generated by a proposed CTL plant is to use the CO_2 in enhanced oil recovery in North Slope petroleum fields. While the technology exists for this method, it would require construction of a 500-mile pipeline to ship the CO_2 from Fairbanks to the North Slope. Nonetheless, at this time, use of CO_2 for enhanced oil recovery is the only commercially demonstrated technology available for CO_2 sequestration.

Alternatively, closer to Fairbanks, CO_2 could be sequestered in deep coal seams near the Healy coalfields. While this option would require a significantly shorter pipeline (115 miles), the distribution of the coal seams at depth is not well understood and the sequestration technology is still being developed and tested. A third option, that of sequestering CO_2 in the Fairbanks area by reacting it with mafic rock either at depth or at the surface, is the most speculative of the options but would cost the least for transporting CO_2 .

Reducing CO_2 emissions by using biomass as feedstock on a large scale is currently not practical. With the current known growth rates, this method would require harvesting approximately one million acres of willows or a similar fast-growing shrub. Land suitable for production on this scale has not yet been identified, nor have harvesting, transporting, or drying costs been estimated. More research into increasing biomass production in Alaska is needed for a more definitive answer. Additionally, while mitigation of the large quantity of CO_2 produced by a CTL plant may not be completely feasible, biomass CO_2 mitigation may be more suitable for a smaller-sized plant, or as part of a series of mitigation efforts.

Pollutants directly related to the proposed feedstock coal from the Healy Usibelli Coal Mine were determined to have very low amounts of sulfur (especially pyritic sulfur), metallic trace elements, and nitrogen, as expected. The major gaseous emissions from a CTL plant would consist of SO_x , NO_x , particulate matter, CO, and CO_2 ; there would likely be some amount of trace elements in the gaseous emissions, as well. Given the cold climate of Alaska, particularly Fairbanks, water vapor emissions may be critical because of their impact on visibility. The major solid effluents would be dry ash or slag, and fly ash.

Ash disposal can be a problem especially if it is leachable. Slag is significantly easier to handle because it is inert and volumetrically smaller than dry ash. Water would be the major liquid effluent. Some of these pollutants could be addressed by ultra cleaning the coal and/or using a different gasification process than the one proposed.

A major operational concern is the effect of water vapor emission by the proposed CTL plant on visibility, especially during winter when ice fog conditions are common. To assess the potential impact on the mission of the base, a computer model was constructed that clearly showed a daily cycle of ice fog development related to the existing heat and power plant. Eielson meteorologists confirmed that such a cycle often occurs during the winter, suggesting that the computer model could provide an important predictive tool for evaluating the effect of the proposed CTL emissions on ice fog formation, although changes would be required to adjust for the different location and parameters associated with the proposed plant.

There is significant uncertainty about the likely cost of carbon capture and sequestration from a CTL plant sited on Eielson Air Force Base, because there are few operational facilities using applicable technologies that can be used as cost comparisons. Two different modeling approaches were used to estimate costs for CO₂ capture and sequestration: cost per ton, using costs from the economic literature, and capital and operating costs of CO₂ capture, transportation, and sequestration specific to the Eielson CTL facility. In general, the capital-cost method produced lower costs per ton and per gallon of output produced than the cost-per-ton analysis, with a wide range of potential costs depending upon sequestering location and full versus partial capture.

INTRODUCTION

Liquid fuels derived from crude oil are critically important to the world economy, providing energy that can be easily transported and stored. However, crude oil demand is increasing faster than reserves are being discovered, causing concern about both future availability and price.

Other options exist for creating liquid fuels, including the Fischer-Tropsch (FT) process, invented in Germany in 1923 and used by Germany during World War II. This technology, used in South Africa since the 1960s, converts coal to liquid hydrocarbons, and is of interest to the United States due to its vast known coal reserves. However, this technology has not been widely adopted because of the availability of low-cost crude oil and the high capital cost of building the processing plants. Additional concerns arise due to greenhouse gas emissions, as the conversion of fuels to liquids through the FT process requires energy, and therefore creates additional CO₂ emissions.

Rising crude oil prices are affecting residents of Interior Alaska, where the limited availability of natural gas or cheap electricity has resulted in very high local energy costs. In response to high energy costs in Interior Alaska, a “Cost of Energy” Task Force was convened during the summer of 2007 by the Interior Issues Council to consider options for meeting the current and future energy needs of Interior Alaskan residents and businesses. This meeting culminated in a series of recommendations, including further study of options for siting a coal-to-liquids plant in the Interior. This plant could supply liquid fuels to the Interior from local coal resources beyond the life of the Trans-Alaska pipeline, which currently supplies a significant portion of liquid fuel to the Interior.

In early 2008, the Fairbanks Economic Development Corporation (FEDC) obtained funds from the Fairbanks North Star Borough and the Alaska Energy Authority to commission a preliminary design of this concept for the Interior. The publicly stated goal of this project was to provide fuel for the residents of the Fairbanks North Star Borough at reasonable cost, using local resources such as coal and biomass, through construction of a plant owned by a public entity. One of the major potential customers for this plant is the Eielson Air Force Base, and a plan to site the plant on the base was put forward.

Hatch Engineering of Toronto, Canada, was selected to complete the analysis, and based their design on a plant that would use Alaskan coal as the primary feedstock, with FT liquids as the primary product. The proposed plant would also supply some heat and electrical power to the local community. Carbon dioxide was to be separated for sequestration, but the place and method of sequestration was not defined, and the costs of transporting or injecting this CO₂ were not included in the estimates.

The report that follows is a summary of the existing literature that provides information needed to address options for CO₂ sequestration and mitigation associated with the proposed coal-to-liquids plant, including

- Options for geologic sequestration (Chapter 1).
- Opportunities for biologic sequestration and reduction of CO₂ emissions by varying feedstock (Chapter 2).
- Other possible options for carbon management or disposal, including compilation of information on CO₂ sequestration demonstration projects worldwide (Chapter 3).
- A basic economic and financial analysis of the most promising sequestration options/opportunities (Chapter 4).
- Other pollutants and wastes associated with the gasification of low-rank subbituminous coal from the Healy Usibelli Coal Mine (Chapter 5).
- Modeling of atmospheric dispersion of water vapor and other pollutants, and related visibility concerns at the Eielson Air Force Base (Chapter 6).

CHAPTER 1

Assessment of Options for Geologic Sequestration

by Catherine Hanks and Paul Metz

Introduction

Many recent studies have explored geologic sequestration of CO₂ (IPCC, 2005). Most geologic options fall into three broad categories:

- A. Storing CO₂ as a gas or gas-saturated fluid in underground porous and permeable rocks. Geologic options under this category include depleted hydrocarbon reservoirs; deep, unmineable coals; sedimentary rocks containing high-salinity fluids; organic-rich shales; salt caverns; and abandoned underground mines.
- B. Using the CO₂ to displace hydrocarbons currently stored in the subsurface. These options include enhanced oil recovery, enhanced coalbed methane recovery, and production of methane from gas hydrate deposits
- C. Chemically fixing CO₂ into carbonate minerals, thus locking it into solid form. This category includes injection of CO₂ into subsurface mafic rocks (e.g., basalts or ultramafics) or using quarried limestones or mafic rocks to fix CO₂ in solid form in a surface facility.

A variety of other factors should be considered when identifying the most appropriate geologic sinks for any one location, including the proximity to the CO₂ source, the geologic characteristics of the proposed CO₂ sink (e.g., porosity, permeability, and volume of available storage space), and the likelihood that the sequestered CO₂ will leak or migrate from the storage site.

In Interior Alaska, seven different geologic CO₂ sequestration options were identified:

1. Enhanced oil recovery in North Slope oil fields
2. Recovery of methane from North Slope gas hydrate deposits
3. Coalbed methane production and/or injection into deep coal seams in Nenana Basin coalfields
4. Injection into deep clastic basins and/or saline aquifers
5. Accelerated weathering of ultramafic rocks
6. Accelerated weathering of limestone
7. Injection into mafic volcanic rocks

These options are discussed in detail in this chapter.

After considering these possible geologic sequestration options, the most viable option of sequestering the CO₂ generated by the proposed coal-to-liquids (CTL) plant is the use of the CO₂ in enhanced oil recovery in North Slope petroleum fields. While this is a demonstrated technology, it would require construction of a 500-mile pipeline to ship the CO₂ from Fairbanks to the North Slope. Alternatively, and closer to Fairbanks, CO₂ could be sequestered in deep coal seams near the Healy coalfields. While this option would require a significantly shorter pipeline (115 miles), distribution of the coal seams at depth is not well understood and sequestration technology is still being developed and tested. A third option, sequestering CO₂ in the Fairbanks area by reacting it with mafic rock either at depth or at the surface, is the most speculative of the options, but has the fewest issues related to CO₂ transportation.

There are no depleted oil or gas fields in the Fairbanks area that could be used for geologic storage of CO₂. While Interior Alaska has several clastic basins, these are unlikely to serve as good CO₂ sequestration options, as they are not deep and/or are not well documented and/or do not have (or are not likely to have) the permeability seals needed to trap the CO₂ for a significant period. Injecting CO₂ into methane hydrate structures to recover natural gas has been demonstrated in the laboratory, but the technology to implement it at the field scale has not been developed.

Enhanced Oil Recovery from North Slope Oil Fields

Principles of CO₂ Enhanced Oil Recovery

Fluids such as water and oil are stored in the spaces between grains in a reservoir. Saline water is by far the most common fluid in the subsurface; when oil migrates into water-saturated reservoir rock, it displaces the water in pore spaces, but leaves a thin film of water on the grain surfaces.

The subsequent producibility of the oil from the reservoir is a function of the amount of water remaining in the rock and the structure of the pore/pore throat system. High water saturation will lead to early water production, as water generally flows more easily through the rock than the more viscous oil. Even in rock with high oil saturation, a large amount of oil remains when it is “stranded” in the rock by narrow pore throats and/or small pore spaces.

One method of recovering this stranded oil is enhanced oil recovery (EOR) via gas injection. In this technique, gas is injected into the reservoir and, under the right conditions, dissolves the oil in place. This gas/oil mixture has a lower viscosity and higher volume than the stranded oil, allowing the gas/oil mixture to flow more easily through the reservoir to the borehole.

Composition of the gas is important. The most commonly used gas for EOR is natural gas, which usually is predominately methane with small amounts of CO₂ and nitrogen. This gas is often produced from the same (or a nearby) field and is most readily available. Pure CO₂ has not traditionally been used in EOR, in large part because it has not been readily or economically available.

CO₂ Injection — Miscible vs. Immiscible

The major beneficial effect of CO₂ injection in an oil reservoir is when the gas becomes *miscible* or when the gas and the light hydrocarbons become mutually soluble. When this happens, the combined CO₂/hydrocarbon mixture is less viscous and has a higher volume, thus becoming more easily produced. The higher volume effect also helps displace heavier hydrocarbons left in the reservoir, as seen in Figure 1.1. Excellent pictures of miscible CO₂ and oil, with a reasonably clear explanation of the process, are available online at <http://www.mktechsolutions.com/Miscible%20Gas.htm>.

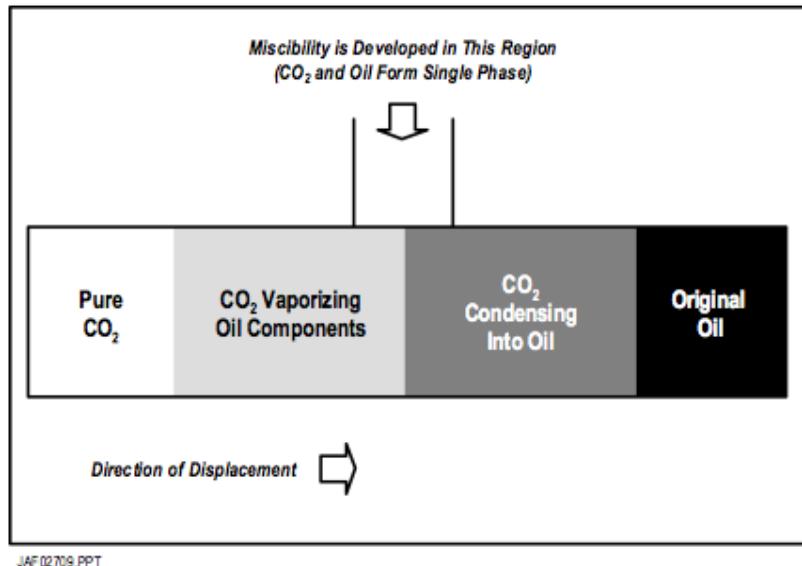


Figure 1.1. CO₂ miscible gas injection and subsequent sweep through reservoir (from Kuuskraa and Ferguson, 2008).

Recently, the CO₂ miscible gas injection technique has been improved by utilizing water alternating with gas (WAG) injection. In this procedure, pure CO₂ is injected alternatively with water. The location and behavior of CO₂ can be more closely monitored using this technique.

In a normal EOR scenario, CO₂ is an expensive commodity and is reused. To sequester CO₂, the gas would be injected into the reservoir until it began to be produced along with

the oil. Produced CO₂ would be separated from the oil and reinjected to continue oil recovery. When all the economically recoverable oil had been produced, the reservoir would be shut down at pressure, trapping all the injected CO₂ in place.

Miscible CO₂ gas injection is limited to reservoirs where hydrocarbons have significant light fractions and where pressures are high enough that the CO₂ and hydrocarbons can become mutually soluble. On the North Slope, this condition limits potential reservoirs to those fields with depths of >3000 feet and >25°API gravity and would include both the Prudhoe Bay and Kuparuk River fields (Advanced Resources International, 2005).

At depths of <3000 feet and/or API gravities <25°, CO₂ and the in-place hydrocarbons do not become mutually soluble and are considered *immiscible*. Carbon dioxide can be used for EOR and sequestered under these conditions, but the technology is still in development. North Slope fields that would be eligible for immiscible CO₂ injection would be shallower heavy oil fields such as West Sak and Milne Point.

Fields of Interest

Figure 1.2 shows the distribution of the main North Slope oil fields. Of these 32 fields, Advanced Resources International (2005) determined that 19 were amenable to CO₂ EOR. Since 2005, discovery of additional fields and increased industry interest in using CO₂ for EOR has undoubtedly increased the number of fields eligible for CO₂ sequestration.

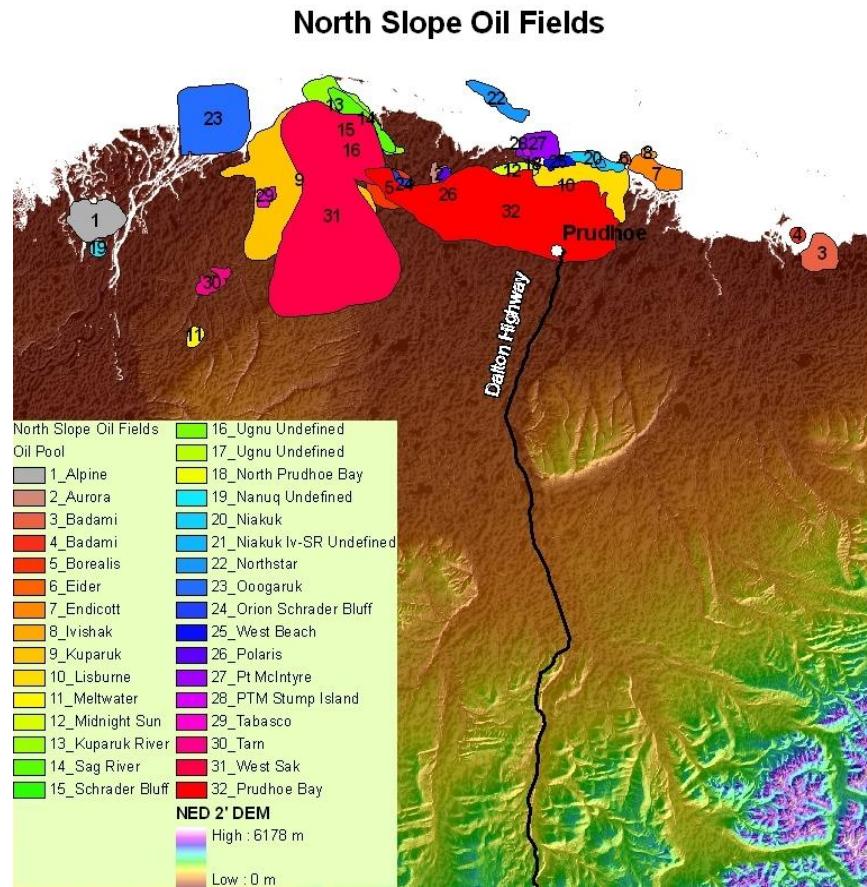


Figure 1.2. North Slope oil fields (from Advanced Resources International, 2005; GIS compilation by S. Panda).

Estimated Storage Capacity

Economic analysis by Advanced Resources International (2005) for the U.S. Department of Energy (DOE) suggests that if all 19 of the reservoirs amenable to CO₂ EOR were produced using this method, an additional 19.9 billion bbl (barrels) of oil would be recoverable (see Table 1.1).

Table 1.1. Estimated original oil in place (OOIP), cumulative recoverable oil, and residual oil in place (ROIP) for 21 North Slope reservoirs vs. North Slope reservoirs amenable to CO₂ EOR (from Advanced Resources International, 2005).

	No. of Reservoirs	OOIP (Billion Bbl)	Cumulative Recovery/Reserves (Billion Bbl)	ROIP (Billion Bbl)
All North Slope	21	62.2	20.3	41.9
Amenable to CO ₂ EOR	19	61.4	19.9	41.5

However, not all of these reservoirs are equally economical even with this additional recovery. Advanced Resources International (2005) suggests that 8 of the 19 reservoirs could be produced economically *if there was an inexpensive source of CO₂* (\$0.70/Mcf). According to this analysis, over 25 Tcf of CO₂ (“purchased” CO₂ in Table 1.2) would be sequestered during the course of EOR operations on these 8 fields.

Table 1.2. Economically recoverable oil from 8 major North Slope reservoirs using miscible CO₂ injection.

No. of Reservoirs	Economically Recoverable Oil (MMBbl)	Purchased CO ₂ (Bcf)	Recycled CO ₂ (Bcf)
8	7,600	25,100	80,100

Note: All CO₂ used in EOR would not necessarily be sequestered in the reservoir.

Viability of EOR with Respect to the Eielson CTL Plant

Enhanced oil recovery would have to be viewed as the most viable and technologically mature CO₂ sequestration technology. The injection of CO₂ miscible gas for EOR—a demonstrated technology—is currently being used in fields in the contiguous United States. The viability and efficiency of CO₂ sequestration in these reservoirs after the remaining oil has been produced is currently being evaluated in several pilot studies (see Chapter 3 of this report). Further evaluation of the economics of this sequestration option require input from the oil companies operating on the North Slope and identification of specific fields targeted for CO₂ EOR and subsequent sequestration.

Recovery of Methane from North Slope Gas Hydrate Deposits

Gas Hydrates

Gas hydrate is a *clathrate*, an unusual type of chemical substance in which a cage of one type of molecule encloses a molecule of another without chemical bonding between the two. In the case of gas hydrate, the cage is formed by ice; the entrapped molecule is hydrocarbon gas (usually methane; Figure 1.3).



Figure 1.3. Schematic of a gas hydrate molecule. Encasing lattice is water ice; enclosed molecule is methane (from <http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates>).

Methane hydrates form and are stable under a combination of moderate pressure and low temperature conditions (Figure 1.4). Methane hydrate is found naturally in arctic and deep marine sediments and manufactured (inadvertently) in natural gas pipelines (Figure 1.5).

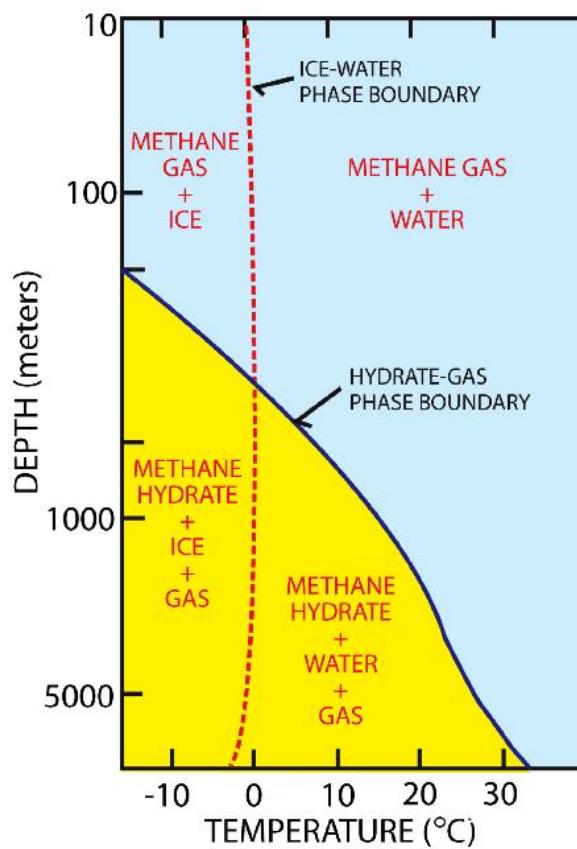


Figure 1.4. Stability of methane hydrate, methane gas, water, and ice with respect to temperature and depth (from Collett et al., 2008).

Gas Hydrate Stability

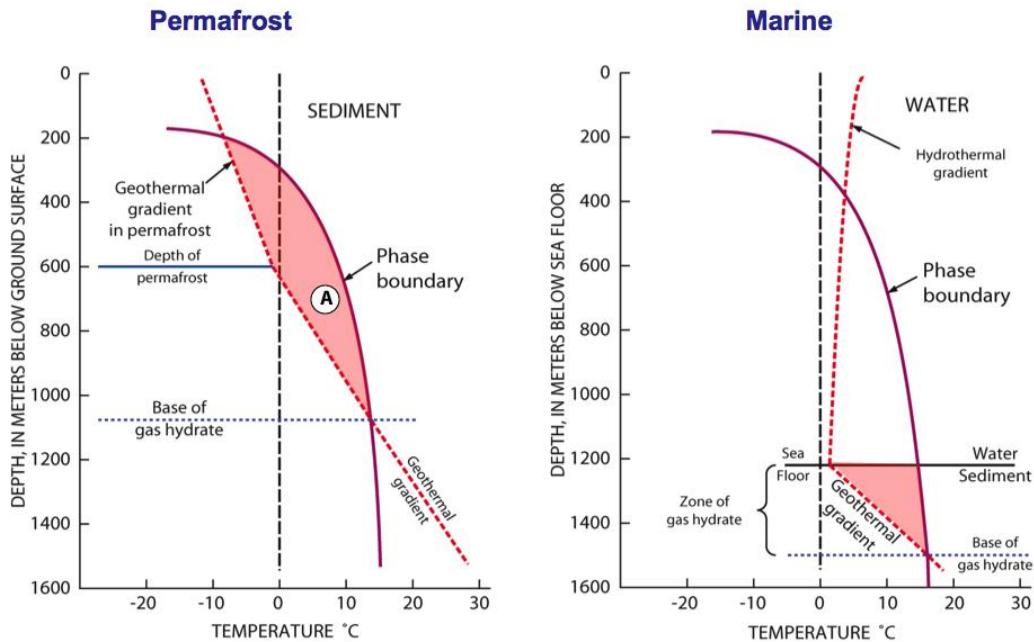


Figure 1.5. Stability zone (in red) of methane hydrate in permafrost vs. marine conditions (from Collett et al., 2008). Point A is a hypothetical gas hydrate accumulation, as discussed in text.

Production of Gas Hydrates

In order for methane to be produced from methane hydrate, the clathrate structure must be broken down. Although no gas hydrates have been commercially produced, there are four proposed methods (Hyndman and Dallimore, 2001). Regardless of how this dissociation is accomplished, the process is an endothermic reaction and requires a source of heat.

The methods are

1. Add heat and raise the temperature of the gas hydrate. In Figure 1.5, this would have the effect of moving Point A to the right and out of the methane hydrate-stability field, resulting in a breakdown of the clathrate structure and release of methane. This approach has been tested on Mallik well, a methane hydrate test well in Canada (Dallimore and Collett, 2005).
2. Depressurize methane hydrate accumulation by removing free gas that has accumulated below the gas hydrate. This would effectively move Point A in Figure 1.5 vertically, resulting in dissociation of the clathrate. Because the reaction

is endothermic, there still needs to be a source of heat. Heat could be provided by the surrounding rocks (Singh, 2008). This mode of hydrate dissociation is thought to occur in the Barrow gas fields on the North Slope of Alaska, resulting in recharge of the gas reservoir (Singh, 2008).

3. Add antifreeze such as methanol. This effectively moves the stability curve to the left so that Point A lies outside of the gas hydrate zone (Figure 1.5). This is not considered a viable field-wide production strategy (Singh, 2008).
4. Replace the methane in the clathrate with CO₂. Laboratory and theoretical studies suggest that CO₂ forms a more stable clathrate than methane, resulting in a spontaneous dissociation of the methane clathrate to a CO₂ clathrate (Graue et al. 2006; Stevens et al. 2008). Dissociation of the methane hydrate and reformation of the CO₂ hydrate occurs rapidly, with no apparent release of water or destruction of the reservoir pore structure. In the process, one molecule of CO₂ is sequestered for each molecule of methane released.

A ConocoPhillips pilot project funded by the DOE is currently underway exploring the technological feasibility of this option. The project is still in the early phases (http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/projects/DOEProjects/MH_06553HydrateProdTrial.html). See Chapter 3 for more discussion of the pilot project.

Distribution of Gas Hydrates on the North Slope of Alaska

The North Slope of Alaska is believed to have a significant amount of onshore methane hydrate. A recent assessment by the U.S. Geological Survey (USGS) (Collett et al., 2008) divided the distribution and volume of projected methane hydrate accumulations into three assessment units based on reservoir age (Figures 1.6, 1.7, and 1.8).

Assessment of CO₂ Sequestration Options and Other Environmental Impacts
Related to the Proposed Coal-to-Liquids Plant at Eielson Air Force Base

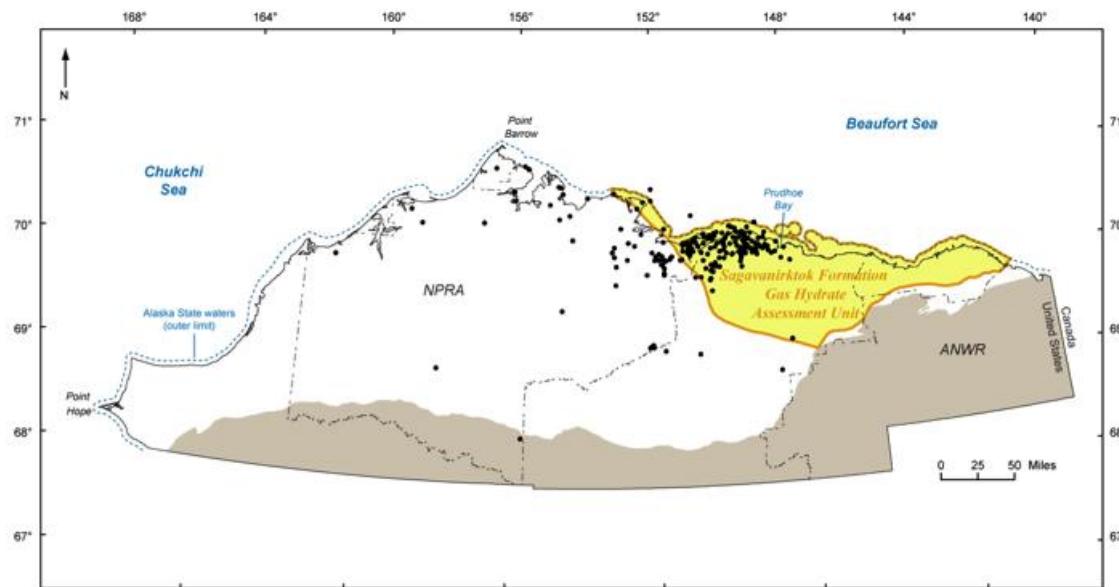


Figure 1.6. Postulated extent of the Sagavanirktok Formation gas hydrate accumulations (from Collett et al., 2008).

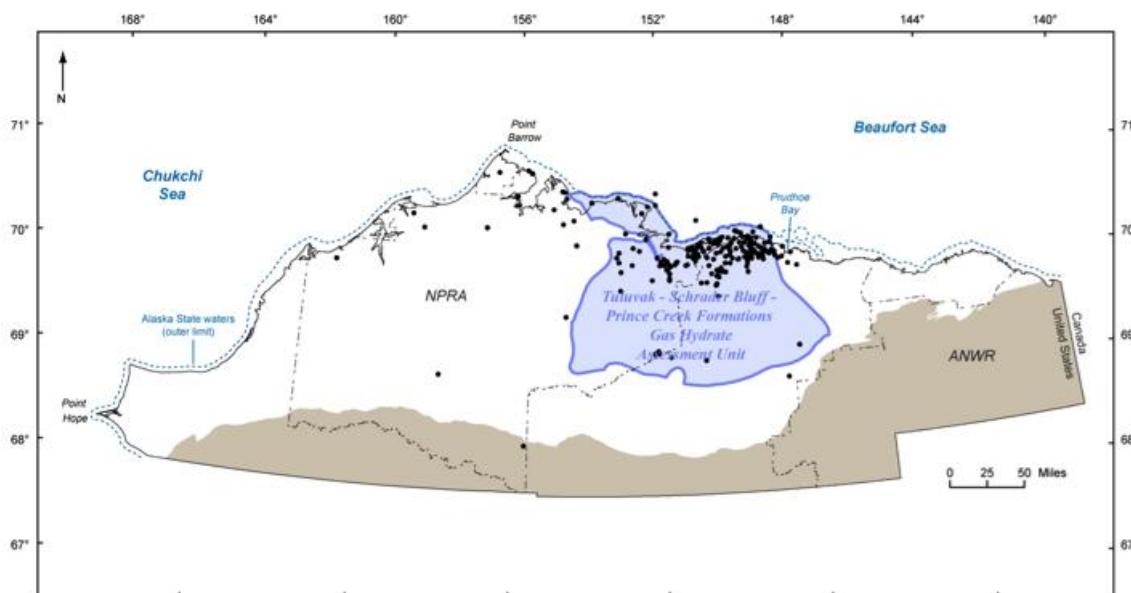


Figure 1.7. Postulated extent of the Tuluvak-Schrader Bluff-Prince Creek Formations gas hydrate accumulations (from Collett et al., 2008).

Assessment of CO₂ Sequestration Options and Other Environmental Impacts
Related to the Proposed Coal-to-Liquids Plant at Eielson Air Force Base

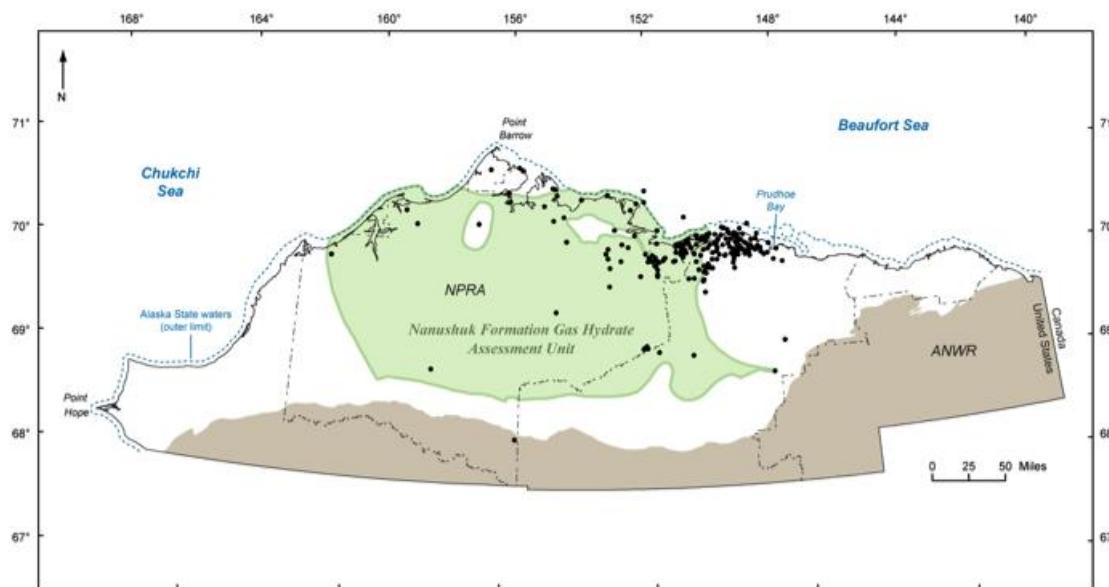


Figure 1.8. Postulated extent of the Nanushuk Formation gas hydrate accumulations (from Collett et al., 2008).

The USGS assessment evaluated these three units in terms of potential methane hydrates in place (Table 1.3). Since one CO₂ molecule would be stored for every methane molecule produced, this assessment suggests that, for the mean amount of estimated methane resource, over 85 Tcf of CO₂ could be sequestered using this approach.

Table 1.3. USGS Alaska North Slope assessment of undiscovered gas resources in methane hydrates (from Collett et al., 2008).

Total Petroleum System and Assessment Unit	Field Type	Total Undiscovered Resources							
		Gas (BCFG)				NGL (MMBNGL)			
		F95	F50	F5	Mean	F95	F50	F5	Mean
Northern Alaska Gas Hydrate TPS									
Sagavanirktok Formation Gas Hydrate AU	Gas	6,285	19,490	37,791	20,567	0	0	0	0
Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU	Gas	8,173	26,532	51,814	28,003	0	0	0	0
Nanushuk Formation Gas Hydrate AU	Gas	10,775	35,008	68,226	36,857	0	0	0	0
Total Undiscovered Resources		25,233	81,030	157,831	85,427	0	0	0	0

Note: Results shown are fully risked estimates. F95 represents a 95% chance of at least that amount of resource; BCFG = billion cubic feet of gas; MMBNG= million barrels of natural gas liquids; NGL = Natural gas liquids; AU = assessment unit.

Viability with Respect to the Eielson CTL Plant

While the production of gas hydrates is an intriguing possibility, this technology has to be considered as still in the experimental stage and not a viable sequestration option for CO₂ produced by the Eielson CTL facility. The effectiveness of the approach for significant and long-term CO₂ storage has not been evaluated, and the necessary technology has not been developed to the point of commercial viability. However, the infrastructure for transport of CO₂ to the North Slope of Alaska for this purpose is the same as that for EOR. If the DOE/ConocoPhillips test project determines that this is a technologically feasible method of sequestering CO₂, this approach could provide a market for CO₂ produced by the Eielson plant.

Coalbed Methane Production and/or Injection into Deep Coal Seams in Nenana Basin Coalfields

Level of Demonstrated Technology

Significant quantities of methane gas are commonly stored in coal as molecules adsorbed onto the pore and fracture surfaces within the coal. This gas can be produced by depressurizing the coal, usually by removal of the water normally present in the pores and fractures. An alternative approach is to inject CO₂ into the coal. Carbon dioxide more readily adsorbs to coal than methane, thus displacing the methane. The CO₂ remains in the coal, allowing the methane to be produced (www.fossil.energy.gov). The advantage of this approach is twofold, as a valuable source of energy is produced and CO₂ is sequestered. In addition, a previously unusable resource—deep unmineable coal seams—can be utilized.

While this technique is being demonstrated in several field tests, the technology is still in the development and testing phase.

Distribution of Coal in Interior Alaska

The Nenana Basin contains substantive coal, which is exposed along the south side of the basin (Figure 1.9). The Nenana coalfield at the western end of the belt is currently being mined at the Usibelli Coal Mine and is actually the proposed feedstock for the Eielson CTL plant. The Jarvis Creek coalfield and other small coalfields that occur in discontinuous exposures along the southwestern edge of the Nenana Basin are the eastern extension of the Nenana coalfield that has been segregated by erosion.

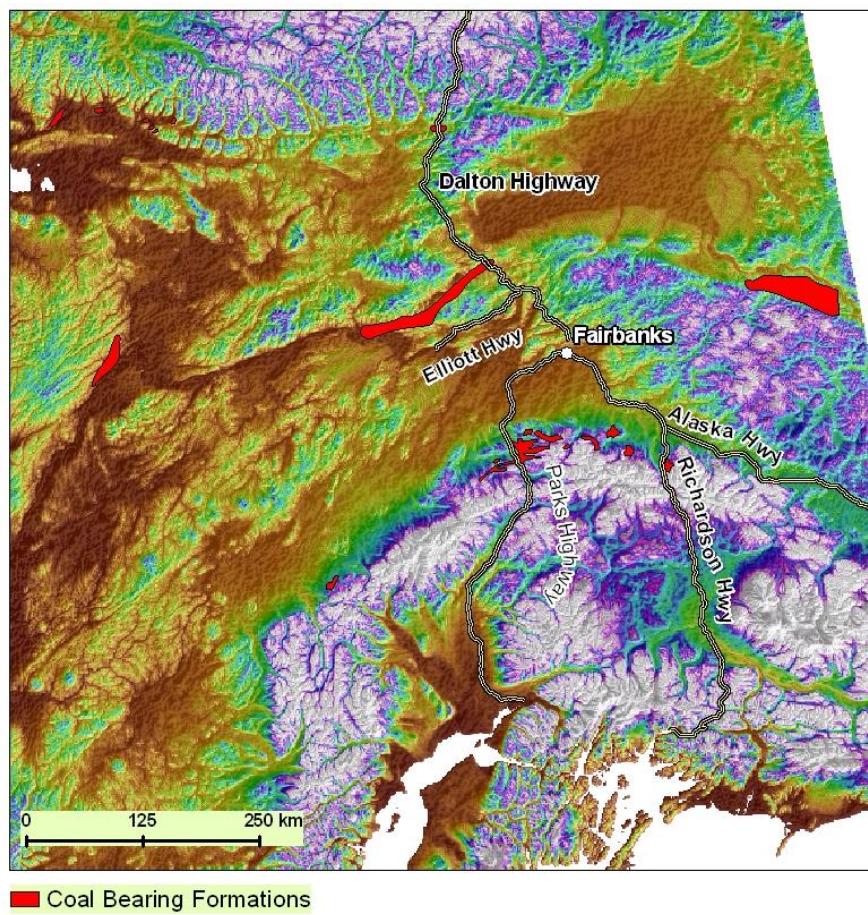


Figure 1.9. Surface distribution of coal-bearing rocks in Interior Alaska (data from Wilson et al., 1998; GIS data compilation by S. Panda).

The general geology of the Nenana coals is described by Wahrhaftig (1969). The Nenana coalfield alone, which extends in an east-west direction for 200 kilometers along the north side of the Denali Fault, covers approximately 10,000 square kilometers. Measured geologic sections near the Usibelli Coal Mine as well as exposures in the surface mining operation indicate that the coal-bearing sequence includes approximately 600 meters of upward-fining clastic sediments and coal. Thus, the estimated volume of sediments in the coalfield is 6,000 cubic kilometers.

The coal-bearing sequence is divided into five formations, from oldest to youngest: Healy Creek Formation, Sanctuary Shale, Suntrana Creek Formation, Lignite Creek Formation, and Grubstake Formation. The basal conglomerate of the Healy Creek Formation unconformably overlies the Yukon Tanana Schist of late Precambrian to Lower Paleozoic age. The coal-bearing sequence ranges in age from Miocene to Pliocene and is unconformably overlain by the Nenana Gravel of Pliocene and Pleistocene age.

The coal-bearing sequence has been subjected to major normal, thrust, and strike-slip faulting. The region is tectonically active, and magnitude 7.0 earthquakes have been recorded within a few kilometers of the Usibelli Coal Mine.

The poorly lithified, coarse clastic sediments have moderate to high porosity and permeability. Shales below the major coal seams range in thickness from a meter to more than 30 meters. The sufficiency of these shale units to provide an impervious layer for CO₂ storage is uncertain, even in the active mine areas, let alone in areas without subsurface sampling.

The Jarvis Creek coalfield and other smaller coalfields are located approximately 125 kilometers southeast of Eielson Air Force Base (AFB). The general geology of the Jarvis Creek coalfield, described by Wahrhaftig and Hickox (1955), is probably representative of other small coalfields that are less well documented. The Jarvis Creek coalfield includes an area of 25 square kilometers, and its estimated depth is 600 meters or less.

Estimated Storage Capacity

The storage capacity of the Nenana coalfield is potentially very large relative to the expected volume of CO₂ that would be generated by the CTL plant. The capacity of the Jarvis Creek coalfield is much smaller, but is likely to be sufficient even if the volume is restricted to depths below 300 meters. In either case, not enough information is publicly available on the subsurface distribution of the Nenana coals to make a quantitative estimate.

Relative Economic Cost

The Usibelli Coal Mine is approximately 125 kilometers southwest of Eielson AFB. The eastern portion of the exposed belt of Nenana coals is approximately 125 kilometers southeast of Eielson AFB and is within the Donnelly Training area and the Blair Lakes Bombing Range. The existing infrastructure at Usibelli Coal Mine suggests that the southwestern end of the Nenana coal belt would be a potential target for CO₂ sequestration by coalbed methane production from deep coal seams.

Injection into Deep Clastic Basins and/or Saline Aquifers

Level of Demonstrated Technology

Deep clastic basins can serve as CO₂ sequestration sinks in two ways: CO₂ can be injected into depleted oil and gas fields, or into saline aquifers that have no hydrocarbons but otherwise exhibit the same trapping capabilities as those seen in conventional oil and gas fields. The major requirements in both cases are as follows:

1. Reservoir rocks. Reservoir rocks have sufficient natural storage capacity (porosity) to provide storage volume for CO₂. In addition to porosity, good reservoir rocks need adequate permeability so that the CO₂ can move away from the injection site into other parts of the reservoir.
2. Sealing rocks. Seals, which have no porosity and permeability, provide permeability barriers so that the CO₂ does not leak from the reservoir rock into the overlying sedimentary rocks and potentially escape to the surface.
3. Trap. This is a geometric configuration of reservoir and seal so that the CO₂ remains isolated in one place and does not disperse laterally, potentially migrating to the surface. Examples of such configurations are shown in Figure 1.10.

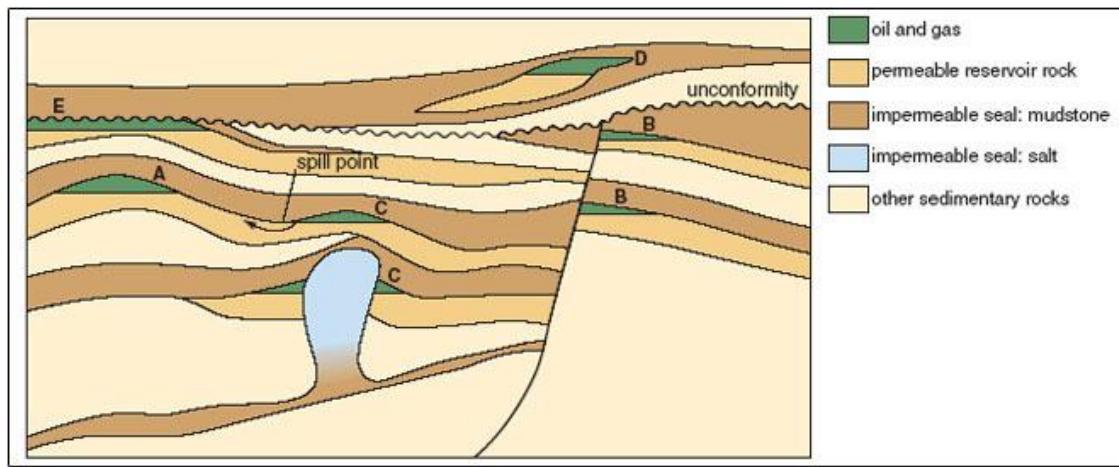


Figure 1.10. Major categories of structural and unconformity-related traps. A. Anticline; B. Fault; C. Anticline and truncations related to salt domes; D. Stratigraphic pinchouts; E. Truncation by unconformities. Types A, B, D, and E might be expected to occur in Interior Alaska basins (from openlearn.open.ac.uk).

Oil and gas production technology would be used to sequester CO₂ in these types of reservoirs. The main concern in CO₂ sequestration is subsequent monitoring of the CO₂ behavior to assure that, indeed, it is being sequestered, not migrating.

Distribution of Sedimentary Basins in Interior Alaska

Two major sedimentary basins within 200 kilometers of Eielson AFB are candidates for CO₂ sequestration: the Nenana Basin and the Yukon Flats Basin (Figure 1.11). Both basins, which are middle to late Tertiary in age, have an estimated depth of 4,000–5,000 meters and contain terrestrial clastic sediments and coal. Both basins are fault-bounded depressions generally associated with regional scale strike-slip fault systems. The

stratigraphy is that of repeated upward-fining sequences of basal conglomerate, sandstone, siltstone, shale, and coal. The sediments are poorly lithified, and the coal ranges in rank from lignite to subbituminous grade. The conglomerate and sandstone units have moderate to high porosity and permeability. Volumetrically, the clastic sediments exceed the volumes of coal by factors of 5 to 6 times. The shale units underlying the coal seams range in thickness from a few meters to 30 meters in the drilled sequences and measured sections and in the coal mining areas.

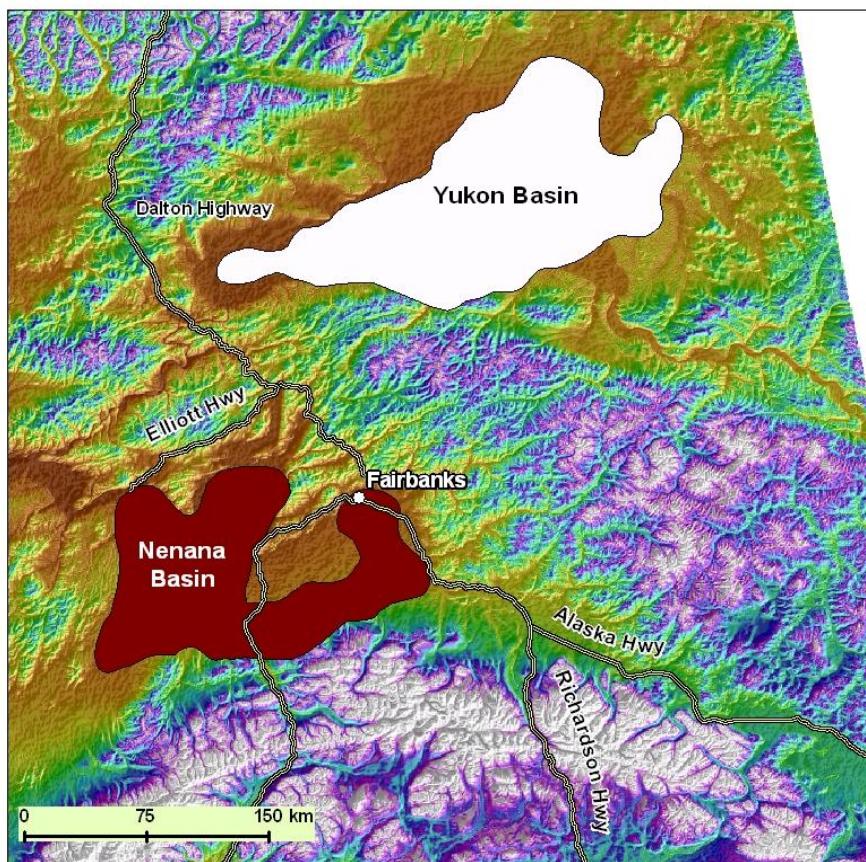


Figure 1.11. Location of the Nenana and Yukon Flats basins in Interior Alaska (GIS data compilation by S. Panda).

Estimated CO₂ Sequestration Capacity

The volume of CO₂ sequestered in a clastic sedimentary sequence is a function of the volume of sediments, porosity, and depth of injection. The first two parameters are self-explanatory, but depth of injection must be clarified. The density of CO₂ increases rapidly from 0.2 at 1,000 psi (pounds per square inch) to 0.6 at approximately 1,400 psi. It is assumed that the pressure at any depth of injection is equivalent to the lithostatic load of the overlying column of rock. Thus, the volume of sequestered gas increases threefold

with an increase in lithostatic load of 400 psi. Assuming a density of 2.3 for the sedimentary rock column, a depth of 420 meters would be required to produce a lithostatic load of 1,400 psi and a CO₂ density of 0.6.

Assuming a porosity of the clastic sedimentary rocks in both basins of 0.1 and 0.05 can allow estimation of the volume of sedimentary rock necessary to sequester CO₂ from the two 40,000 barrel per day CTL plants over a 30-year period (at the assumed depth of 420 meters). For the 40,000 barrel per day plant operating without natural gas, volumes are 5.2 ($314,308,800/(0.1 \times 0.6)$) and 10.4 ($314,308,800/(0.05 \times 0.6)$) cubic kilometers, respectively. For the 40,000 barrel per day plant operating with natural gas, the volumes are 1.2 ($73,058,400/(0.1 \times 0.6)$) and 2.4 ($73,058,400/(0.05 \times 0.6)$) cubic kilometers, respectively. Thus, even a small trap in either basin could potentially accommodate the volume of CO₂ generated from the proposed CTL plant under certain constraints.

Accelerated Weathering of Ultramafic Rocks

Level of Demonstrated Technology

Berner (1990) has demonstrated that CO₂ concentrations in the atmosphere have varied considerably over the past 600 million years of geologic time, from a low of 250 ppm (parts per million) in the early part of the twentieth century to 2,000% of that in the beginning of the evolution of complex life-forms in the early Paleozoic. Atmospheric CO₂ concentrations are moderated by the weathering of rocks and the deposition of carbonate sedimentary rocks. Sedimentary carbonate rocks are composed dominantly of calcium and magnesium carbonates (calcite, dolomite, and magnesite), and are the major sink of carbon in the earth's crust. The average crustal abundance of carbon is 0.09%, and carbonate rocks account for 99% of this carbon, with coal, petroleum, natural gas, life-forms, CO₂ dissolved in water, and atmospheric CO₂ constituting the remaining 1%. Engineered systems for the sequestration of anthropogenic CO₂ are most likely to be technically successful and compatible with the environment if they mimic the natural system of sequestration.

Goff and Lackner (1998) outlined the potential for permanent storage or sequestration of large volumes of CO₂ as the carbonate mineral magnesite (MgCO₃) by reacting CO₂ with ultramafic rocks. Ultramafic rocks are composed of iron and magnesium-rich minerals that formed at high temperatures and pressures and at low fugacities of CO₂ and water vapor. At atmospheric temperatures and pressures, these minerals are unstable and naturally react through chemical weathering processes to form hydrous carbonate minerals (Wilson et al., 2009). Goff and Lackner (1998) estimate that, theoretically, one cubic kilometer of ultramafic rock could sequester 1 billion tons of CO₂. Wilson et al. (2009) demonstrate that such large volumes of atmospheric CO₂ are currently being sequestered in the ultramafic mine tailings at two former asbestos mines in northern

Canada. This sequestration is occurring under subarctic conditions similar to those in Interior Alaska.

Under ambient temperatures and partial pressures of CO₂, the reaction rates for the conversion of iron, magnesium, and calcium aluminum silicates to carbonates is measured in decades; however, at 150–160°C, the reactions can occur in hours (O'Connor et al., 2000). At the flue gas temperatures of CTL plants, the reactions are expected to achieve high rates of conversion in minutes.

Distribution of Ultramafic Rocks in Interior Alaska

Ultramafic rock units located in Interior Alaska (from Wilson et al., 1998) are as follows:

1. MzZum – Ultramafic and mafic rocks undivided of Mesozoic, Paleozoic, and or late Proterozoic age in the Big Delta, Livengood, and Tanana Quadrangles.
2. JPsu – Ultramafic and associated rocks of Jurassic and/or Permian age in the Fairbanks, Big Delta, and Circle Quadrangles.
3. JTrtmu – Mafic and ultramafic rocks associated with the Permian age Rampart Group in the Tanana and Livengood Quadrangles.
4. Mzum, Mlu, Kmum – Ultramafic and associated rocks of Mesozoic age along Denali Fault in the Healy and Mount Hayes Quadrangles.

Patton et al. (1994) have described the general geology of the ultramafic complexes in Alaska (Figure 1.12). The mantle-derived rocks are found along or near large transform or thrust faults. The rocks range from pyroxenites to peridotites and dunites, and are usually partially altered to serpentinites. They have widespread aerial distribution including Interior Alaska. The ultramafic complexes may range from one to several hundred square kilometers in outcrop. In Interior Alaska, the largest two outcrops (unit MzZum) occur north of Fairbanks in the Livengood area and encompass approximately 100 square kilometers each. The total thickness of these occurrences probably exceeds 300 meters; thus, the total volume of each is estimated at 30 cubic kilometers. The three smallest known ultramafic occurrences in Interior Alaska are located in the Tanana Flats Training Area, adjacent to Eielson AFB (unit JPsu). Each of the 3 covers approximately 1.5 square kilometers and, based on local relief, are estimated to be at least 300 meters thick. Thus, the total volume of the 3 bodies is estimated at 1.5 cubic kilometers. The other ultramafic complexes (units JTrsu, Mzum, Mlu, and Kmum) are more remotely located relative to potential sites for the CTL plant. These occurrences are intermediate in size when compared with the outcrops just described.

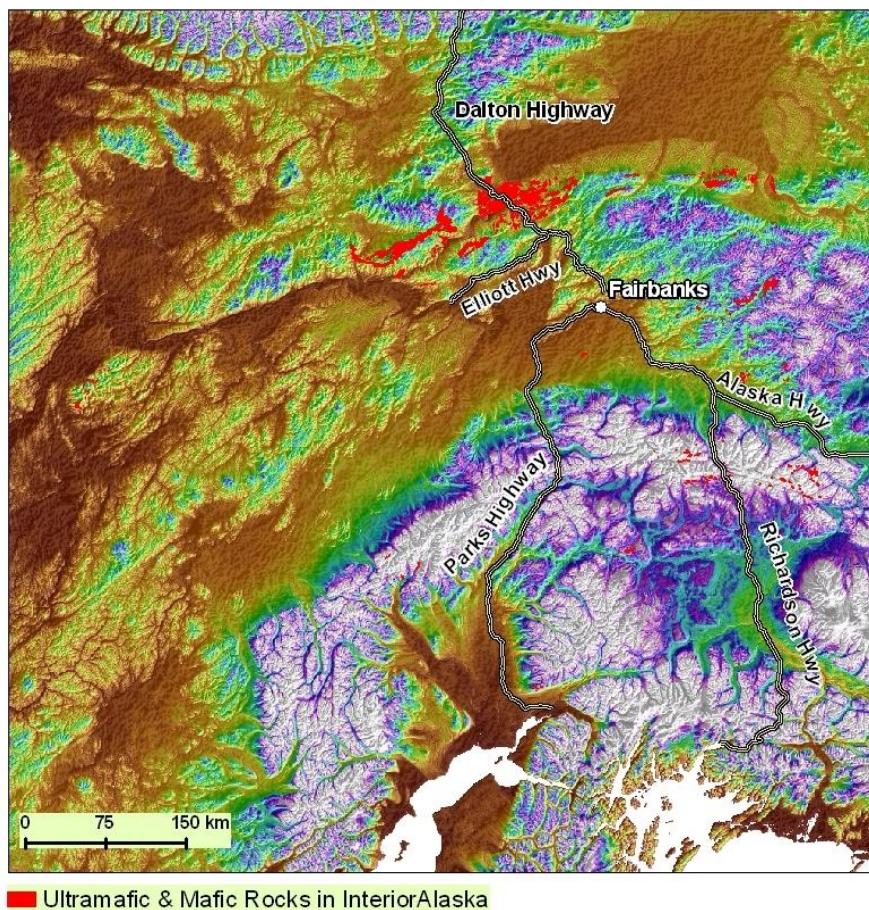


Figure 1.12. Surface distribution of ultramafic and mafic rocks in Interior Alaska (data from Wilson et al., 1998; GIS data compilation by S. Panda).

Estimated CO₂ Sequestration Capacity

The estimated storage capacity of ultramafic rocks within the bounds of military training areas adjacent to Eielson AFB is 1.5 billion tons (1.0 billion tons per km³ × 1.5 km³). Thus, storage capacity would greatly exceed the total production of CO₂ from the proposed 40,000 barrel/day CTL plant for an expected 30-year period (314,308,800 tonnes without natural gas and 73,058,400 tonnes with natural gas).

Relative Economic Cost

Accelerated weathering of ultramafic rocks would be a relatively low cost of CO₂ sequestration at a CTL plant site in Interior Alaska. Currently, the Fort Knox Gold Mine, a large-scale open-pit gold mine near Fairbanks is mining and processing the ore for less than \$10 per ton. It is expected that a similar cost would occur for mining and processing the ultramafic rocks in the Tanana Flats Training Area. With the current tax credit of \$20 per ton for CO₂ sequestration in non-petroleum geologic environments, the tax credits

exceed the expected costs. The capture of some of the exothermic heat of reaction either for use in the CTL plant or for locally distributed space heating could provide an additional economic incentive for this process.

Accelerated Weathering of Limestone

Level of Demonstrated Technology

Rau et al. (2007) and Langer et al. (2009) have outlined the science and methodology for employing accelerated weathering of limestone (AWL) to remove CO₂ from flue gas streams of fossil fuel power plants and from exhaust streams of cement kilns. The simple technology consists of spraying emission streams with water, thus producing carbonic acid from the contained CO₂ and then neutralizing the carbonic acid with finely crushed limestone. This chemical weathering process is the same that occurs in nature to form “karst terranes” in warm and wet climates where the underlying bedrock is limestone and/or dolomite (calcium and/or calcium-magnesium carbonate). The resulting bicarbonate and calcium ions are then transported to the marine environment, where the ions precipitate directly from seawater or precipitate via biologic activity to form more limestone or dolomite.

Distribution of Limestones in Interior Alaska

Carbonate rock units located in Interior Alaska (from Wilson et al., 1998) are shown in Figure 1.13 and listed as follows:

1. Ds – Schwatka Limestone unit (Middle to Early Devonian) in the Livengood and Circle Quadrangles.
2. DS_{lc} – Lost Creek unit (Devonian and Silurian) in the Livengood Quadrangle.
3. DS_l – Limestone (Late Devonian to Middle Silurian) in the Circle, Kantishna River, Livengood, and Tanana Quadrangles.
4. DSt – Tolovana Limestone (Middle Devonian to Silurian) in the Livengood and Circle Quadrangles.

Devonian and Silurian age limestone is relatively abundant in Interior Alaska, particularly in the Livengood Quadrangle, which extends from just north of Fairbanks to the Livengood area approximately 70 road miles to the north. Outcrops of Tolovana Limestone at 38 mile on the Elliot Highway (48 miles north of Fairbanks) were examined by Warfield (1973) as a potential source material for Portland cement manufacture. Sanusi (1983) reported on the calcium carbonate equivalent (CCE) of these rocks. The high-purity

limestone forms two large hills along the east side of the highway. Based on the geologic mapping of Bundtzen (1983), a resource estimate for these outcrops is 1.6 billion tons at an average CCE of 95%.

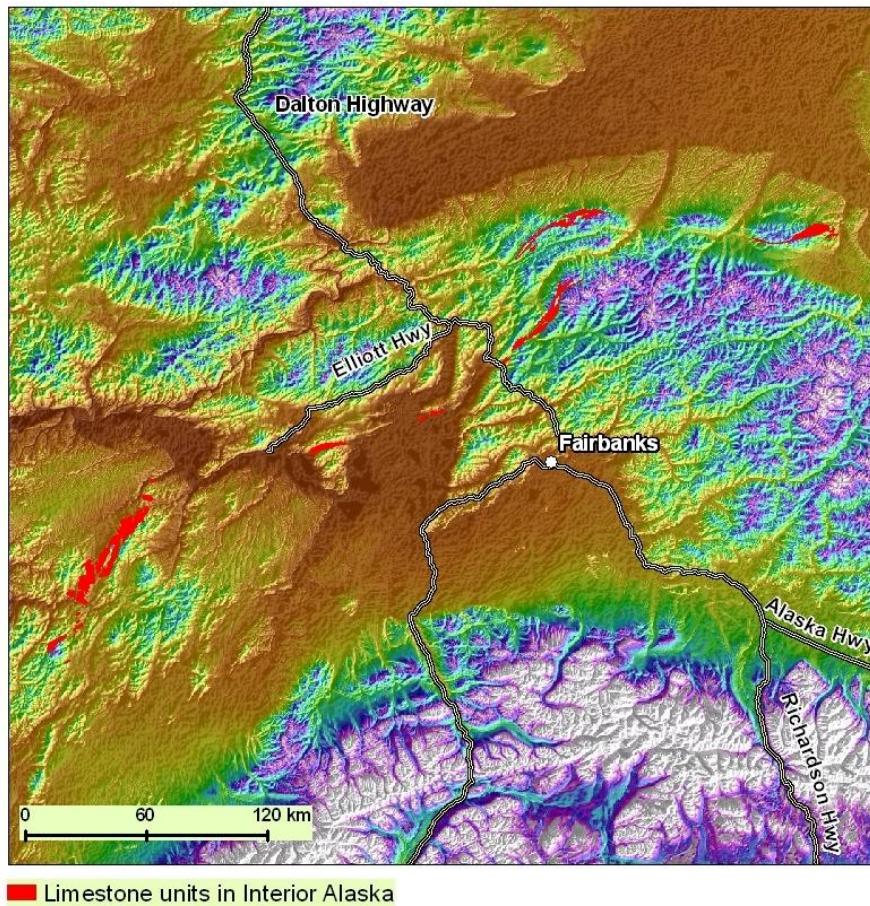


Figure 1.13. Surface distribution of limestones in Interior Alaska (data from Wilson et al., 1998; GIS data compilation by S. Panda).

Estimated CO₂ Sequestration Capacity

Rau et al. (2007) estimate, based on stoichiometry, that 2.3 tonnes of pure calcium carbonate are required to sequester 1.0 tonne of CO₂. The resource, therefore, has the potential to permanently store approximately 700 million tonnes of gas. This capacity is more than twice the expected production of CO₂ from the CTL plant, assuming the worst case for CO₂ production from the coal-only alternative.

Relative Economic Cost

A potential leasehold operator of the Tolovana Limestone deposit at Globe Creek provided an estimate for crushed limestone delivered by truck to Fox, Alaska (10 miles north of Fairbanks). Assuming the construction of a short rail spur from Fox to Fairbanks

by the Alaska Railroad Corporation and a \$0.06/tonne-mile cost of rail transport, crushed limestone could be delivered to Eielson AFB for approximately \$20 per tonne. Adding in the cost of unloading the material, pumping water and CO₂ into vats of limestone, and pumping the solutions into a major drainage basin, the estimated cost of the method is approximately \$50/tonne of CO₂ sequestered. This assumes that the process water that is saturated with calcium ions and has high bicarbonate concentrations could be discharged into the Tanana River near Eielson AFB. Since rivers in karst terranes are saturated with calcium and have high bicarbonate concentrations, regulatory agencies may find the discharge of process water into the river acceptable. This issue is critical for this technology.

Injection into Mafic Volcanic Rocks

Level of Demonstrated Technology

The permanent sequestration of CO₂ by the reaction of a relatively concentrated gas stream with the calcium, iron, and magnesium in basalts (McGrail et al., 2006) and ultramafic rocks (Goff and Lackner, 1998) is a technology that has progressed from laboratory stage to field demonstration stage. Wilson et al. (2009) have documented the significance of natural fixation of CO₂ in the mine tailings of ultramafic-hosted ore deposits and have postulated similar potential for fixation in gabbroic-hosted Cu-Ni-Co (copper-nickel-cobalt) deposits, such as those in the Nikolai Greenstone and Rampart Group Volcanics of Interior Alaska.

Metz (2008) presented a conceptual design for the direct injection of total flue-gas streams from stationary power plants into large underground cavities in mafic volcanic rocks. The benefits of this technology over segregation of CO₂ and injection of concentrated gas into secondary pore spaces are summarized as follows:

1. Avoidance of the capital and operating costs of gas separation,
2. Ability to use flue gas “waste” heat to enhance carbonation reaction rates,
3. Utilization of oxygen and nitrogen in the flue gas stream as carriers to transfer heat of the exothermic reactions back to the surface,
4. Potential precipitation of other deleterious materials in the flue gas stream such as mercury, arsenic, and sulfur along with the carbonate minerals in the subsurface,
5. Greater abundance of basaltic rocks than ultramafic rocks, with the potential to store large volumes of CO₂ in large areas of Interior Alaska, and

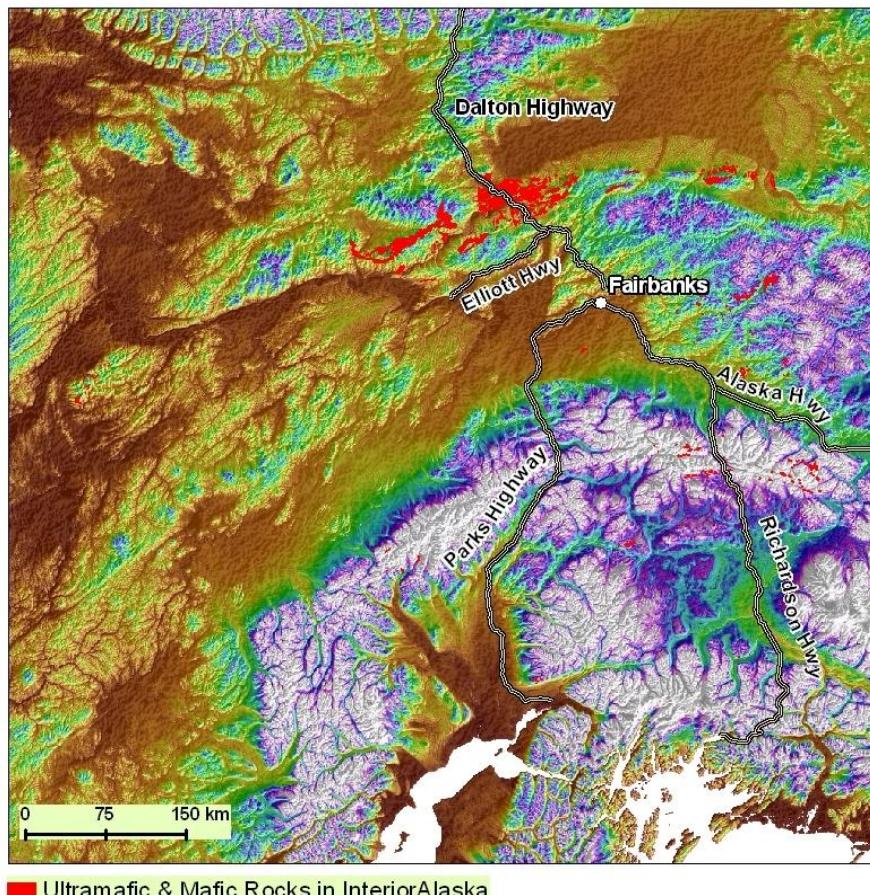
6. Lowering of the pH of connate fluids in mafic rocks by CO₂ injection, which could result in the leaching and recovery of metals from these rocks that are often enriched in Cu-Ni-Co-PGE.

Thus, there is significant potential for the development of a carbon capture and sequestration technology that may actually have a positive economic impact rather than one that increases the cost of fossil fuel conversion and power generation.

Distribution of Mafic Rocks in Interior Alaska

Permian and Tertiary Mafic Volcanic units located in Interior Alaska (from Wilson et al., 1998) are shown in Figure 1.14 and listed as follows:

1. Tb – Basalt (early Tertiary) in the Fairbanks, Healy, and Livengood Quadrangles.
2. Tcv – Volcanic rocks of the Cantwell Formation (Tertiary) in the Healy Quadrangle.
3. Kmum –Mafic and ultramafic rocks (Cretaceous?) associated with strike-slip and thrust faults in the Big Delta, Mt. Hayes, and Tanana Quadrangles.
4. JTRtmu – Mafic and ultramafic rocks (Jurassic? to Triassic and Permian) in the Livengood and Tanana Quadrangles.
5. TRn – Nikolai Greenstone and related rocks (late and/or Middle Triassic) in the Healy and Livengood Quadrangles.



■ Ultramafic & Mafic Rocks in Interior Alaska

Figure 1.14. Surface distribution of ultramafic and mafic rocks in Interior Alaska (data from Wilson et al., 1998; GIS data compilation by S. Panda).

The Rampart Group Volcanics (Mertie, 1937), which extend from the village of Rampart on the Yukon River upstream for 250 kilometers to the Yukon River Bridge on the Dalton Highway, are the largest accumulation of mafic volcanic rocks within 200 kilometers of Eielson AFB. The Rampart Group contains basalt, pillow basalt, phyllite, argillite, slate, volcaniclastic rocks, arkose, conglomerate, Permian limestone, and radiolarian chert. Noted during recent field investigations were minor oil shale (tasmanite ?) associated with the chert sequences and bituminous coal associated with the arkosic sandstones and conglomerates near the Yukon River. Gabbroic dikes and sills along with serpentinized ultramafic rocks intrude the basaltic rocks. The Rampart Volcanics outcrop over an area of 12,000 square kilometers. The total thickness of the volcanic sequence is unknown, but must exceed several kilometers due to the large range composition of the sedimentary sequences and the vertical relief along the Yukon River.

The Nikolai Greenstone that extends from Paxson westward for nearly 150 kilometers on the south flank of the Alaska Range is also a major accumulation of mafic rocks. The unit

is composed of massive sub-aerial basalt flows, pillow basalts, volcaniclastic rocks, and deep-water sediments including argillite and chert. The volcanic units are intruded by gabbroic dikes and sills. The estimated thickness of the Nikolai Greenstone exceeds 4,000 meters. The mafic volcanic sequence outcrops over an area of at least 7,500 square kilometers.

Estimated Storage Capacity

The distribution of mafic rocks in the subsurface is not well constrained at this time, but it is likely that there is high storage capacity relative to the volume of CO₂ that the CTL plant is expected to generate.

Relative Economic Cost

Other than the North Slope oil fields, the Rampart Group Volcanics and the Nikolai Greenstone are the most distal sites for CO₂ sequestration that were considered in this investigation. Relatively long distances for pipeline transport, relative preliminary status of the technology, and the potentially high cost of operations in relatively remote areas will make this method of sequestration the most costly in comparison with other alternatives that have been discussed.

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CHAPTER 2

Options for Biological Sequestration and Biomass Feedstock Production

by Amanda Byrd, Meriam Karlsson, and Dennis Witmer

Abstract

The use of biomass to mitigate CO₂ emissions from the proposed CTL plant in Fairbanks has been analyzed, with the following observations:

- Federal law requires that the life cycle emissions of any synthetic fuels purchased by the government be less than that of the conventional fuels they replace, which requires mitigation of all CO₂ released from the proposed plant.
- Using biomass as feedstock is a way of reducing the greenhouse gas footprint of a CTL plant. On a mass basis, one ton of coal input results in one ton of CO₂ produced, so biomass needs to be mixed in at a rate approximately equal to the CO₂ released (1.14 million tons per year for the lowest case).
- Local growth rates for wild willow plants are approximately 1 ton per acre per year.
- Local production of biomass would need to be about 1.14 million acres—1,781 square miles or a contiguous square 42 miles per side. Not all land is available for this use, however, so the transport distance will be greater than this distance. Growing and harvesting biomass requires the use of heavy equipment, which means that this activity also has a non-zero carbon footprint. There is very little land in the Fairbanks area that could be converted from other uses and re-forested, and the threat of wildfires could release the captured CO₂ in an uncontrolled and unrestricted manner.
- Increasing carbon capture through forest management practices in the Fairbanks area does not seem feasible, given that little land is available for planting trees and that the increased prevalence of wildfires and of permafrost melting may release additional CO₂ into the atmosphere.
- Algae growth also does not seem feasible in the Fairbanks area, as most algae grows only when sunlight is available and when ambient conditions are above 15°C (59°F). These conditions are frequently not met in Fairbanks.
- Growing algae in bioreactors has not yet been shown to be economic, and developing low-temperature facilities or methods that do not require sunlight is still in the research stage.

- Other biological sequestration methods have been identified that may work in other parts of the world, but would require either direct investment in these projects or some form of carbon-credit trading. Either method would increase the product cost from the CTL plant.

Emissions Analysis

A major part of the justification for the coal-to-liquids (CTL) plant proposed for the Fairbanks North Star Borough is that it could provide fuel for the U.S. Air Force base at Eielson. Fuel provided to the Eielson Air Force base would have to meet all federal procurement requirements, including those described in Section 526 of the Energy Independence and Security Act of 2007:

SEC. 526. Procurement and Acquisition of Alternative Fuels

No Federal agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related use, other than for research or testing, unless the contract specifies that the lifecycle greenhouse gas emissions associated with the production and combustion of the fuel supplied under the contract must, on an ongoing basis, be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources.

Life-Cycle Cost Analysis (LCA) is used to calculate the carbon footprint of various human activities (Parliament.uk, 2009), but there is much discussion in the scientific community about the carbon footprint of both fossil fuels and alternatives. Fossil fuels have a larger carbon footprint than the combustion release of these fuels; additional emissions occur during fuel production, refining, and transportation. Estimates on the additional CO₂ emissions vary, with some sources showing as much as a 30% increase due to refining and transportation of petroleum fuels, but these estimates also include emissions in the manufacture of vehicles and the building of roads. The energy penalty for refining hydrocarbon fuels is typically 8–10%, and CO₂ emissions from refineries are approximately 10% of the total emissions from combustion of fossil fuels. Numbers for emissions from refineries in the world vary from 125 to 250 million tons per year (total CO₂ emissions in the world from the combustion of fossil fuels is about 5,700 million tons per year).

Carbon dioxide is also released during the mining and transportation of coal. Mining equipment and diesel engine trains emit CO₂, and some CO₂ is released directly into the atmosphere from mined coal. The exact amount of CO₂ released in these operations depends both on the details of the mining operation and the coal being mined.

The issue of CO₂ emissions from biofuels is even more complicated, because converting land from natural forest or grasslands to agricultural uses disturbs organic materials in the

soils, leading to a net increase of CO₂ in the atmosphere that can only gradually be mitigated by the production of biofuels (Farrell et al., 2006; Science Daily, 2009).

Coal to liquids has the same chemical composition as conventional diesel fuel, so its carbon emissions are the same. The conversion of coal to FT liquids, however, uses energy and releases additional CO₂ (see Figure 2.1). Some of the CO₂ can be separated and sequestered, but a significant amount of CO₂ is still released to the atmosphere. Since the basis of this comparison is a life cycle analysis, it must be noted that conventional fuels have an additional carbon footprint due to emissions during oil production, transportation, and refining. Different researchers have established different values for this by-product greenhouse gas, a value given as an additional 18% by an Argonne study in 2002 (Wang, 2009). However, the mining of coal also releases additional greenhouse gases, including CO₂ emissions from the heavy equipment and electricity used in mining, and from transporting the coal via train from the mine to the plant. Emissions estimates associated with the production of coal vary (McKinnon, 2009; U.S. Department of Energy, 2009)—between 3.5–14%, depending heavily on the distance the coal is shipped. As an estimate for this study, a value of 7.5% was used (based on 3.5% for a mine-mouth efficient plant, plus the estimated CO₂ emissions for transporting the coal 130 miles). Calculating this value gives an additional 730,000 tons of CO₂ per year, a value close to the 600,000 tons of additional CO₂ that the life cycle estimate adds to conventional petroleum-based fuels.

This estimate means that in order for a CTL plant to meet the requirements of the law, all of the CO₂ separated in the plant must be sequestered; but in addition, the CO₂ releases to the atmosphere must be mitigated in some way. This discussion is aimed only at mitigating that portion of the CO₂ released to the atmosphere from the plant, specifically using biological processes to store carbon in biomass.

But how much biomass is needed? If we look at coal consumption of the proposed plant as compared with CO₂ release for Case 1 (Figure 2.1), the coal consumed is 717 tons per hour, while the total CO₂ production is about 730 tons per hour. These figures mean that each ton of coal produces slightly more than a ton of CO₂ (1.018 tons), but a one-to-one replacement of biomass for coal is a reasonable first-order estimate.

Energy content and carbon content of biomass vary greatly with both the source of the biomass and the moisture content. However, on a weight basis, dry biomass has an energy content of about 10,000 Btu per pound, similar to that of dry coal. (Note: Alaskan low-rank coals contain 25–28% moisture, which reduces the heating value of the coal to 7,500–7,800 Btu per pound. Standing trees contain about 50% moisture by weight, but firewood is typically dried to 15–20% moisture before being used [Woodheat.org, 2009]). For this discussion, 1 ton of coal replaced by 1 ton of biomass (suitably dried) is used as an approximation. (Note that the use of biofuels to offset CO₂ gases released to the

atmosphere has become a topic of heated discussion in the scientific community, as growing crops to make fuel consumes fossil energy resources for both fertilizer and the equipment used to grow the crops. Additional impacts are caused in other parts of the world, as forests and grasslands are converted to agricultural uses in Brazil and other countries, with substantial CO₂ released from this disturbance of the natural vegetation (Farrell et al., 2006). It is not clear that corn-based ethanol has any positive impact on global greenhouse gas emissions—and it also is not clear what the unintended consequences would be on emissions from using Alaskan biomass for this proposed project.)

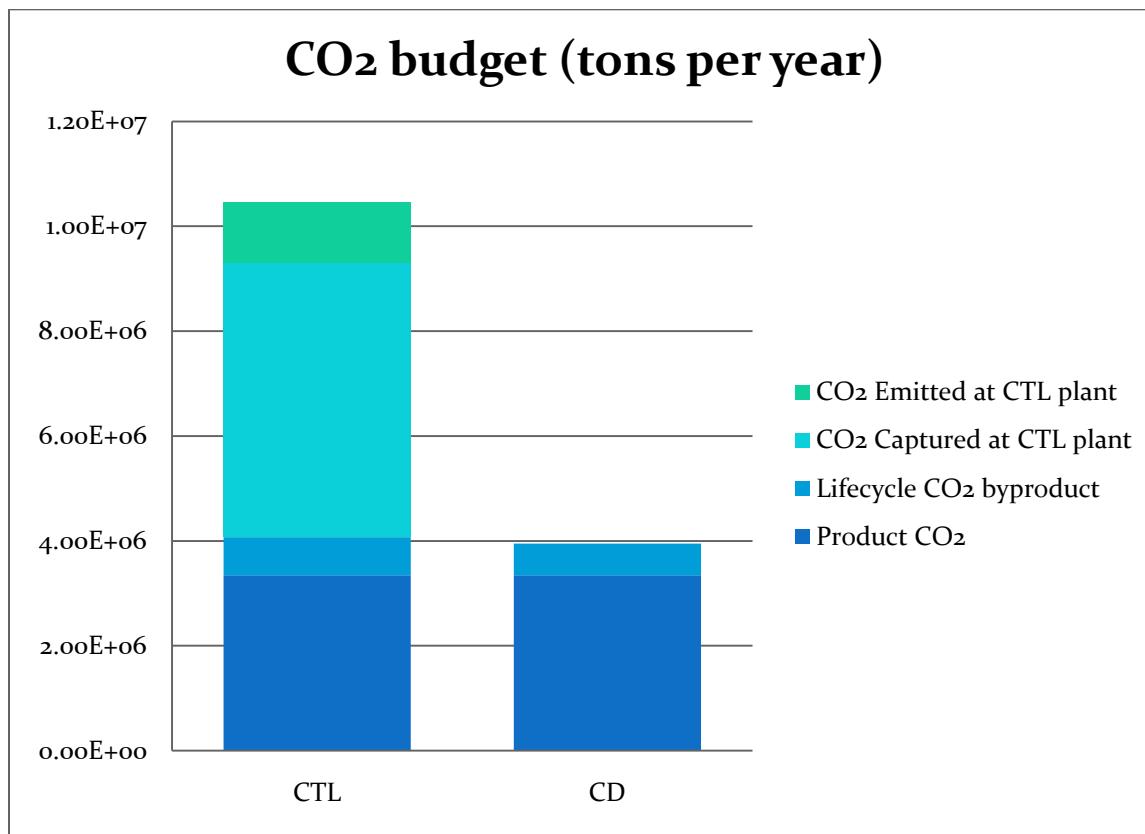


Figure 2.1. CO₂ budget of the proposed CTL plant and conventional diesel (CD) (from the Hatch Report [Drover, 2008], Table 15.1, page 71, Case 1, 20,000 barrels per day).

Based on this uncertainty, in order to mitigate the CO₂ released, a CTL plant would need to replace approximately 130 tons per hour of coal with biomass (dry weight), or 1.14 million tons per year. If this release were not mitigated, the Fairbanks North Star Borough CO₂ footprint would increase by approximately 30% (Holdmann and Murphy, 2008). On a per-gallon basis, this amount is an extra 7.46 pounds of CO₂ per gallon of fuel produced, or approximately 35% additional CO₂ from this fuel.

The release of CO₂ to the atmosphere could be mitigated through the use of biomass in three possible ways: (1) by using locally grown biomass as feedstock to replace some of the coal, (2) by capturing CO₂ from the CTL plant to create biomass in local forests by natural tree growth, or 3) for biomass projects in other parts of the globe, possibly supported directly or through a carbon-credit market.

The production of biomass in northern climates is currently being surveyed as part of this study, but current estimates are that about 1 ton of biomass is produced on 1 acre of forested land each year. This estimate means that to sustainably produce the necessary biomass for the proposed CTL plant, about 1.14 million acres of land would need to be used for harvest rotations. This corresponds to about 1,786 square miles, or a square of approximately 42 miles per side. The gathering of biomass would be complicated by rivers and streams, land ownership issues, and the distances required to transport the fuel.

The “no increase in carbon footprint” issue is not simple, especially with respect to biomass. For the collection of biomass in the Fairbanks project, the following factors must be considered:

- the energy required for harvest and transport of the biomass
- the CO₂ released by damage to natural soils in harvested areas
- the energy required to process and dry the biomass

All of these factors would result in a decrease in the effective CO₂ offset from the use of biomass.

The first two CO₂ mitigation options mentioned earlier—the use of local biomass to replace part of the coal as feedstock and the use of biomass production to absorb CO₂ released to the atmosphere, with special attention paid to algae production—are covered in detail in the following sections.

Impacts of Biofuels on CTL Plant Design

Mixing of Biofuels and Coal for Feedstock

Coal plants are, by design, suited to burn a fuel type with a given set of properties. Adding a different feedstock such as wood will change the way the fuel is burned, which can adversely affect gasification and, ultimately, the product. The main properties that differ between coal and woody biomass (the fibrous material) are moisture content, fuel density, and the volatile content. In addition, the feeding systems may have to be altered, as the coal delivery system is generally set up only for coal. Adding a fibrous and moist biomass product could affect the delivery system, though mixing the coal and biomass before delivery could reduce the effects. For higher percentages of biomass (~10–40%), a

dedicated biomass-delivery system would need to be established (Hughes, 2000; Robinson et al., 2003).

The feasibility of cofiring biomass with coal has been proposed in many places, with the main concern largely rooted in the price of delivered biomass feedstock. Biomass coal firing is only cost-competitive if a reliable and inexpensively delivered biomass source is available in areas of more high-cost coal (Robinson et al., 2003). A delivered biomass cost of \$15 or less per ton is the maximum price for cofiring to be economically close to that of coal. Cofiring with biomass will not greatly reduce the NO_x and SO_x emission, but it will significantly reduce CO₂ emissions. The availability of local biomass is attractive over other cofiring technologies, still in the research and development stage. Biomass is generally more expensive than coal, at \$1–\$4 per MMBtu (million British thermal units), whereas the price of coal is generally more stable, around \$1 per MMBtu (Robinson et al., 2003).

Biomass burning, which emits CO₂, is considered carbon-neutral if the biomass is sustainably harvested, because carbon in biomass is part of the active carbon cycle. The amount of carbon released during burning equals the amount consumed during growth. Burning biomass that would otherwise end up as landfill material also reduces the amount of carbon released into the atmosphere. As the biomass breaks down, it releases CH₄ (methane), which is believed to be 21–23 times more potent a factor in global warming (Sami et al., 2001), that is, 1 pound of CH₄ is equivalent to 21–23 pounds of CO₂ (Malmsheimer et al., 2008).

Baard Energy, LLC in Ohio, which has proposed building a new CTL plant, estimates a use of 28,000 tons of coal per day, utilizing up to 30% per weight in biomass to generate up to 53,000 barrels per day of Fischer-Tropsch oil (Baard Energy, 2009).

A biomass feedstock in place of coal would need to be relatively easy to produce, preferably year-round. This requirement is a big factor in Interior Alaska, as the winters are characterized by extreme cold that forces most photosynthetic organisms to shut down until the temperature warms above freezing. Reduced photosynthesis due to extreme cold limits potential sources of woody biomass or an outdoor algae farm.

Willow as a Managed Crop for CO₂ Sequestration and Biofuel

Willow is a fast growing woody tree found in many high-latitude areas. Under the right conditions, willow can reach a harvestable size within a growing season. Methods for determining the biomass production of willow include a destructive one (burning, drying) and a nondestructive one (measuring basal diameter and height). The most accurate measurement is thought to be drying and weighing the wood, though Nordh and Verwijst (2004) found that the results of both measurement methods conducted on the same tree

were not overly different. Measurements can aid in a relatively fast assessment of the biomass within a stand

In Alaska, abundant sunlight during the summer months provides for an environment of rapid growth for wood biomass such as the various willow species. Willow has been studied intensely in Sweden and New York as a potential biomass feedstock. A few studies have been undertaken in Alaska, but to a lesser extent.

Willows grow very fast, are easy to propagate, can be planted with very close spacing, have a broad genetic base, and continue to re-sprout after many harvests (Keoleian and Volk, 2005). The abundance of many native species of willows in Interior Alaska makes willows an ideal choice for a biofuel crop. The biggest barrier to willow as biomass production is the amount of land required to produce enough biomass to make the effort worthwhile. Interior Alaska has a large amount of unused land, but much of it would be unsuitable for a plantation due to soil, geographical, and topographical conditions, such as deep, wet valleys and rocky outcrops.

A life cycle assessment of willow was conducted on a bioenergy cropping system in New York (Heller et al., 2003). The New York experiment has managed to produce 55 units of biomass per year for every unit of fossil fuel needed to run the crop. To enhance the growth of willow, the crop management used an inorganic nitrogen fertilizer, a non-renewable resource added to the system. They found that substituting sewage sludge for fertilizer has increased production by up to 40% and reduced fossil fuel input. The study concluded that CO₂ emitted in combustion of the biomass is absorbed in the growing of the biomass, being carbon neutral, though the production processes do contribute to the system's net global warming potential.

Kopp et al. (2001) looked at willow clones and a poplar hybrid over 10 years while harvesting annually. The planted trees were spaced 0.3 by 0.3 meters and were harvested annually. Half of the trees were fertilized with nitrogen, phosphorous, and potassium, and all trees were irrigated starting in the third growing season. The growth rates of the willow clones fit the logistic growth curve with r^2 values between 0.91 and 0.54, suggesting that adapted willow clones can be productive and harvestable for at least 10 years before it is necessary to replant. The results of this study found that while fertilizer application did not increase productivity, it did speed up the time to reach the maximum production.

West and Marland (2002) noted that during a 20-year study of willow biomass and production in New York, their CO₂ sequestration rate was $1,835 \pm 588 \text{ lb C acre}^{-1} \text{ yr}^{-1}$ (roughly one ton per acre per year). This rate of biomass harvest is much higher than we can expect in Alaska.

A renewable source of feedstock such as biomass allows for a constant supply of fuel without expensive mineral-extraction costs, though harvesting biomass is not inexpensive

either. The costs quickly add up for transportation vehicles, fuel, planting, harvesting and tending labor, storage facilities, and fertilizer application.

A similar project in Fairbanks would be limited by fertilizer resources. Though sewage sludge is available in Fairbanks for use as fertilizer, the Interior's low population creates a minute amount of sewage sludge in comparison with that created by New York's high population. Sewage sludge would need to be supplemented with a more expensive, CO₂-producing inorganic fertilizer, not to mention the costs of transporting such an amount of fertilizer.

Willow Studies in Alaska

Garber-Slaght et al. (2009) detail the opportunities for woody biomass fuel crops in Interior Alaska. The authors looked at past studies of willow cultivation and revegetation in Alaska.

In 1977, Alyeska Pipeline undertook a study to revegetate disturbed willow areas. The plan was to plant 1.5 million willow cuttings on 890 acres along the Saganavirktok, Atigun, and Dietrich River valleys. The planting failed due to lack of research, and a new study was commissioned to find the best ways to reintroduce willows to disturbed areas. The new study was conducted by Zasada et al. (1981).

The study looked at the willow species *Salix alaxensis* and found that the best method of revegetation was to clip the willows while the plants were dormant, during the winter months, keeping the cuttings frozen until planting in early summer. For the highest transplant survival rate, a hole was cut in the ground with a shovel, the clipping was inserted, angled for best penetration, and a fertilizer was applied. Low nutrient levels were found to support the cuttings adequately, as long as there was little to no competition from grasses, as the grasses limit the light availability to the transplanted cuttings. Early summer was found to be the most suitable time to transplant the cuttings, though the best method was to transplant greenhouse-raised seedlings. In 1987, while studying the establishment of willow browse along the Trans-Alaska Pipeline, Densmore et al. (1987) found that cuttings needed to be ¼–½ inch in diameter and 12–15 inches long for best survival when transplanted.

In 2001, when the Pipeline was vandalized and crude oil spilled onto the ground, the resulting cleanup utilized these aforementioned methods. The ground was initially stabilized by introducing two short-lived grass species (*Puccinellia borealis* and *Lolium temulentum*), followed by 11,500 willow cuttings and 200 spruce trees. The area was fertilized with 360 pounds per acre of 10-10-20 fertilizer, and after 3 years, the willow cuttings had grown 4–5 feet high with an 80–88% survival rate (McKendrick, 2005).

Since the initial Pipeline study, there have been many manuals produced on how to revegetate by using willow cuttings (Miller et al., 1983; Alaska Department of Fish and Game, 1986; Densmore et al., 2000; Walter and Hughes, 2005). The basic lessons learned convey the same messages found in the study by Garber-Slaght et al. (2009).

- Local Alaska willows (particularly felt-leaf willow) can be grown easily from cuttings if proper handling procedures are used and field conditions are conducive to cutting survival.
- Moist soil conditions are important for dormant cutting survival. Watering for the first several weeks is important.
- Fertilizers will increase growth during the first few growing seasons.
- Weeds and grasses can severely stunt the growth of willows in the first year. Competition from grasses can kill willow plantings.
- Cuttings should be harvested during the dormant season and planted as early as possible in the spring.

The Garber-Slaght report provided growth rates and biomass production from a study conducted in a Conservation Reserve Program (CRP) field near Delta Junction. Woody samples taken from a 3-year-old field averaged 1,045 lb/acre, and a 4-year-old field averaged 1,000 lb/acre. A similar study at the Chena Flood Project yielded high-end numbers of 1,047 lb/acre for a 5-year-old field, and low-end numbers of 464 lb/acre and 590 lb/acre. The half-ton biomass harvests reported in Alaskan studies are significantly lower than the 4–12 oven-dried tons/acre reported in the New York study. Granted, the Alaskan surveys were of naturally occurring willow stands.

For the proposed CTL plant, if we doubled the average Interior Alaska harvests through management, calculating an even ton of oven-dried biomass available per acre, and we used this biomass as fuel for the CTL plant, ultimately offsetting the CO₂ released to the atmosphere (Figure 2.2), we would need around 1.14 million tons of biomass, meaning 1.14 million acres of well-managed, fertilized, and harvested willows (equal to a square 42 miles on each side). In order to maintain an adequate supply, multiple stands would need to be grown to allow the willows to reach their full growth potential and to maximize biomass harvests. Achieving this amount of biomass might mean increasing the harvestable area, understanding that the trees are dormant during winter, decreasing the growing time.

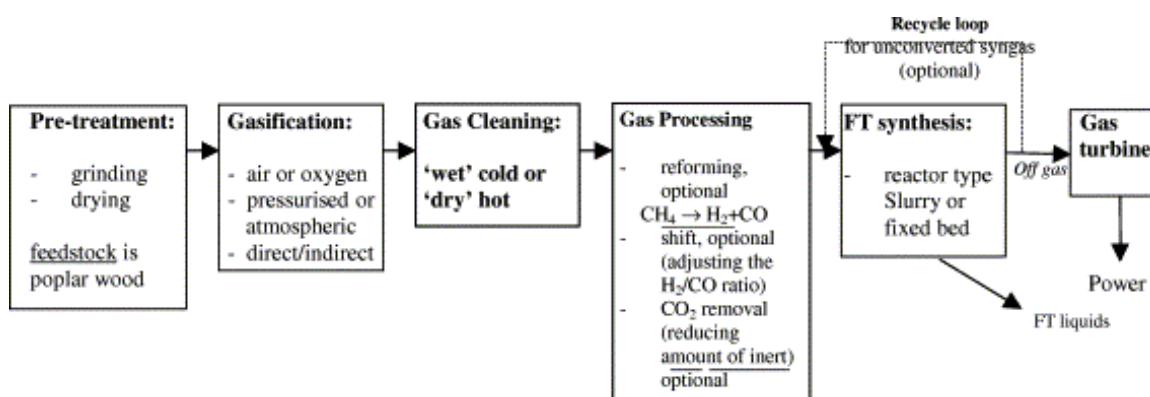


Figure 2.2. A basic schematic view of the key components for converting biomass to FT liquids combined with gas turbine (combined cycle) power generation (from Tijmensen et al., 2002).

In considering a 100% biomass-fired CTL plant (replacing all the coal with biomass), we would need to produce 10 million acres of biomass for minimum annual feedstock, and this is without additional stands. This amount of land equals 15,625 square miles, or a square 125 miles on each side, which would be cost-prohibitive to maintain, harvest, and transport, and thus is not considered further in this report.

Two measures must be taken into consideration when growing biomass for cofiring in a CTL plant: the cost of growing the biomass and the cost of harvesting the biomass, both in dollars and in cost to the environment. The New York willow study saw a CO₂ emission of 1.3% of the harvested biomass in the management of the willow stands (Heller et al., 2003). However, it should be noted that this study does not include the transportation of materials or resulting biofuels over the distances needed for a project of the scale needed in Fairbanks. Life cycle emissions in Fairbanks would likely be much higher.

Natural Carbon Sinks and Sources

The term *carbon sequestration* is used to describe natural and artificial methods of removing CO₂, which is the primary anthropogenic greenhouse gas (GHG), from the atmosphere for geological underground storage or biological incorporation in vegetation, microorganisms, and soils. Carbon sinks naturally remove CO₂ from the atmosphere for long-term storage of carbon. Forests sequester carbon continuously as they grow and convert atmospheric CO₂ into stable forms of carbon (Malmesheimer et al., 2008; U.S. Geological Survey, 2008; Borjesson, 1999; Fresco, 2006; Heller et al., 2003). The interaction of atmospheric CO₂ with forest stands is illustrated in Figure 2.3.

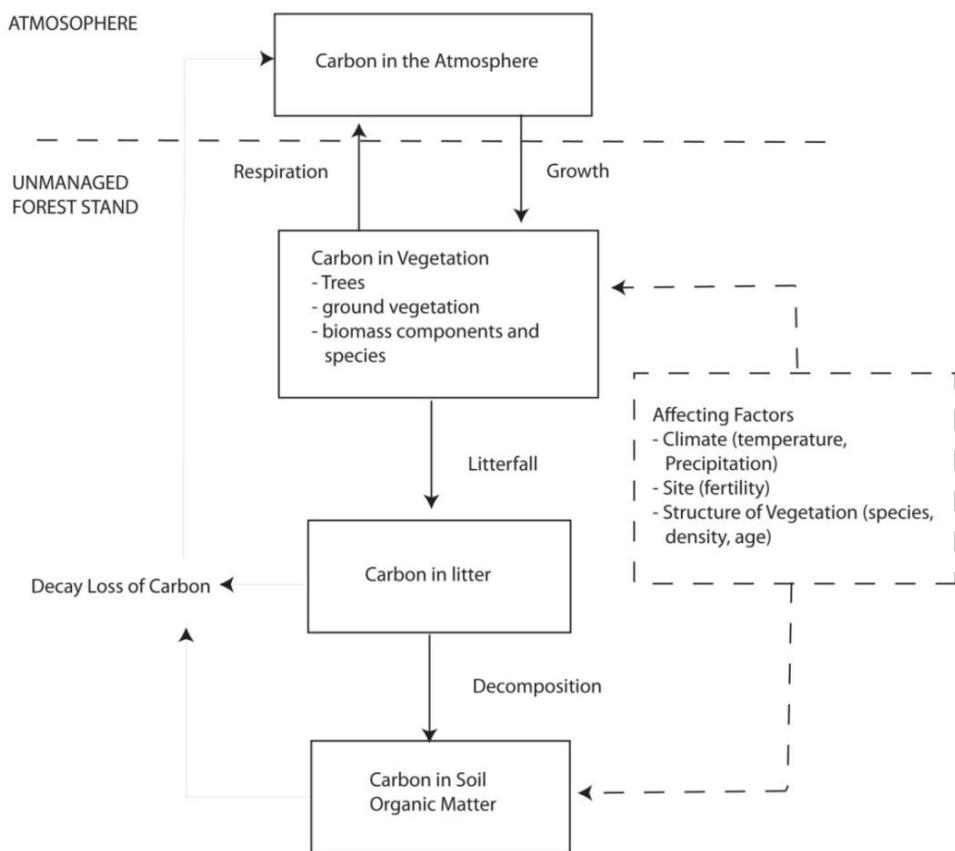


Figure 2.3. Outline of the atmosphere: forest carbon interactions (from Karjalainen, 2006).

In the Fairbanks North Star Borough, carbon sequestration naturally occurs, as carbon from the atmosphere is stored in live and dead vegetation as well as in organic matter in soils. The process is most prevalent in the forests of Interior Alaska, with its predominant mix of white and black spruce, paper birch, balsam poplar, black cottonwood, and quaking aspen. Carbon is also stored long-term in forest products such as lumber for buildings, house frames, and furniture (Society of American Foresters, 2007), but not in timber harvested for combustion purposes such as processing round logs and manufacturing wood pellets into heating fuel. The storage capacity for CO₂ on earth, as estimated in 2005, is shown in Table 2.1.

Table 2.1. Estimated world sink capabilities of CO₂ disposal options (from Stewart and Hessami, 2005).

Sequestration Option	Worldwide Capacity
Ocean	1000 GtC
Deep saline formations	100–1000 GtC
Depleted oil and gas reservoirs	100 GtC
Coal seams	10–100 GtC
Terrestrial	10 GtC
Utilisation	<1 GtC/year

Note: 1 GtC = 1 gigatonne (Gt) of carbon, or 10⁹ metric tonnes of carbon, or 1000 megatonnes (Mt) carbon, or 1 pentagram (1Pg) carbon.)

Estimates vary of amounts of carbon sequestered in forests of the United States. Forest trees alone are estimated to sequester around 200 million metric tons of carbon (Ruddell et al., 2007). When all vegetation and the soils of the forest are included, however, the estimated amount increases to about 1,146 billion metric tons of carbon. Approximately 37% of the 1,146 billion metric tons comes from low-latitude forests, 14% from mid-latitude forests, and 40–49% from high latitudes including Interior Alaska (Dixon et al., 1994; Fresco, 2006). Much of the carbon in high latitudes is in the form of peat bogs, some of which are in permafrost areas, effectively immune to decomposition due to biological processes.

Four processes are involved in controlling storage and release of carbon in vegetation at high latitudes: (1) the rate of plant growth including that of mosses and lichens; (2) the rate of organic matter decomposition; (3) the rate of permafrost formation; and (4) the frequency and severity of fires (Kasischke et al., 1995). During the winter months, carbon sequestration is greatly reduced as the ground and soil freeze. Opportunities to effectively sequester and store carbon are limited, therefore, to late spring, summer, and early fall. In addition, during the inactive winter season for forest growth and photosynthesis, wood is frequently burned locally as heating fuel, which further offsets sequestration efforts.

The capacity of a forest to sequester carbon is a function of site productivity and the available areas of actively growing vegetation, living trunks and branches, foliage, litter, soil, and standing and fallen deadwood. Sequestration rates for broadleaf trees such as birch and aspen are generally higher than for conifer trees, which have less leaf surface area. Since hardwood (broadleaf) trees are usually deciduous, however, their net carbon sequestration often approaches that of conifers. Forest stands of mixed species and variable age have a far higher capacity for carbon sequestering than forest stands of single species. The reason for the higher capacity is at least in part due to the larger leaf area of a

mixed forest (Malmsheimer et al., 2008). There is also a trend of decreasing CO₂ uptake in forests at increasingly higher latitudes (Valentini et al., 2000).

Cool soils like those of high latitudes or the deeper layers of the ground are most vulnerable to climate change as stored carbon is released with increasing temperatures. The sensitivity to warming trends suggests that loss of soil carbon in northern terrestrial ecosystems can serve as an indication and early warning system for anticipated responses and impacts of global change in other regions and ecosystems (McGuire et al., 2006, 2007). The loss of stored soil carbon due to higher temperatures could substantially offset any carbon sequestration effort in Alaska and elsewhere in the United States.

There is still much uncertainty, however, as to the amount of carbon flux in soils. Efforts such as the Deep Soil Carbon Project (U.S. Geological Survey, 2008) are underway to improve our understanding of the carbon stored in high-latitude soils. The findings to date of the many samples examined and analyzed have been variable. One reason for inconsistency in the results may be that all soils (due to lack of information) have been considered to have similar characteristics and behavior throughout Alaska. This view is obviously not the case, as permafrost is discontinuous in the weakly developed soils of Interior Alaska and varies with aspect, slope, elevation, and latitude (Fresco, 2006).

The potential for forest carbon sequestering over time increases with appropriate forest management. In part this approach is possible through afforestation (the planting of trees to establish new forested land), which increases the resource and the potential for uptake of carbon through photosynthesis. However, growth dynamics suggest that a newly established forest, similar to an unmanaged forest, reaches biological maturity; and the amount of sequestered carbon eventually approaches the amount emitted through decay. Still, proper management will keep forests growing at a higher rate to provide additional net sequestration benefits compared with those of an unmanaged forest. If an afforestation project is managed past biological maturity, human-induced timber harvesting can be an effective tool to improve forest health and allow more carbon sequestration than in a mature unmanaged forest. Therefore, procedures to mitigate carbon and the impact of climate change within existing managed forests should be encouraged and recognized.

A 1995 study in southern Finland (Karjalainen, 1996) examined a scenario of an unmanaged forest of single- or multi-species stands exposed to climate change. Climatic conditions were assumed to increase at 0.4°C per decade for the first 100 years, followed by 0.2°C per decade thereafter. Precipitation would also increase at 1% per decade for the first 100 years, followed by 0.5% every decade thereafter. Climate change was expected to have a larger impact on winter conditions than on summer conditions. Forests with single stands of spruce, pine, or two species of birch and a mixed-species stand were included in the study. The results showed an initial rapid increase in net ecosystem development,

carbon storage, and vegetation growth. However, the study also showed that after 5 to 40 years, the forests' net production rapidly dropped and became negative. Using ecosystem models, Karjalainen predicted that after 150 years the mixed-species area would start to show a barely positive net production under climate change. For the single-species stands, a more dramatic effect was predicted. At higher latitudes, surface temperatures were predicted to increase more and rise higher than the global mean increase. These results suggest a more pronounced effect of global change in Interior Alaska (Karjalainen, 1996).

Another study completed on sequestration rates was of the Tongass State Forest, the largest old-growth forest in the United States. After extensive ground surveys, a model was created with projections for net carbon flux to range from 0.33 megatonne (Mt) of annual carbon sequestration and 2.3 Mt of annual carbon emission for the 100-year period of 1995 to 2095. With no management of the forest, net flux during the following 100 years (2095 to 2195) was estimated to decrease to a range of 0.19 Mt of annual carbon sequestration and 1.6 Gt of annual carbon emission. If timber harvesting was halted in the Tongass from 1995 to 2095, the economic value of net carbon sequestered during that 100 years, assuming \$20/ton of carbon, would be \$4 to \$7 million USD (U.S. dollars) per year (1995 dollar value). Estimated carbon sequestration values for an additional 100 years remained similar (Leighty, 2006).

A forest may become a source of carbon after harvesting or during late mature-stand development with dieback and decay. The organic residue in the soil starts to decompose with release of carbon into the atmosphere when trees are harvested and removed. Forest fire also has a significant effect on carbon release into the atmosphere. Two boreal species, larch and pine, found primarily in Scandinavia and Russia, are fire tolerant. On the other hand, most tree species of Interior Alaska and Fairbanks such as black spruce are highly combustible. In wildfires, the ground along with trees and other vegetation burn. Canopy fires kill and scorch the aboveground biomass including the cambium layer of trees. Smoldering ground fires destroy belowground humus and organic soil layers. In addition, as the organic matter of the soil burns, the soil and ground temperatures increase. Frozen soil thaws to depths dependent on the severity of the fire. In 1986, the effects of an Interior Alaska fire increased the soil temperature the following year by 5–6°C to a depth of 10–50 centimeters. Permafrost close to the surface thawed during the fire, and deeper permafrost thawed with increasing soil temperature. Seven years after the 1986 fire, the depth of ground without permafrost had increased from 40 to 140 centimeters (Kasischke et al., 1995).

The burning of actively growing forest vegetation is less significant for carbon sequestration than the burning of the organic soil layer. Re-growth of the forest quickly offsets the burned areas aboveground, whereas burning of the layers belowground releases more carbon than is quickly re-stored (Kasischke et al., 1995). Managing Interior Alaskan forests for carbon sequestration by fire, therefore, is not ideal. The increase in soil activity

releases more carbon than can be sequestered during the short growing season. If the ground could be kept frozen and if the growing season were longer, forest fires might be a management tool for generating forest carbon sinks.

Given the uncertainty in the rates at which carbon is being absorbed and emitted by Alaskan forests, the only statement that can be made with certainty is that it is not clear what management strategy can be undertaken to increase the uptake of carbon from the atmosphere. It would be difficult, therefore, to claim any credit at all for the implementation of any management scheme for carbon management. No large swaths of land are available for planting trees, and local wildfires are increasing in intensity and frequency.

Other Natural Carbon Sinks

Forest ecosystems are not the only sequesters of carbon. Oceans and lakes have long been a sink and a source of carbon. With growth and decay occurring continuously, capturing and releasing carbon, the ocean is more of a sink than a source. Lakes, however, are more of a source. The oceans' large area, continuous movement, and constant replenishment of life allow the continuous storage of carbon. The storage mechanism is mostly algae with calcium carbonate (CaCO₃) shells, which utilize the CO₂ dissolved in the ocean from the atmosphere. Over a period of 100 years, it is estimated that around 80% of today's anthropogenic emissions of CO₂ will be absorbed by the ocean.

One suggested method for sequestering CO₂ is by direct injection into the ocean. This method would reduce peak atmospheric CO₂ concentrations and slow their rate of increase. It is estimated, however, that, if this method were used, 15–20% of the CO₂ injected into the ocean would leach back into the atmosphere over hundreds of years (Stewart and Hessami, 2005). The effects of increased CO₂ in the marine environment in such concentrated amounts and areas would negatively affect the marine ecology. In particular, recent studies have documented that increasing CO₂ concentrations can affect the pH of ocean water, and affect the ability of marine organisms to form shells, thus limiting the amount of carbon that can be captured, and potentially causing massive disruption of ocean food chains.

Marine fertilization is a method of oceanic injection that can enhance the biological carbon uptake. Small-scale fertilization experiments using the micronutrient iron have been conducted in Australia, but scientific research suggests that this method of sequestration has limited potential, high costs, and a high level of uncertainty (Stewart and Hessami, 2005).

Ocean Urea Fertilization

This section on Ocean Urea Fertilization, the process of fertilizing the ocean with urea to spur phytoplankton blooms, is based on a study by Romero (2007). Ocean urea fertilization is similar to iron fertilization, except that urea is used. When phytoplankton form, they pull CO₂ out of the atmosphere. When phytoplankton die, they sink to the bottom of the ocean and sequester the CO₂ that they used to form. However, the sequestration of carbon depends upon the depth to which phytoplankton sink: If they only sink to the mid-layers of the ocean, the CO₂ will be re-released; phytoplankton must sink to the deep ocean for CO₂ to remain sequestered.

Urea fertilization faces problems similar to those of iron fertilization. Fertilization could cause an increase in fish populations as their food supply increases. However, as phytoplankton decay, the dissolved oxygen in the water is depleted, which may adversely affect fish populations and the marine ecosystem. It is important to note that urea is produced from natural gas through an industrial process that emits CO₂, which must be considered when calculating the net CO₂ sequestered through this process.

Ocean Iron Fertilization

Ocean iron fertilization is the process of depositing iron onto iron-depleted sections of the ocean surface in order to stimulate phytoplankton blooms. According to Powell (2008), whose work has provided the information for this section, areas that are rich in nutrients such as nitrate, phosphorus, and silica, but depleted of iron are ideal locations for iron fertilization. The phytoplankton feed on the nutrients, but cannot form without iron. Most areas of the ocean get iron from river sediment and winds that carry iron dust from the land; however, some areas of the Pacific Ocean do not get iron from winds or river sediment and are, therefore, iron-depleted and cannot support phytoplankton.

Adding iron to nutrient-rich but iron-depleted areas of the ocean creates phytoplankton blooms on the surface of the ocean. Phytoplankton that generate carbonate shells, such as diatoms, pull CO₂ out of the atmosphere when they form; when these organisms die, their shells sink to the bottom of the ocean and sequester CO₂. However, in order to sequester CO₂, phytoplankton must reach the deep layers of the ocean—depths below approximately 1000 feet. Many phytoplankton are eaten by predators before they can reach depths where the carbon can be sequestered. Phytoplankton that reach the bottom of the ocean must remain there to sequester carbon, but strong ocean currents can pull phytoplankton that are on the bottom of the ocean back to the surface. Twenty to fifty percent of the CO₂ ends up in the middle layer of the ocean where it can be stored for decades; this is not ideal, but can help buy time until advances in carbon mitigation can be made.

Measuring exactly how much CO₂ is sequestered with ocean iron fertilization is a difficult task, and there are undesirable side effects associated with this method of sequestering CO₂. The ecological effects of creating phytoplankton blooms are a concern, as phytoplankton blooms could possibly deplete the deep ocean waters of oxygen as the phytoplankton decay. In the decay process, other gases such as methane and nitrous oxide may be released. The depletion of the dissolved oxygen in the water may cause anoxic conditions, leading to fish kills and dead zones as areas of the ocean become hypoxic. In addition, the nitrate, phosphorous, and silica used up in an iron-fertilization phytoplankton bloom are no longer available downstream, where they would have contributed to natural phytoplankton growth.

There is concern, also, about the effect of iron fertilization on the ocean food web. Phytoplankton blooms could alter fish and whale populations; they may block sunlight from reaching sea life, or warm the ocean and alter currents. A possible positive side effect is the production of dimethyl sulfide from phytoplankton blooms. When emitted into the atmosphere, dimethyl sulfide fosters cloud formation, which could help cool the earth. Results from pilot tests of ocean iron fertilization show that iron fertilization of the ocean may not be the most effective method of carbon sequestration.

In another study on ocean iron fertilization (Stewart and Hessami, 2005), iron was added to seawater at a 10-by-10 square kilometer patch of ocean to increase naturally occurring concentrations. Results were dramatic. Chlorophyll increased by 30 times over the course of the experiment, and plankton biomass increased by an order of magnitude, which translates to 100,000 kilograms of fixed carbon (or 1 metric ton per acre!) (Stewart and Hessami, 2005). Drawbacks to these fertilization methods include changes in plankton structures that can have long-term effects on the ocean ecosystem. It is thought that with increased production, there could also be an increase in methane gas, produced by natural processes. Decay would produce CO₂, which would negate the effort of oceanic fertilization.

Photosynthetic conversion in an enclosed and controlled environment is another option. Though not yet commercially viable, this system could prove useful in directly sequestering carbon from a CO₂-emitting industry. A conceptual design for such a system combines solar energy collection and a fiber optic light-delivery system to stimulate biological organisms in a bio-generator to produce useful by-products from CO₂ and other species. Cyanobacteria or microalgae have been suggested to perform the role of photosynthesis. In order to promote uniform growth of the organisms, the distribution of photosynthetic photon flux light in the wavelength range of 400–700 nanometers (nm) needs to be delivered to the bioreactor. At present, open-pond systems produce around 100 metric tonnes of biomass annually at a cost of around \$10,000 USD/metric tonne. Although the central role of technology limitations has not yet been properly addressed, a

number of facilities capable of mitigating over a million tonnes of CO₂ would have a significant impact on the reduction of GHG emissions.

Some studies have been conducted to sequester CO₂ and other pollutants from the atmosphere to create a terrestrial fertilizer to enhance terrestrial sequestration through soil and vegetation. One such project by Lee and Li (2002) proposed to remove CO₂, NO_x, and SO_x to create the fertilizer NH₄HCO₃ (ammonium carbonate). The compound, resultant through a process of solidifying CO₂ by innovative application of the NH₄HCO₃ and (NH₄)₂CO reactions, requires the use of natural gas and N₂ (nitrogen dioxide) to create the ammonium bicarbonate. The only issue with this compound seems to be that, though it is somewhat stable in its solid form, in its aqueous form, such as when wetted from soil water, it releases its solidified CO₂ into the atmosphere if heated. This quality could potentially negate sequestration efforts through expensive fertilizer creation.

Crop Residue Oceanic Permanent Sequestration

The following section on Crop Residue Oceanic Permanent Sequestration (CROPS) is based on a study by Strand and Benford (2009). Crop residue oceanic permanent sequestration is the process of storing crop biomass such as corn stalks at the bottom of the ocean, where it will be covered by sediment, and where its carbon content will be stored for thousands of years. This method of sequestration is untested. The process includes collecting and baling crop residue and then transporting it to the ocean to be sunk to depths of 1,000 to 1,500 meters. The marine environment is not capable of degrading lignocelluloses; therefore, the carbon content of crop residue will not be released.

Carbon sequestration efficiency—defined as the carbon sequestered, less the fossil-fueled carbon emitted during the sequestration process, divided by the crop residue carbon processed—would be 92%, based on estimates. This level of efficiency could reduce the annual global increase of CO₂ by 14% if 0.6 Gt per year of crop residues were sequestered. The CROPS method of sequestration does not require any new infrastructure. The necessary farm equipment, trucks, and barges are already in existence, which means that this method could be implemented quickly when compared with other methods of sequestration. The estimated cost of crop residue sequestration is approximately \$135 per tonne of crop residue sequestered or \$340/t of carbon sequestered.

The environmental impact on the marine environment of depositing large amounts of crop residue onto the ocean floor is unknown. However, they report the finding that depositing the crop residue on alluvial deltas at the base of rivers flowing into the ocean, such as the Mississippi, may have less ecological impact on the marine environment, because fresh plant matter is naturally deposited in alluvial fans after storms. Depositing the crop residue in a compact area could also help reduce the ecological impact. Studies

will have to be conducted to determine the interaction between crop residue and the marine environment.

Algae Production and Non-Photosynthetic Algae

For microalgae biomass, higher energy efficiencies for converting solar energy into chemical energy can be achieved. Based on present understanding, microalgae could convert up to 5% of sunlight energy to biomass (Schenk et al., 2008).

Increased photosynthetic efficiencies and increased oil yields have made microalgae biomass attractive to biofuel producers. Oil content of algae species varies (Table 2.2), and oil production of microalgae has been reported to yield 15–300 times more oil for biodiesel production than traditional crops per area used (Table 2.3).

Table 2.2. Oil content of various algae used for biomass production (from Christi, 2007).

Microalga	Oil content (% dry wt)
<i>Botryococcus braunii</i>	25–75
<i>Chlorella</i> sp.	28–32
<i>Cryptothecodium cohnii</i>	20
<i>Cylindrotheca</i> sp.	16–37
<i>Dunaliella primolecta</i>	23
<i>Isochrysis</i> sp.	25–33
<i>Monallanthus salina</i>	>20
<i>Nannochloris</i> sp.	20–35
<i>Nannochloropsis</i> sp.	31–68
<i>Neochloris oleoabundans</i>	35–54
<i>Nitzschia</i> sp.	45–47
<i>Phaeodactylum tricornutum</i>	20–30
<i>Schizochytrium</i> sp.	50–77
<i>Tetraselmis sueica</i>	15–23

Table 2.3. Comparison of crop-dependent biodiesel efficiencies from plant oils (from Schenk et al., 2008).

Plant source	Biodiesel (L/ha/year)	Area to produce global oil demand (hectares × 10 ⁶)	Area required as percent global land mass	Area as percent global arable land
Cotton	325	15,002	100.7	756.9
Soybean	446	10,932	73.4	551.6
Mustard seed	572	8,524	57.2	430.1
Sunflower	952	5,121	34.4	258.4
Rapeseed/canola	1,190	4,097	27.5	206.7
Jatropha	1,892	2,577	17.3	130 (0 ^a)
Oil palm	5,950	819	5.5	41.3
Algae (10 g m ⁻² day ⁻¹ at 30% TAG)	12,000	406	2.7	20.5 (0 ^a)
Algae (50 g m ⁻² day ⁻¹ at 50% TAG)	98,500	49	0.3	2.5 (0 ^a)

Microalgae have a short harvest cycle of 1–10 days, depending on the process used, which allows for increased harvests with significantly increased yields. The methods vary in growing these microalgae, but many new processes are aimed at low-light intensity and increasing light capture and conversion efficiencies, which lead to lower fertilizer application and decreased nutrient input. The biomass can be grown in a bioreactor, needing lower input of water, which adds to the benefits. Algae biomass can also be gasified or pyrolysed to create a range of biofuels and agrichar as part of a CO₂ sequestration strategy. The waste from this process can be disposed of in an environmentally safe way.

There are two basic systems for growing algae: open-pond systems and closed-reactor systems. Open ponds are less expensive to construct, though this can lead to contamination from the outside environment; freezing and light might be issues in winter, as well. Closed bioreactors are a totally enclosed system. A closed-bioreactor design saves energy, water, and chemicals; it also supports up to five times the productivity per unit area of an open-pond system. Some microalgae require moderate-to-low light intensities, and some even exhibit lowered production rates in high light intensities. Photobioreactors have been developed that provide a method in which sunlight is diffused over a large surface area to provide moderate light intensities. Tubular reactors set in a fence-like structure are oriented in a north–south direction to reduce the amount of direct sunlight that hits the surface (Figure 2.4).



Figure 2.4. A closed photobioreactor system in Klotze, Germany, produces up to 100 t algae biomass per year in its 500 km of tubing (from Schenk et al., 2008).

The economics of microalgae biodiesel could potentially be more cost-effective than the current means of corn-based biodiesel. Currently, the production of a barrel of corn-based biodiesel (\$80) is close to that of oil (\$71); and when oil prices surpassed \$100 per barrel, it was more economical to produce biodiesel, though this is theoretical, as no commercially viable algal biodiesel source has been established. Now, if the microalgae biodiesel were to compete with these prices, looking at the land area used and yields (Table 2.3), the

estimated cost of a barrel of microalgae biodiesel in 2008 would have been \$52–\$91 per barrel. An Israeli company, Seambiotic Ltd., was not so optimistic about such low prices. They estimate that their dry algal production is \$0.34 USD/kg, with production at 20 g m⁻² day⁻¹ and with a total lipid content ranging from 8–40%. Assuming a 24% lipid yield, extracted at no further cost, the price per barrel is an alarming \$1.42 USD/kg or \$209 USD/bbl. With a more optimistic 40% lipid yield, the price would drop to \$0.85 USD/kg or \$126 USD/bbl. Note that all these are projected costs. Algae biofuel currently costs between \$100 and \$1000 per gallon, and is sometimes not even available at these prices.

A commercial, high-yield facility producing biofuel from algae will encounter costly operating expenses. One figure for the estimated cost of the annual overhead of a 50,000,000 gal/yr closed photobioreactor is \$1,461,200,000. This cost would yield biofuel at \$29.22 per gallon. Conversely, an open-pond system would only cost \$660,000,000 and produce biofuel that costs \$13.20 per gallon (Pate, 2009). Unfortunately, an open-pond system in Alaska is not practical due to freezing and contaminants.

Cloud (2009) suggests that a closed photobioreactor system will cost around \$500,000 per acre. Other figures are given at around \$1 million per acre. This cost is expensive when the rate of obtaining biofuel from algae is 10,530 gallons per acre per year (adjusted from Table 2.3).

Closed-system reactors might look more attractive in Alaska, as the closed system can be hooked up to any CO₂-producing waste-heat system to maintain a livable temperature, but light would still be a problem (see Figure 2.5). For three months a year, Alaska would have a great yield of biomass from algae, but throughout the months of low light, the production would cost more to maintain through artificial light than would be economically viable.

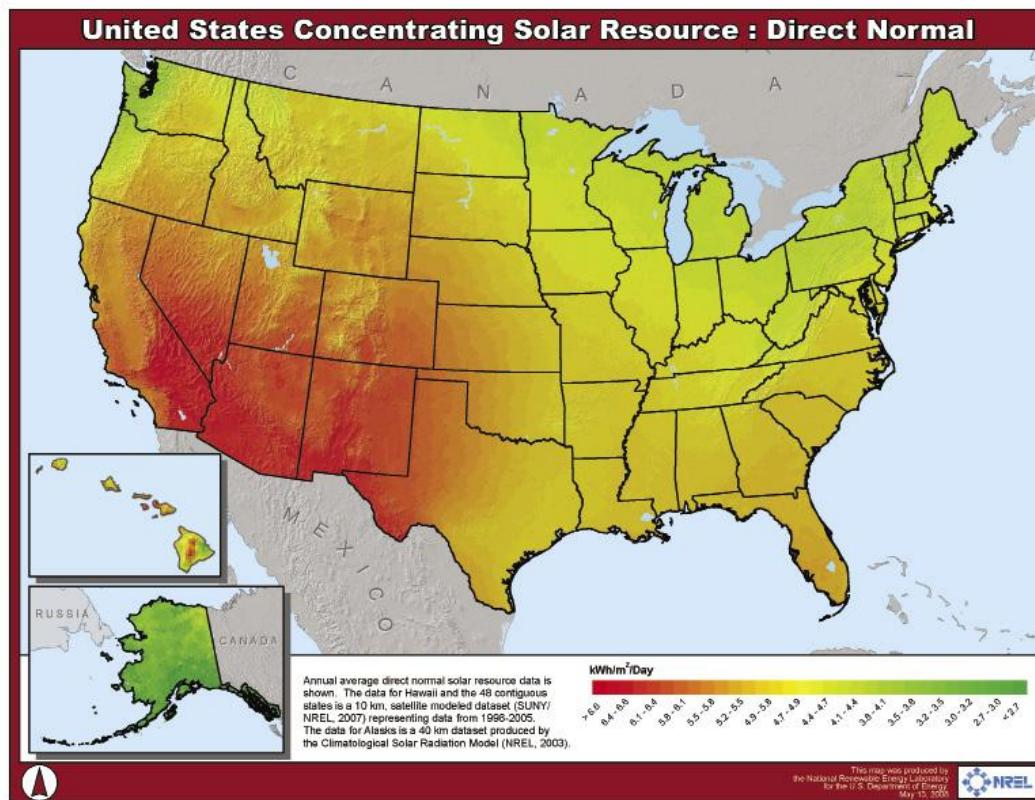


Figure 2.5. Annual average insolation in the United States (from State Energy Conservation Office, 2009).

Conclusions

Based on a literature review, the following conclusions can be established:

- Section 526 of the Energy Independence and Security Act of 2007 requires that if the federal government is to purchase fuel from the proposed CTL plant in Fairbanks, all the CO₂ produced by the plant must be captured and sequestered or mitigated.
- The plant configuration described by the Hatch Report releases at least 1.14 million tons per year of CO₂ into the atmosphere, which must be mitigated in some way.
- Using biomass as a feedstock is one proposed method for mitigating the released CO₂, which would require approximately one ton of biomass for each ton of CO₂ released, or 1.14 million tons per year.
- Growing willows as a locally available feedstock has been proposed, but local production rates have been measured at about 1 ton per acre per year.
- While willows grow naturally in many areas of the Fairbanks North Star Borough, no studies have been done to investigate the availability of large land areas for

- sustainable willow farming; potential obstacles, including land ownership, access to land areas, and transportation distances have been identified.
- Planting new forests to sequester CO₂ does not appear feasible on a local level.
 - Algae production absorbs CO₂ and produces additional oils that can be used for fuel, but this technology is still being developed in areas that are more temperate. The long, cold, dark winters in Fairbanks are not amenable to open-pond algae production, and costs of closed reactor systems are far too high for economic production of algae for fuels.

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CHAPTER 3

Current CO₂ Geologic and Non-Geologic Sequestration Projects

by Dominique Pride and Dennis Witmer

Introduction

Carbon dioxide is a greenhouse gas, and concentrations of it in the atmosphere are rising, contributing to global climate change. The scientific community consensus is that the rise in CO₂ is due at least in part to emissions from the combustion of fossil fuels. Because of this consensus, political pressure is being placed on emitters of CO₂ to reduce the amount of gas released into the atmosphere, especially emissions from larger point sources such as electrical power plants or petroleum refineries. Balanced against these concerns is the fact that our economic system has relied on vast amounts of inexpensive fossil energy, and the realization that reducing carbon emissions is likely to be technically challenging and result in at least some increase in the cost of energy.

Most of the fuels used by humans are carbon-based, created by plant matter through photosynthesis, which converts CO₂ from the atmosphere to carbohydrates for use as stored energy. Carbon dioxide is the main product of combustion from the burning of fossil fuels, and the amount of CO₂ produced is directly proportional to the amount of fuel consumed. For many years, it was believed that the CO₂ released during the combustion of fossil fuels was simply absorbed by plant growth, as shown in the carbon cycle illustrations in high school science textbooks. There are two basic ways of reducing human-produced CO₂ in the atmosphere: (1) by reducing the amount of fuel consumed, thereby reducing the overall emissions, or (2) by finding some way of fixing CO₂ so that it does not remain in the atmosphere. While reducing fuel consumption is an admirable goal, economic development, especially in large developing nations such as China and India, has proven to be tied to increasing use of energy. Politically, it is difficult for developed nations to enforce carbon emissions reduction in these places. In addition, there is the challenge of organized opposition to greenhouse gas legislation by the energy industry in the United States. These difficulties are why researchers in the United States and in other parts of the world are pursuing the preferred technical solution of finding some way to fix CO₂ so that it does not enter the atmosphere.

There are two main ways of fixing CO₂: by mechanically confining the gas to a container so that it does not escape to the atmosphere, or by chemically reacting the CO₂ with another substance so that it remains in a liquid or solid form. While the first method might seem impractical due to having to build a containment system, nature has provided containers that will work. Gas-tight porous regions within the earth's crust are of

considerable interest for this purpose, because they are natural containers for fossil oil and gas reserves. Once these substances are removed, the space they have vacated is available for storage of CO₂. The geologic structures that held fossil oil and gas reserves must be excellent containers, since they maintained their fluid inventories until their boundaries were pierced by the wells used to extract the fuel. The volumes these structures can hold are frequently large. One additional benefit of injecting CO₂ into these structures is that it aids in the recovery of additional oil (enhanced oil recovery, or EOR), either by dissolving in oil and reducing its viscosity (miscible EOR) or by simply displacing more viscous oil while remaining in a separate phase (immiscible EOR). Carbon dioxide can also be injected into other porous strata including saline aquifers or coal seams, which have the advantage of being more widely distributed and, therefore, possibly closer to the source of CO₂. This option provides no valuable products (oil), however, to offset the cost of injecting CO₂ into them. Fixing CO₂ through a chemical reaction with other species takes many forms in nature, including photosynthesis and plant growth, the weathering of mafic rock, or the formation of shells of sea animals. However, the rising concentrations of CO₂ measured in the atmosphere over the past decades (and verified over longer periods with other methods such as the analysis of ice cores from Greenland and Antarctica) show that these natural processes are not removing all the additional CO₂ that is being introduced into the atmosphere. Deliberate attempts are being made to accelerate these processes, and represent another way of reducing atmospheric CO₂.

Policy makers have reacted in two ways to the scientific identification of CO₂ as a major environmental issue: by negotiating treaties and passing laws that set goals for the reduction of CO₂ emissions (the Kyoto agreement and, in the U.S., the climate change legislation of 2009), and by passing laws and sponsoring research intended to address CO₂ emissions (the Energy Independence and Security Act of 2007). However, the feasibility of managing CO₂ emissions through any of these methods is still not well understood, especially the potential costs associated with each method. To define these issues more accurately, technology demonstration projects are funded, usually on a relatively small scale, with the goal of assessing the viability of a given option.

Tasks 3 and 8 of this project include the survey of technical literature (including the Web) for information regarding carbon sequestration technologies, with consideration of their applicability to a coal-to-liquids (CTL) plant in Fairbanks, and with attention paid to both the cost and the ability to sequester large amounts of CO₂ (millions of tons per year).

The proposed CTL plant to be built in Fairbanks would provide synthetic diesel fuel to Eielson Air Force Base, but would need to follow all procurement regulations relating to this type of fuel. In particular, Section 526 of the Energy Independence and Security Act of 2007 (see Chapter 2 under the section Emissions Analysis for exact wording) requires that the carbon footprint of any alternative or synthetic fuel be less than or equal to that of the

fuel it replaces. (Note: Bills have been introduced in both the House and Senate to repeal this provision during the 111th Congress.)

Carbon dioxide geologic sequestration techniques relevant to the proposed Eielson CTL plant are discussed in detail in Chapter 1. This chapter augments the information in Chapter 1, describes other non-geologic sequestration techniques, and discusses current CO₂ sequestration demonstration projects.

Carbon Sequestration Technologies

The geological sequestration of CO₂ is a frequent topic of recent research, with several methods for its attainment (see Figure 3.1). All these methods require that CO₂ be separated, purified (especially to remove water, which forms a corrosive acid when mixed with the CO₂), compressed, transported, and injected into geological formations. The Hatch designs (Drover, 2008) include the cost of separating CO₂ and compressing the gas to 20 atmospheres, but do not include the cost of additional compression, purification, transportation, or injection. Also not included in the Hatch designs is the revenue from the sale of CO₂ to potential customers, most notably the oil industry, which has been using CO₂ for enhanced oil recovery for decades. It should be noted that this industry would be expected to use the most cost-effective supplies of CO₂ available, so any economic analysis of the value of CO₂ must consider other possible sources for this use.

Six possible storage mechanisms are listed in Figure 3.1, but they can be grouped into three categories:

1. Sequestration in sites associated with current oil and gas fields (enhanced oil recovery using depleted oil and gas reservoirs, and injection into saline aquifers).
2. Sequestration in deep, unmineable coal seams (both with coalbed methane production and without associated methane production).
3. Other methods.

Of these methods, enhanced oil recovery is the only method that has an established positive economic value for CO₂ in the market. All other methods require some form of carbon tax to justify their implementation. (The cost of sequestration to comply with Section 526 of the 2007 Energy Independence and Security Act is a government-imposed cost—effectively a tax.) In this report, the “other” category includes several ideas unique to northern applications that have not been widely discussed in the technical literature because they depend on the presence of permafrost.

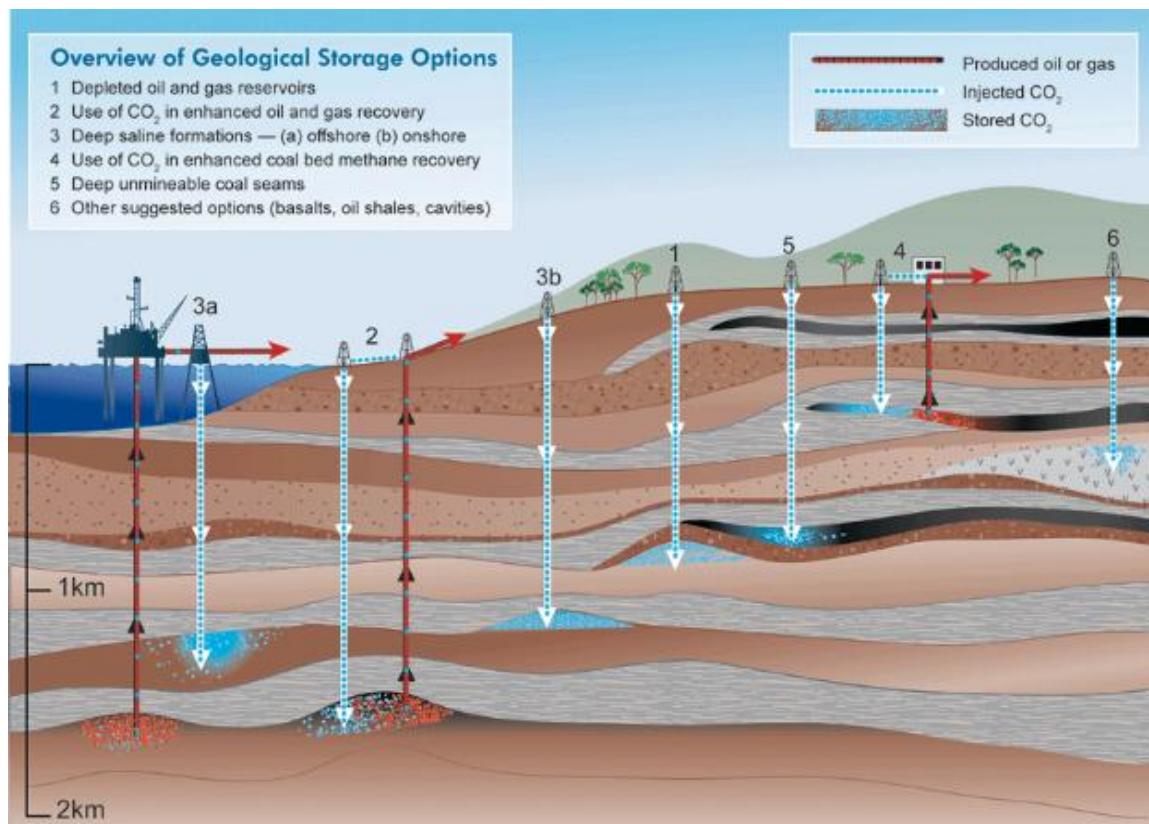


Figure 3.1. Methods of geological sequestration of CO₂ (from Geologic Storage Research, 2009).

An excellent summary of the current state of carbon-capture technology was published in the summer of 2009 in a report by the Carbon Capture Project (Cooper et al., 2009). This report, created by representatives from most of the major world oil producers, includes results from demonstration projects in progress. Central to this report is the issue of assuring long-term containment, which is possible only by a thorough understanding of the integrity of the formation into which the CO₂ is injected. This issue is best understood in existing oil and gas fields, where the accumulation of oil and gas proves the existence of effective sealing of the rocks, and provides assurance that long-term storage of CO₂ is viable. Other sites will need to be thoroughly characterized with the same techniques and rigor used by the oil and gas industries, and this will add considerable expense to any sequestration project not located within an existing oil and gas field.

Summary of CO₂ Sequestration Techniques

Enhanced Oil Recovery

Description of Technology

The information in this section on enhanced oil recovery (EOR) technology is based on a study by Chaney and Van Bibber (2006). Further discussion of the technology is provided in Chapter 1 of this report. Enhanced oil recovery using CO₂ is a tertiary method of recovering oil from partially depleted oil reservoirs. Tertiary methods for oil recovery are resorted to after primary (removing easily recovered oil) and secondary (waterflooding) methods have been exhausted. Primary oil recovery relies on natural pressure within the formation, while secondary oil recovery involves injecting water or gas to increase the pressure. For tertiary recovery, CO₂ is injected into the reservoir, and the injected CO₂ not only increases pressure but also improves fluid flow within the reservoir, allowing for greater recovery of incremental oil. At least 50% of the CO₂ injected into the reservoir resurfaces with the produced oil. The CO₂ is separated from the oil and then re-injected into the reservoir (Benson and Cook, 2005). Enhanced oil recovery using CO₂ is a mature technology that adds years of production to waning oil fields. In the United States, partially depleted oil reservoirs have been flooded with CO₂ since the 1970s.

A reservoir must display certain characteristics in order to be a candidate for EOR. If a reservoir is a candidate for CO₂ flooding, then it must be determined if miscible flooding (CO₂ dissolves in the oil and reduces viscosity) or immiscible flooding (CO₂ remains a separate phase that pushes out the oil) is appropriate. At pressures above 1,100 psi in reservoirs with light and medium oil, CO₂ mixes with oil, which allows for effective miscible recovery. Reservoirs with lower pressures and heavier oil must rely on immiscible recovery because CO₂ does not completely mix with oil. Instead, the CO₂ flood improves oil recovery by swelling the oil and reducing its viscosity. Miscible floods recover up to 50% more oil than immiscible floods, and can have residual oil saturation as low as 3–5% after CO₂ flooding. American Petroleum Institute (API) gravity is a measure of the density of oil as compared with water. If oil has an API gravity greater than 10°, it will float on water (American Petroleum Institute gravity scale, 2009). In order to qualify for CO₂ EOR, a reservoir must have a depth greater than 1,800 feet (549 m) and oil gravity greater than 13°. Flooding can be miscible at depths as shallow as 2,500 feet as long as the oil has a gravity of 40° or greater. At greater depths, miscible flooding can occur with lower oil gravities. However, miscible flooding is not possible with oil gravity less than 22°. For oil gravity between 13° and 22°, only immiscible flooding is possible.

Other characteristics indicative of a reservoir's amenability to miscible flooding include responsiveness to waterflooding and the oil recovery factor prior to CO₂ flooding. The best candidates for CO₂ EOR are reservoirs that have a 20–50% oil recovery factor after secondary recovery and prior to CO₂ injection. In order to recover a barrel of oil with CO₂ EOR, 7,000–8,000 standard cubic feet of CO₂ must be injected (approximately 0.5 tons of CO₂). A range of 8–11% of the original oil in place can be recovered using miscible

flooding. Before CO₂ injection, water must be injected into the reservoir to fill gas voids and to increase pressure within the reservoir to its original condition.

Previous Evaluations of CO₂ Enhanced Oil Recovery on the North Slope of Alaska

According to a study by Patil (2006), the Alaska North Slope (ANS) has pools of oil that could potentially be recovered through EOR, using CO₂ to flood the reservoirs (see Chapter 1). Patil evaluated CO₂ sequestration options for the ANS including EOR and injection into a saline aquifer. Enhanced oil recovery using CO₂ flooding is an attractive option, because additional oil can be recovered while sequestering CO₂ emissions. As of 2006, there were 67 sites in the United States using CO₂ EOR. The West Sak oil pool of the Kuparuk River Unit is a candidate for EOR because of its viscous oil deposits. The ANS has an estimated 20–25 billion barrels of original-oil-in-place of medium and heavy oil deposits (Patil, 2006). The West Sak oil pool has 7–9 billion barrels of original-oil-in-place.

The simulation used in Patil's study assumed a 40-acre area with 4 CO₂ injection wells (1 at each corner) and a production well in the center. Patil calculated that the economic feasibility of the project would be dependent upon the close proximity of a large source of high-purity CO₂. Due to shipment costs, the cost of an EOR project increases as the distance of the CO₂ source increases. Patil's simulation assumed CO₂ injection for 25 years at various percentages of pore volume. Capital expenditures included initial investments for the transportation, capture, compression, and storage of CO₂. Operating expenditures included labor and maintenance costs for the transportation, capture, compression, and storage of CO₂. A Monte Carlo simulation was used to find the probability distribution of the net present value (NPV) of the project; it showed that the storage ratio of CO₂ decreased as the percentage of oil recovery increased. The percentage of recovered original-oil-in-place increased, however, as the amount of injected CO₂ increased, until a plateau was reached where an increase in the percentage of pore volume injected did not increase the percentage of incremental oil recovered. For 50% pore volume of CO₂ injected, 9.7 Mscf (thousand standard cubic feet) of CO₂ needed to be injected to recover one stock tank barrel of oil. In the simulation, an EOR project that injected an average of 1.37 million tons of CO₂ annually and had a 38% sequestration rate would have a NPV nearly \$27 million higher with a \$10 per ton CO₂ credit than without CO₂ credits. NPV is sensitive to the oil price and the discount rate (Patil, 2006).

Patil's simulation showed that when 50% pore volume of CO₂ is injected, 20.62% of the original-oil-in-place is recovered. If these numbers are applied to the West Sak oil pool, between 1.4 and 1.8 billion barrels of incremental oil could be recovered by injecting between 14 and 18 Tscf (trillion standard cubic feet) of CO₂ (approximately 1 billion tons). The ANS has between 20 and 25 billion barrels of original-oil-in-place of medium and heavy oil deposits, as mentioned earlier, and 5–10 Mscf of CO₂ are needed to displace a barrel of incremental oil. An average of 7.5 Mscf of CO₂ is needed to displace a barrel of

incremental oil on the ANS. For a 20.62% recovery of original-oil-in-place, between 30.9 Tscf and 38.7 Tscf of CO₂ (3–3.5 billion tons) would be needed to displace the deposits. Currently, there are 8 million tons of CO₂ or 138 Bscf (billion standard cubic feet) of CO₂ readily available annually from drilling operations on the ANS. If additional CO₂ were to be shipped to the ANS from Fairbanks for EOR, the cost of a nearly 500-mile pipeline would have to be considered. Worth noting, also, is that the CTL plant in Fairbanks would produce about 5 million tons of CO₂ per year, which would require 200 years to supply the necessary volumes of CO₂ for recovery of oil from the ANS.

Patil (2006) also examined CO₂ storage in a saline aquifer. A simulation of 4.4 lb/sec of supercritical CO₂ injection into a saline aquifer over a 10-year period indicated an increase in gas saturation until injection subsides. Ten years after the end of the project, the plume begins to migrate vertically until it is trapped by the impermeable shale layer. The simulation showed that no CO₂ leaked from Layer 1, indicating that the less-permeable layer above it did not allow vertical migration of the CO₂ plume. The simulation also showed that there was no temperature gradient increase in the permafrost region caused by the injection of supercritical CO₂.

Current Demonstration Projects

Weyburn CO₂ Sequestration Project. The Dakota Gasification Company, a subsidiary of Basin Electric Power Cooperative, operates the \$2.1 billion Great Plains Synfuels Plant near Beulah, North Dakota (Dakota Gasification Company, 2009). The plant has been in operation since 1984 and under the ownership of the Dakota Gasification Company since 1988, when it was purchased from the United States government. The Lurgi gasification process is used at the plant to produce 153 million cubic feet per day of synthetic natural gas from lignite coal (Dakota Gasification Company, 2009). During the process, CO₂ is separated from other gases by a Rectisol unit (IEA Greenhouse Gas R&D Programme [IEA], 2009a). Since 2000, the Dakota Gasification Company has captured and transported a portion of its CO₂ emissions across the border via pipeline to EnCana Corporation's Weyburn Oilfield in Saskatchewan, Canada, for use in an EOR project (Perry and Eliason, 2004). The Weyburn oil field is a large field on the edge of the Williston Basin that has been in production since 1954 (Torp and Brown, 2005).

After the CO₂ is captured at the plant, it is dried to remove water vapor, which can corrode the pipeline unless high-cost alloy metals are used. Drying the CO₂, therefore, allows for the use of relatively less expensive carbon steel for pipeline construction. Once the CO₂ is dried, it is compressed by 2 eight-stage, integrally geared compressors to 2,700 psig (pounds per square inch gauge) to a supercritical state for pipeline transport (Perry and Eliason, 2004). No additional compression is required along the pipeline to the Weyburn oil field (Brown et al., 2001). The project required the construction of a 12-inch and 14-inch carbon steel pipeline 205 miles long that transports 5,000 tons of CO₂ per day

from the plant in North Dakota to the injection site in Saskatchewan (Perry and Eliason, 2004). Together, the compressors and the pipeline cost \$100 million, which is about \$488,000 per mile (Perry and Eliason, 2004). The U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL) estimates that more than 30 million tons of CO₂ from the Great Plains Synfuels Plant will be sequestered over the 35-year life of the EOR project. The injection of CO₂ into the depleted wells at the Weyburn oil field, which has boosted production by 27% (Burke, 2003), is expected to recover 155 million barrels of incremental oil by 2035 (U.S. Department of Energy [DOE], 2008a).

The Dakota Gasification Company financed the pipeline portion of the project, which brings in \$30 million in gross revenue annually from the sale of CO₂ (IEA, 2009a). At the production rate of 5,000 tons of CO₂ per day, the company is receiving \$16.43 per ton of CO₂ shipped. The U.S. Federal Energy and Regulatory Commission (FERC) set the rate of return for the project at 12.5% (Torp and Brown, 2005).

The EnCana Corporation financed the EOR portion of the project, which has a budget between \$1 and \$1.5 billion (Preston et al., 2004). The storage in Weyburn is estimated at \$20.04 a ton, and the EnCana Corporation purchases 5,000 tons per day (Torp and Brown, 2005). Over the 35-year life of the project, the corporation will spend \$1.28 billion for storage of CO₂ in the Weyburn oil field. At \$65 per barrel, the EnCana Corporation stands to gross over \$10 billion from incremental oil produced through the injection of CO₂ into depleted oil wells over the life of the project.

To ensure that the CO₂ stays in place once it is injected into the ground, the second phase of a two-phase monitoring project at the Weyburn oil field is underway. The monitoring project is a joint effort between public, private, and research entities, including the DOE (IEA, 2002). Phase I of the project, which concluded in 2004 (IEA, 2002) and cost \$28 million, predicted and assessed the suitability of CO₂ storage in depleted oil wells, as well as the economic feasibility of geologic sequestration (Preston et al., 2004). Specifically, the reservoir was studied to find seal integrity, potential leakage channels, and possible migration paths (Brown et al., 2001). Phase II of the Weyburn Carbon Dioxide and Monitoring Program, which began in 2005, is slated to conclude in 2010 (DOE, 2008a). Phase II, which will cost an additional \$40 million, 10% of which will come from the DOE, aims to assess risks associated with long-term CO₂ storage and to identify monitoring requirements to allay risks (DOE, 2008a). The five themes of Phase II include geologic integrity, wellbore integrity, storage monitoring methods, risk assessment and storage mechanisms, and data validation and management (DOE, 2008a).

Please note that the above economic analysis does not include the cost of the CO₂ separation system in the plant; it only includes the cost of compression and transportation costs.

Economic Analysis of Transport of CO₂

While the information given above clearly shows both the economic value and need for CO₂ for enhanced oil recovery on the Alaskan North slope, the proposed CTL plant at Eielson is located approximately 500 miles from the oil fields in Prudhoe Bay, and the CO₂ would need to be transported this distance before its value could be realized. Constructing a pipeline to handle the CO₂ could be undertaken, but only if the owners and operators of the pipeline were convinced that the returns on their investment would be positive. A positive return would require that two criteria are met: (1) that the cost of transporting the CO₂ is less than the value of the CO₂ on the ANS, and (2) that no other cheaper source of CO₂ is available for the operators of these oil fields.

There is a significant source of CO₂ already on the ANS, namely, the 12% CO₂ contained in the 35 Tcf (trillion cubic feet) of natural gas in the existing oil fields. If a gas pipeline were to be built, this CO₂ would need to be removed from the natural gas before its shipment to market, and thus would be available for use in EOR. If the proposed gas pipeline to East Coast markets were built with a capacity of 4.5 Bcf/day (billion cubic feet per day) of natural gas, this would result in the production of 0.54 Bcf/day of CO₂, which converts to approximately 33,100 tons per day. (This compares to the production of 14,560 tons per day from the smallest CTL plant proposed for Fairbanks.) The 35 Tcf of known gas reserves on the ANS would provide the same amount of CO₂ as the CTL plant would produce in about 50 years of operation.

Even though a significant amount of CO₂ is already on the ANS, using it for EOR still would require an investment by the oil and gas industry for separation, compression, and distribution within the field. There still may be a market for CO₂ from the CTL plant in Fairbanks if the cost of the pipeline to Prudhoe Bay is sufficiently inexpensive, or if the demand for CO₂ on the ANS is greater than what could be supplied by the existing inventory.

Another possibility might be the construction of a CTL plant directly on the ANS, to take advantage of the huge known coalfields that extend along the northern edge of the Brooks Range. This location would shorten the distance that coal and CO₂ would need to be transported, and would extend the life of the existing TAPS system by both providing a CTL product to be shipped and increasing the production from existing fields through EOR from CO₂ injection.

Carbon dioxide could also be used for EOR in Cook Inlet, but the oil fields there are much smaller than those on the ANS, and current operators have expressed reluctance to expose their aging offshore infrastructure to the potentially corrosive effects of CO₂. The Beluga coalfields are located near Cook Inlet, and CTL plants that have been proposed nearby would have the advantage of shorter pipelines and lower costs than the proposed Fairbanks CTL plant.

Enhanced Gas Recovery

Description of Technology

Depleted gas reservoirs are attractive options for carbon sequestration because the integrity of the formations is known. Carbon dioxide is injected into the permeable rock that holds the natural gas, and its escape is prevented by the same seal that prevented the natural gas from escaping for thousands of years. The injection of CO₂ increases pressure within the reservoir and can help recover incremental natural gas, which helps offset the cost of CO₂ capture and sequestration (Benson and Cook, 2005). However, if the reservoir is completely depleted of hydrocarbons, then the injection and sequestration of CO₂ yields no salable product to help offset the costs associated with the capture and storage of CO₂.

Current Demonstration Projects

K12-B CO₂ Injection Project. K12-B is a Dutch natural gas field in the North Sea, located about 93 miles northwest of Amsterdam and operated by Gaz de France Production Netherland B.V. The estimated capital expenditure for the project was 10 million Euros, and additional annual operations expenditures are estimated to be 1.4 million Euros (van der Meer et al., 2004). The K12-B CO₂ Injection Project re-injects CO₂ from the well that was produced for enhanced gas recovery (EGR). The gas field has been in production since 1987, and the natural gas produced from it has a high CO₂ content, 13% (TNO, 2007). The maximum allowable amount for market standards is 2.5% (TNO, 2007). Before 2004, the CO₂ stripped from the natural gas was vented; however, since 2004, 60,000 tonnes of CO₂ have been injected 4,000 meters underground into the nearly depleted K12-B gas field (TNO, 2007).

The goal of the project is to assess the feasibility of depleted gas fields as sites for the injection and storage of CO₂, as well as monitor and verify the site (van der Meer et al., 2006). As reported by van der Meer et al. (2006), the first test, which began in May 2004, injected 9,000 tons of CO₂ into well K12-B8, a completely depleted reservoir, over a period of 7 months. Well pressure was continuously measured from May to December of 2005. The injection caused the bottom-hole pressure to increase by nine bars over the monitoring period. Despite the low average pressure displayed by the reservoir rock, injectivity was good. The models used accurately predicted the outcome of the test.

The second test began in February 2005, when CO₂ was injected into an actively producing reservoir. Two producing wells, K12-B1 and K12-B5, and one CO₂ injection well, K12-B6, were under investigation. Two tracers, which allow for the monitoring of the CO₂ plume, were injected at the beginning of the second test (van der Meer et al., 2006). Tracers also allow for the distinction between injected CO₂ and the naturally occurring CO₂ within the natural gas (TNO, 2007). The CO₂ injection rate and its purity, the composition of produced gas, the integrity of CO₂ injection tubing, and the cement bond quality of the

injection well were measured, and temperature and pressures at various points in the process were monitored (TNO, 2007). There were unexpected pressure differences between the injection and production wells, which have not been explained, and monitoring of the site continues (TNO, 2007). The injection of CO₂ did not improve the gas-production, and it was concluded that continued injection was needed to realize EGR (van der Meer et al., 2006).

Injection in Saline Aquifers

Description of Technology

Saline aquifers are deep brine-bearing sedimentary formations with no economic value. The high-salinity formation water is not potable and cannot be used for agricultural purposes (Bachu and Adams, 2003). According to Bachu and Adams (2003), whose work provides the information on this technology, a geologic formation used for CO₂ sequestration must be overlain by an impermeable seal to prevent the vertical migration of CO₂ or brine water, which could potentially contaminate fresh water sources. The formation must also be porous and permeable to facilitate the injection of CO₂. Deep saline formations are widespread and have a large potential capacity for CO₂ storage, estimated at 1,000 gigatonnes. When CO₂ is injected into the formation, it displaces the brine water in the pore spaces. Carbon dioxide has three means of sequestration within the formation: It can be trapped by dissolution into the formation water, it can react chemically with the surrounding fluids and rocks to form stable carbonate minerals, or it can be sequestered through hydrodynamic trapping. Upon injection, the CO₂ will dissolve into the brine water up to the saturation point; mineral precipitation will also take place. Any additional CO₂ that is not trapped by dissolution or mineral precipitation will flow in a buoyant plume until it eventually smears itself out, or escapes back into the atmosphere. Mineral trapping is the most promising form of sequestration, because it permanently removes CO₂ from the atmosphere once the chemical reaction takes place; however, the chemical reaction, in the form of carbonate precipitation, is slow. Chapter 1 provides a discussion of the locations of potential saline formations in Interior Alaska.

Current Demonstration Projects

Statoil's Sleipner Natural Gas Field. Statoil's Sleipner natural gas field is an offshore gas field located in the center of the Northern Sea. In order to avoid an initial carbon tax of 320 NOK/t (Norwegian kroner per ton), Sleipner began injecting the CO₂ stripped from the natural gas into an underground saline aquifer, the Utsira Formation (Torp and Brown, 2005). Torp and Brown (2005), whose study provides much of the information for this section, report that the natural gas produced at Sleipner is 9% CO₂; therefore, a portion of the CO₂ has to be stripped out of the natural gas in order to meet sales specifications of 2.5% CO₂. Instead of releasing the CO₂ to the atmosphere, Statoil has injected it into the ground since 1996. Amine is used to separate the CO₂ from the gas

stream. The separation takes place on the treatment platform with two absorption towers and an amine regeneration facility. After separation, the CO₂ is compressed in stages to 80 bar, cooled to 40°C and injected 1,000 meters below sea level into the vast Utsira Formation, which is expected to hold 25 megatonnes (Mt) CO₂ over the expected 25-year life of the field. At 1000 meters, the supercritical CO₂ is still buoyant. Simulations were performed and predicted that the CO₂ would migrate vertically through the permeable layer until it hit the thick impermeable shale above; then it would migrate laterally. The CO₂ is injected into a lateral well that deposits the supercritical CO₂ into the Utsira Formation 4 kilometers away from the platform to avoid corrosion of the production wells below the Sleipner platforms. One million tons of CO₂ are sequestered annually from the Sleipner field (IEA, 2009b). Releasing the CO₂ from Sleipner into the air would have increased Norway's CO₂ emissions by 3% (IEA, 2009b).

Sequestering the CO₂ added additional cost to the Sleipner operation. Torp and Brown (2005) report the following figures: Estimated costs for the preparation work for the sequestration project including seismic surveys, coring, well logs, and reservoir simulations is \$1.9 million. The 4-unit compressor train cost an estimated \$79 million. The tubing for the lateral well is made of 25% chromium duplex steel to protect against corrosion. The cost of the drilling and completion of the well is estimated at \$15 million. Additional operational costs associated with carbon capture and sequestration are estimated at \$7 million. The cost of additional capital sums is estimated at \$96 million. The additional operational costs accumulated since 1996 are an estimated \$84 million. Although the total project costs an estimated \$180 million, Statoil has avoided paying taxes on its carbon emissions (Torp and Brown 2005). As of 2008, Norway's carbon tax was \$66 USD per ton of CO₂ emitted (AFP, 2008). Sleipner avoided \$66 million in carbon taxes last year (AFP, 2008). High carbon taxes served as an economic incentive for Statoil to sequester the CO₂ produced at Sleipner.

Frio Brine Pilot. The University of Texas's Bureau of Economic Geology (BEC) and partners, including several national laboratories, conducted the Frio Brine Pilot, a geological sequestration pilot project in South Liberty field, Dayton, Texas (Airhart, 2006). The DOE NETL funded the \$5.75 million project that ran from 1998 to 2008 (DOE, 2008b). In October of 2004, 1,600 tons of CO₂ were injected into the porous, permeable, brine-bearing sandstone formation 1,500 meters below the surface (DOE, 2008b). The CO₂ was shipped to the site in a supercritical state, but was then returned to a gaseous state for injection (Airhart, 2006). The second phase of the project was carried out from 2006 to 2007, during which time an additional 250 tons of CO₂ were injected into the formation (DOE, 2008b). The CO₂ plume was closely monitored over the following year (DOE, 2008b). Overall, 1,750 tons of CO₂ were injected at the test site over the life of the project.

The project was designed to test modeling, monitoring, and verification techniques for CO₂ injection sites, as well as to garner public acceptance for carbon sequestration (DOE,

2008b). For the test, a monitoring well was set up 100 feet from the preexisting injection well (Airhart, 2006). Once the CO₂ plume spread to the monitoring well, frequent multiphase fluid samples were taken through a bottomhole sampler, called the U-tube (DOE, 2008b). Various instruments were used to monitor the movement of the CO₂ plume after injection, including wireline saturation logs, and cross seismic and downhole pressure and temperature monitoring (Hovorka et al., 2006). The results from the tests were used to validate models that predict changes in the CO₂ plume and its movement (Hovorka et al. 2006). Brine becomes acidic when exposed to CO₂, and acidic brine can dissolve a portion of the surrounding rock and minerals with which it comes in contact (Airhart, 2006). It is necessary to monitor CO₂ plumes after injection to ensure that the CO₂ does not leak into fresh-water aquifers used for drinking or escape into the atmosphere (Airhart, 2006).

The Frio Brine pilot test will serve as a model for carbon sequestration in the southeastern United States, where 16% of the nation's total CO₂ emissions from point sources is produced (Hovorka et al., 2006). This region of the United States has been identified as a potential candidate for CO₂ sequestration because of its large volume of thick, porous high-permeability sandstone formations with shale seals above and below the formation (Hovorka et al., 2006). These brine-bearing sandstone formations have an estimated capacity of 222 Gt for CO₂ storage (Hovorka et al., 2006). When CO₂ is injected into a brine-bearing saline formation, it dissolves into the brine with a residual CO₂ saturation of approximately 20% (Hovorka et al., 2006). The remaining 80% continues to move outward to the pores in the surrounding rock until the plume eventually smears itself out (Airhart, 2006). The project was completed in 2008 (DOE, 2008b).

In Salah CO₂ Joint Industry Project, Algeria. BP, Statoil, and Algeria's state oil company, Sonatrachi, are partners in the \$2.7 billion In Salah Gas Project that began in 2004, according to Knott (2008), whose report was used for this section. The CO₂ sequestration portion of the project called the In Salah CO₂ Joint Industry Project (JIP) cost \$100 million. Assurance research and development to monitor the CO₂ cost \$30 million. The Krechba, Tregentour, and Reg fields in the Algerian Desert, with reserves of 160 Bscm (billion standard cubic meters) of natural gas, were developed. Natural gas from the Tregentour and Reg fields is piped 120 kilometers north to a central processing facility at Krechba. The natural gas from the three fields contains an average of 5.5% CO₂, and in order to meet the market standard of 0.3% CO₂, an amine process strips a portion of the CO₂ from the natural gas. The CO₂ is compressed for reinjection to a pressure of 185 bar by 2 four-stage compressors. Annually, approximately 1 million tons of CO₂ are reinjected 2 kilometers deep into the low-permeability Krechba sandstone reservoir. The clean natural gas is piped 455 kilometers to Hassi R'Mel, where it is compressed and then shipped 5 kilometers to the country's gas-distribution hub for distribution to Europe. BP estimates

that over 17 million tons of CO₂ will be sequestered instead of released into the atmosphere over the 25- to 30-year life of the project.

The Krechba reservoir is 20 kilometers by 5 kilometers with 4 production wells in the gas-bearing portion of the formation. Three CO₂ injection wells were drilled in the saline-bearing portion of the formation, which is 5 kilometers down-dip from the gas-bearing portion of the formation. Over time, the CO₂ plume will migrate into the up-dip portion of the formation that currently holds natural gas; however, this migration will occur slowly and should occur after the field's natural gas reserves are depleted.

The JIP is a partnership between industry, academia, non-governmental and governmental organizations. It has three objectives: (1) to demonstrate cost-effective, long-term assurance that CO₂ sequestration can be verified through short-term monitoring techniques, (2) to demonstrate viability of CO₂ sequestration as a CO₂ mitigation option, and (3) to set precedents for future storage and verification of CO₂ sequestration. Initially, over 20 techniques were experimented with for monitoring. After experimentation, the emerging monitoring technique was a satellite imaging technique referred to as *interferometric synthetic aperture radar* (InSAR), which uses electromagnetic radiation to produce images of changes in surface deformation over time. Between 2004 and 2007, InSAR detected changes in the surface level of the Krechba formation. Some areas have remained stationary, while other areas have risen by as much as 15 millimeters; still other areas have decreased by 5 millimeters. It is unclear whether the injection of CO₂ caused the changes. Another monitoring technique employed at the site is 3D seismic imaging. In 2009, a \$9 million 3D seismic survey will be conducted and compared to the baseline survey that was conducted in 1997. This seismic survey will show the migration of the CO₂ plume. A third set of monitoring techniques include wellhead fluid sampling, tracers, and pressure analysis. The field's 7 active wells are monitored continually. An additional 7 wells from previous operations are used for data collection every few weeks. Thus far, CO₂ has not been detected at the new wells; however, CO₂ was detected in one of the inactive wells. Because unique tracers are injected along with CO₂ at each injection well, it is known from which well the CO₂ originated. Additional monitoring includes a microseismic listening technique, which is used to detect small movements in the rock that could occur because of CO₂ injection. This method involves drilling shallow holes of 500 meters and suspending geophones for sound detection. Several other monitoring techniques are planned for the site, including soil gas surveys and the observation of a shallow aquifer that flows 100 meters below the surface at Krechba.

CO₂SINK Integrated Project, Ketzin, Germany. The CO₂ Storage by Injection into a Natural Saline Aquifer at Ketzin (CO₂SINK) is a CO₂ sequestration demonstration pilot in Ketzin, Germany, and is the first onshore demonstration in Europe. According to Schilling et al. (2009), upon whose report this information is based, the project is coordinated by the German Research Center for the Geosciences (GFZ) and has 18 partners from 9

different European nations. The project, which began in 2004, includes 1 injection well and 2 observation wells, each with depths of 750–800 meters. Various instruments were installed to monitor the CO₂ plume, including distributed temperature sensor optical cable and 45 permanently installed downhole sensors. The 80-meter thick Stuttgart Formation—the target injection formation composed of layers of sandstone, siltstone, and mudstone—has a temperature of 35°C at the 650-meter injection depth. Coring, well logs, hydrological tests, and a 3D seismic survey were conducted to maintain information about the formation.

Injection began on June 30, 2008, and a maximum of 60,000 tons will be injected over the life of the project. The CO₂, which is trucked to the injection site by an industrial gas supplier, is injected in a supercritical state, but turns into a gas when exposed to the temperature and pressure of the formation. Tracers are added to the CO₂ to monitor the migration of the plume, and the temperature within the well is monitored to determine if the CO₂ is in a supercritical, fluid, or gaseous state. Geo-electrical monitors are used to determine CO₂ saturation, and a fiber optic pressure sensor takes real-time pressure data. Geochemical and microbial investigations are conducted to determine the effect of the CO₂ on the reservoir. Numerical models are continually updated to match the geological models.

Appalachian Basin Geologic Test at R.E. Burger Power Plant. The R.E. Burger Power Plant is located near Shady Side, Ohio, along the Ohio River. The 413 MW plant, built in the 1940s by Ohio Edison, is currently operated by FirstEnergy (DOE, 2008c). The sequestration pilot was a joint effort between the DOE NETL, FirstEnergy, and the Ohio Geological Survey. The DOE funded \$17.5 million of the \$23.7 million project cost. The purpose of the pilot was to assess the feasibility of CO₂ sequestration in the deep saline reservoirs of the sedimentary Appalachian Basin. This area is of interest because it is the location of numerous coal-fired power plants. The Appalachian Basin spreads across Ohio, Pennsylvania, Maryland, Kentucky, and West Virginia. The target for injection was the Oriskany and Clinton Sandstones, with depths ranging from 5,500–8,000 feet (Jacobs, 2009). Site preparation for the injection included an assessment of the geology, a seismic survey, and test well drilling. Monitoring of the injection proved difficult because the nearest well beyond the injection well was 20 miles away (Jacobs, 2009). Drilling another well solely for monitoring the injection site proved too expensive for such a small pilot; therefore, all monitoring took place from the injection well. In September 2008, the Ohio EPA issued an Underground Injection Control (UIC) permit. Carbon dioxide was transported to the site via trucks, and heated to wellhead conditions. Between 1,000–3,000 metric tons of CO₂ were to be injected at a rate of 240–2,400 tons per day over several months. The target formations were found to have lower porosity and permeability, and have less void space than expected (Jacobs, 2009). When injection began, the pressure in the formation rose higher than expected, and injectivity was compromised (Jacobs, 2009).

Nagaoka Project, Japan. The Minami-Nagaoka demonstration project in Japan is conducted by the Research Institute of Innovative Technology for the Earth in conjunction with the Engineering Advancement Association of Japan. Information on this project was based on the work of Tanase and Yoshimura (2008). Injection began in July 2003 and ended in January 2005, during which 10,400 tons of CO₂ were injected in the Minami-Nagaoka gas field in Nagaoka City. One injection well and 3 observation wells were used for the project. Supercritical CO₂ was injected at a rate of 20–40 tons per day into a permeable sandstone formation 1,100 meters below the surface. For monitoring purposes, time-lapse well logging, seismic tomography, fluid sampling, and continuous bottomhole temperature and pressure measurements were used.

Economic Analysis

As can be seen from the Sleipner example, described earlier, the motivation for sequestering CO₂ in saline formations is to avoid taxes on the release of carbon. However, for the Fairbanks CTL project, this method might require a shorter pipeline than the EOR applications to the Alaska North Slope, and might be a lower-cost alternative.

Injection into Unmineable Coal Seams

Description of Technology

Deep unmineable coal seams are good candidates for carbon sequestration because CO₂ can be stored in coal seams that are either too deep or too thin to mine economically. Methane recovered from coal can partially offset the costs associated with the capture and storage of CO₂, using a process called CO₂-enhanced coalbed methane recovery (CO₂-ECBM) (Shi and Durucan, 2005). Traditional coalbed methane (CBM) recovery should take place before CO₂-ECBM is attempted (J.Q. Shi, personal communication, August 23, 2009). Traditional CBM depressurizes the coal seam by dewatering, which then allows CH₄ (methane) to be recovered (J.Q. Shi, personal communication, August 23, 2009).

According to Shi and Durucan (2005), whose work provided the information for this section, coalbeds have cleats—natural fractures in the coal—between which are matrix blocks containing porous structures. Gasses are stored in coal through adsorption onto the surfaces of the coal, absorption within its molecular structure, and with its pores and cleats. Coal has a greater affinity to CO₂ than CH₄. When CO₂ is injected into the coal seam, CH₄ is desorbed from the coal and is replaced by CO₂, which adsorbs to the coal. Coal can adsorb at least twice as much CO₂ as methane, with some low-rank coals adsorbing 10 times more CO₂ than methane. Thus, unmineable coal seams are a potential carbon sink. It is estimated that coalbeds in the United States have a storage capacity of 90 Gt CO₂. Chapter 1 provides additional discussion of this technology as well as a description of the locations of coal-bearing formations in Interior Alaska.

Current Demonstration Projects

Coal-Seq. Coal-Seq is an enhanced coalbed methane-recovery pilot project in the San Juan Basin in northern New Mexico and southern Colorado. Partially funded by the DOE, the project operated from 2000 to 2008 and cost \$7.39 million (DOE, 2008d). The DOE contracted with Advanced Resources International to launch the pilot project, which involved two pilot field tests (Reeves et al., 2004). Carbon dioxide was injected into the Allison Unit to assess ECBM recovery properties with CO₂, and nitrogen (N₂) was injected into the Tiffany Unit to assess ECBM recovery properties with nitrogen (DOE, 2008d). Because N₂ is the primary constituent of flue gas, interest is great to learn whether it can be used in ECBM recovery projects (DOE, 2008d), as using it would prevent the need to separate CO₂ from flue gas (an energy-intensive and expensive process) before injection into the coal seam.

The information that follows on the Allison Unit is based on a paper by Reeves and Oudinot (2005). The Allison Unit, operated by Burlington Resources, began producing methane in 1989. Carbon dioxide injections for enhanced methane recovery began in 1995 and continued throughout 2001. The CO₂ was transported 36 miles via a 4-inch \$3.6 million pipeline. Approximately 1 unit of methane was recovered for every 3 units of CO₂ injected into the production field. The pilot was composed of 16 production wells, 4 CO₂ injection wells and a monitoring well. The CO₂ injections helped recover 17–18% of original-gas-in-place. The injection of CO₂ into the coal caused the seam to swell and reduced permeability, which reduced injectivity and therefore reduced incremental methane recovery. The project was uneconomic, not considering tax benefits, at the prevailing gas price of approximately \$2.20/Mcf at the time the pilot was conducted. However, economic modeling showed a breakeven price of approximately \$2.60/Mcf (Reeves and Oudinot, 2005).

Information on the Tiffany Unit is based on a topical report by Reeves and Oudinot (2004). The Tiffany Unit, operated by BP America, began producing methane in 1983. Nitrogen injections for enhancing methane recovery began in 1998 and continued intermittently throughout 2002. The pilot included 34 production wells and 12 nitrogen injection wells. Nitrogen was transported 16 miles via a 12-inch \$4.6 million pipeline from a cryogenic air separation plant at the Florida Rive gas processing facility. Approximately 1 unit of methane was recovered for every 0.4 units of N₂ injected, which is to say, N₂ is more effective for methane recovery than CO₂. However, N₂ injection does not possess any carbon sequestration benefits. Adding nitrogen to the CO₂ stream for future CO₂ sequestration ECBM recovery projects will improve incremental methane recovery. For the pilot project, the N₂ injections helped recover 20% of the original-gas-in-place. The N₂ injection pilot was also uneconomic, not taking into account tax benefits, during the time of the pilot test at the prevailing gas price of \$2.20/Mcf.

Although the Coal-Seq projects were not profitable, useful information about ECBM recovery was collected during the pilot. An integrated technical and economic model was created for use on future ECBM recovery projects (DOE, 2008d). High-rank, low-permeability coal seams are ideal for ECBM recovery because of the assumption that deep, low-permeability coal seams have not been used previously for conventional coalbed methane recovery (Reeves et al., 2004). In the future, CO₂ sequestration may be accomplished at a slight profit (DOE, 2008d), although issues related to injectivity decline and reduced coal permeability with the injection of CO₂ must be overcome (Reeves et al., 2004).

Economic Analysis

Injecting CO₂ into unmineable coal seams might be possible in Healy, which would require a shorter pipeline than for the EOR projects to the North Slope. If injecting CO₂ requires first removal of the methane, this might be used in Healy, or for power generation. However, a pipeline would be required to move the CO₂ from Fairbanks to Healy.

Discussion of Other Possible CO₂ Sequestration Methods

Chemical Reaction with Mafic Rock

Carbon dioxide in the atmosphere naturally reacts with the iron and magnesium found in volcanic rocks, to form carbonates. Carbonates are eventually carried to the seas, where they are used by living organisms to form shells, or where they precipitate to form limestone, in which most of the carbon on earth is stored. This mechanism has been responsible for reducing the atmospheric levels of CO₂ over geologic time by a factor of 20 over the last 600 million years. However, the reaction rates for these processes are slow. The level of decline just described amounts to about 1 ppm (parts per million) decrease in CO₂ over a period of 100,000 years, while the current increase in CO₂ levels has been measured at about 1 ppm per year.

The major problem with using the mechanism of chemical reaction with mafic rock for the storage of CO₂ is the slow reaction rate, especially with natural processes with CO₂ at atmospheric concentrations, pressures, and temperatures. Research is being conducted into finding ways of accelerating the reaction rates, including increasing the pressure and the temperature of the reactants. Mixing with water and injecting at high pressure into porous rock layers adjacent to mafic rock has been shown in the laboratory to speed reaction rates. Chapter 1 provides additional discussion of this technology as well as a description of the locations of mafic rocks in Interior Alaska.

Current Demonstration Projects

Basalt Sequestration Pilot Test. The Basalt Sequestration Pilot Test is a carbon sequestration project in Walla Walla County in eastern Washington. The \$6.2 million project is funded by the DOE NETL and Pacific Northwest National Laboratory, as well as Idaho State University, Idaho National Lab, Boise White Paper L.L.C., Shell Oil Company, Port of Walla Walla, and Portland General Electric (DOE, 2008e). The small-scale pilot aims to sequester CO₂ deep in the Columbia River Basalt Group, a deep basalt formation in the Pacific Northwest (Big Sky Carbon Sequestration Partnership [BSCSP], 2009). The storage capacity of the Columbia River Basalt Group is an estimated 50 to 100 Gt of CO₂ (BSCSP, 2009). Basalt, a volcanic rock, is an attractive choice for CO₂ sequestration because CO₂ reacts with the cations in the rock to form carbonate minerals. Once chemical alteration occurs and minerals form, CO₂ is permanently trapped in the rock and cannot leak into the atmosphere (BSCSP, 2009).

In 2007, a seismic survey was conducted to determine the subsurface geology of the site, during which shallow soil gas probes were installed to test for anomalies in the gas composition of the soil (DOE, 2008e). The basalt formation was studied to find the thickness and permeability of its layers, and water samples were taken (BSCSP, 2009). The basalt formation is layered, containing dense, hardened lava layers and layers that are more porous. The harder layers will serve as a seal for the permeable porous layers below it that will be injected with CO₂. The impermeable seal layer will prevent CO₂ from migrating upward toward the surface. Once CO₂ is injected into the porous layers, it will mix with the water in the pores of the rock and, in time, will harden into calcium carbonate, at which point the CO₂ will be permanently sequestered in the formation (BSCSP, 2009). In early 2009, drilling for the injection well began; from this well, subsurface hydrology and geologic data can be analyzed (BSCSP, 2009). For the pilot test, 1,000 tons of supercritical anthropogenic CO₂ will be injected into the formation over a two-week period during the summer of 2009 (BSCSP, 2009). The CO₂ will be injected at a depth between 4,100 feet (P. McGrail, personal communication, April 6, 2009), a depth far below potable water sources. The site will be monitored for 12 to 15 months after the CO₂ is injected (Hillhouse, 2009). Scientists expect the CO₂ will mineralize within two years of injection (DOE, 2008e).

CarbFix Project, Iceland. The CarbFix project was launched in 2007 as a pilot to assess the feasibility of basalt sequestration (Matter et al., 2009). CarbFix is a joint project between Orkuveita Reykjavíkur, The University of Iceland's Institute of Earth Sciences, Columbia University's Lamont-Doherty Earth Observatory, and France's Centre National de la Recherche Scientifique (Sigurdardottir, 2008). The project has an estimated total cost of \$4.3 million dollars through 2010 (Sigurdardottir, 2008). Basalt sequestration is of interest in Iceland, because 90% of the nation is made up of basalt rock (CarbFix, 2009). The Hellisheiði Geothermal Power Plant, a geothermal combined heat and power plant

located on a volcanically active ridge in southwest Iceland, currently has a capacity of 213 MW (Orkuveita Reykjavikur, 2009). The plant plans to expand its capacity to 300 MW of electricity and 400 MW of thermal production (Orkuveita Reykjavikur, 2009). The plant currently emits up to 30,000 tons of CO₂ annually, and this number will increase as the plant expands capacity (Matter et al., 2009). Carbon dioxide makes up less than 1% of the plant's steam emissions (Matter et al., 2009). A pilot gas processing plant will separate the geothermal gases from the emission stream, and the CO₂ along with 2% hydrogen sulfide will be injected into a basalt aquifer (Matter et al., 2009). The project includes one 2,000-meter injector well, along with several 100–1,400-meter observation wells (Matter et al., 2009). The target formation is made up of lava flows and hyaloclastite at a depth of 400–800 meters and has a temperature range of 30–50°C (Matter et al., 2009). The CO₂ gas will be fully dissolved into water for injection to create an aqueous solution, which is necessary for the mineral carbonation chemical reaction (Matter et al., 2009). This is a water intensive process (Matter et al., 2009). At the required temperature and pressures for injection, the dissolution process requires 27 tons of water per 1 ton of CO₂ (Matter et al., 2009). Once injected, the CO₂ will react with calcium in the basalt and form a stable mineral, calcite (CarbFix, 2009). Injection is set to begin in 2009 and will continue for 6 months (Matter et al., 2009). The basalt formation is layered with both porous permeable layers and nonporous impermeable layers (Matter et al., 2009). The porous, permeable layers will be injected with CO₂, while the nonporous impermeable layers will serve as a barrier for vertical migration of CO₂ (Matter et al., 2009). The target formation has undergone multiple geological and hydrological tests to gain a better understanding of its properties; results of these tests show that there is a large surface area within the target formation for the chemical reaction to take place (Matter et al., 2009). Once the CO₂ is injected, monitoring and verification tests will be conducted (Matter et al., 2009).

Storage in Hydrate Structures Under Permafrost

Carbon Sequestration Beneath Permafrost: Enhanced Gas Hydrate Recovery

Gas hydrates are clathrate compounds in which a guest gas molecule is encased in an ice-cage lattice made of frozen water molecules (White and McGrail, 2009). Gas hydrates are naturally occurring in Arctic regions beneath permafrost and beneath the seafloor within sediments along continental margins; they form in the hydrates stability zone at low temperatures and high pressures where hydrate-forming gases are available (Collett, 2009). Gas hydrates are of interest because hydrate deposits store large volumes of methane, the cleanest fossil fuel. Additionally, CO₂ can be sequestered during the methane recovery process from gas hydrates. It is possible to store CO₂ as a solid hydrate compound in the pores of subsurface permafrost sedimentary rocks for geologic time periods with each volume of hydrate capable of storing up to 175 volumes of gas (Jadhawar et al., 2006).

The process for sequestering CO₂ in gas hydrates involves injecting CO₂ into the hydrate-bearing formation (White and McGrail, 2009). Some of the methane in the hydrates is displaced by CO₂, and this process transforms simple CH₄ (methane) hydrates into either simple CO₂ hydrates or double CH₄-CO₂ hydrates (White and McGrail, 2009). The re-occupation of pores with CO₂ hydrate maintains the mechanical stability of the formation, and the displaced methane is recovered and sold, which helps offset the cost associated with the capture and sequestration of the CO₂ (White and McGrail, 2009).

There are two methods for methane recovery from gas hydrates: One method is dissociation of the clathrate hydrate yielding water and methane and the other method is replacement of the methane molecule with another guest molecule (White and McGrail, 2009). Dissociation of the clathrate can be achieved either by heating the clathrate to a temperature above its stability point, or by depressurization, whereby the pressure is lowered below the stability point (White and McGrail, 2009). Injection of an inhibitor compound yields methane by decreasing the equilibrium temperature of the hydrate (White and McGrail, 2009). The injection of CO₂ falls into the inhibitor injection category.

Complications can occur from the production of gas hydrates. If the hydrates at the base of the hydrate stability zone decompose, landslides can occur because of the decreased stability of the land (Jadhawar et al., 2006). In addition, there is risk of a release of huge amounts of methane if the hydrate seal is broken. Methane is a potent greenhouse gas. Decomposition of hydrates can also destabilize the foundations of drilling platforms and production wells (Jadhawar et al., 2006). On land, subsidence could result from the decomposition of hydrates (Jadhawar et al., 2006). Chapter 1 provides additional discussion of this technology as well as a description of the locations of gas hydrates in northern Alaska. No gas hydrates occur in Interior Alaska.

Current Demonstration Projects

Two pilot tests for methane recovery from arctic onshore gas hydrates beneath permafrost have been conducted. The first pilot was the Mallik 2002 Gas Hydrate Production Research Well Program in Canada's Mackenzie Delta (Geological Survey of Canada, 2003). The USGS, USDOE, Canada, Japan, India, Germany, and the energy industry participated in the pilot. An additional pilot project was the 2007 Milne test, which was a partnership between the USGS, USDOE, and BP on the North Slope of Alaska (BP Global, 2007). The purpose of both pilots was to assess the technical and economic feasibility of methane recovery from gas hydrates. Neither project tested the injection of CO₂ to displace methane. Currently ConocoPhillips is collaborating with the DOE to assess methane recovery from gas hydrates while sequestering CO₂ (DOE, 2009a). This field test—the first of its kind—will test the technology that has been used in laboratories to replace methane molecules enclathrated in gas hydrates with CO₂ molecules while recovering the methane. The project has a budget of roughly \$14.7 million, of which DOE funds \$11.75 million (DOE, 2009a).

Injection Under Permafrost

It has been suggested that CO₂ could be stored under permafrost. This suggestion is from the Fairbanks Energy Task Force report (Fairbanks Energy, 2007, page 10), which states

One option which is naturally considered in a cold climate such as Alaska is the integrated cascade chiller, which is a conceptual design proposed by Clodic et al. of Ecole des Mines de Paris, at the Greenhouse Gas Control Technology 6 Conference. Chilling of the gas to -120°C solidifies the water and the carbon dioxide, depending upon the pressure. In an Alaskan application, the storage of such a frost mixture or of a carbon-dioxide-based gas hydrate in an underground cavern could be considered. Of course, the simple separation of the water vapor at modest negative temperatures, followed by injection of carbon dioxide gas into an available porous geological stratum, would be even more economical. Clearly, conceptual research on these possibilities is needed.

The Clodic reference cited above does not refer to the burial of CO₂ in solid form; it instead discusses the use of the formation of solid CO₂ (dry ice) as a method of carbon capture. However, Salem Esber, a student at MIT, noted on page 30 of his thesis (Esber, 2006) that this method has proved impractical to date. There are several references to the injection of CO₂ under permafrost in the Russian literature (Lombardi et al., 2006), but this storage method depends strongly on thick continuous permafrost acting as a physical barrier to the escape of the CO₂. It is not clear if such a method would be a suitable mechanism in the Fairbanks area, where the permafrost is both thin and discontinuous.

Deep Ocean Storage

The direct injection of CO₂ into the ocean has been proposed as a CO₂ mitigation strategy. Supercritical CO₂ released on the bottom of the ocean forms a lake that is encased in CO₂ hydrate (Tsouris, 2004). However, this method has negative effects on benthic sea life, because the dissolution of the CO₂ depletes the seawater of oxygen in the injection area (Tsouris, 2004). Another method of CO₂ ocean sequestration uses a continuous-jet hydrate reactor (CJHR), developed by Oak Ridge National Laboratory, to make CO₂ hydrate particles (Szymecek, 2008). A clathrate hydrate is a stable formation of gas molecules enclosed in an ice-cage of water molecules (Szymecek, 2008). The CJHR mixes liquid CO₂ with water under pressure to form hydrate particles (Szymecek, 2008). Hydrate particles that are dense enough to sink at shallower depths are desired, because the cost associated with ocean sequestration increases as the depths at which the CO₂ is deposited increases (Szymecek, 2008). In addition, denser hydrate particles dissolve more slowly (Tsouris, 2004). At ambient temperatures and pressures typically found in the ocean at depths greater than 1,000 meters, particles made of a composite paste of liquid

CO₂, CO₂ hydrate, and water are denser than water and sink, therefore (Tsouris, 2004). In experiments conducted by the Monterey Bay Aquarium Research Institute, even at depths below 1,000 meters the hydrate particles were positively buoyant or neutral as they dissolved (Tsouris, 2004).

Deep ocean storage as a method of sequestration has ecological complications. Injecting CO₂ into the ocean will lower the pH of the water and, therefore, increase the acidity of the water (Tsouris, 2004). Carbon dioxide levels in the ocean have increased since the industrial age because the ocean naturally absorbs CO₂. Ocean acidification is a problem because it depletes the carbonic acid available in the water for creatures to build carbonic shells. In lab tests, injecting CO₂ into water weakened or dissolved the carbonic shells of sea creatures. Increased levels of CO₂ in ocean water could disrupt the food web and, therefore, disturb the ocean ecosystem.

Feasibility of Large-Scale CO₂ Ocean Sequestration

The Monterey Bay Aquarium Research Institute (MBARI). The MBARI developed an oceanic sequestration pilot project in Monterey Bay off the coast of California that began in 2000. The project cost \$1.59 million dollars, of which \$1.23 million was funded by DOE. Information from a report by DOE (2008f) was used for this section of the report. The Monterey Bay Aquarium Research Institute collaborated with the University of Washington at St. Louis to inject and monitor the physical, biological, and chemical behavior of liquid CO₂ in the deep ocean to investigate the fundamentals of ocean sequestration. Remotely operated vehicles (ROVs) were used to monitor the small amounts of CO₂ that were released onto the ocean at depths down to 3,600 meters. In situ Raman spectroscopy was used to analyze the interaction between the CO₂ hydrates and the surrounding ocean fluids and sediments. Five dives were executed, depositing no more than 280 liters of CO₂ at different depths. Below a depth of 3,000 meters, the CO₂ reacted with the surrounding water and turned into a solid hydrate, because the density of CO₂ exceeds the density of saltwater at this depth. The CO₂ created a complex set of biological responses and lowered the pH of the surrounding water plume.

Ejecting CO₂ Out of the Atmosphere Along Magnetic Field Lines

Dr. Alfred Wong, a scientist at University of California, Los Angeles, has researched ionizing CO₂ particles and ejecting them from the atmosphere at the Earth's northern pole, where the magnetic shield opens into outer space. Wong's research has been reported in an article entitled "A Stairway to Heaven" (2007), upon which the information in this section is based. Wong has conducted ionization experiments at the High Power Auroral Stimulation (HIPAS) facility near Fairbanks, Alaska, a facility that was used originally to stimulate artificial auroras. According to Wong, because the magnetic shield opens, particles can move in and out of the atmosphere (Wong, 2007). The aurora is an

example of the sun's particles breaching the magnetic field and hitting the atmosphere. The ejection of oxygen from the atmosphere at the poles has been observed from space, and Wong theorizes the same can be done with ionized CO₂ particles.

Carbon dioxide particles form negatively charged CO₂ ions when they pair with electrons; when the CO₂ ions hit the Earth's vertical electric field, the ions drift upward. At an altitude of approximately 125 kilometers, the spinning motion of the ions begins to slow, and the spinning motion is converted to an upward motion until the ions are ejected from the atmosphere. Wong hopes to increase the magnitude of this naturally occurring phenomenon to rid the atmosphere of enough CO₂ to slow the effect of climate change. Wong proposes using powerful lasers to release electrons into the atmosphere that will bond with CO₂. Once the CO₂ ions form and drift to 125 kilometers, he will use radio waves to spur the spiraling that will eventually eject the ions out of Earth's atmosphere into outer space. Although Wong admittedly does not know exactly how much CO₂ will be ejected from the atmosphere, he believes he can eject not only more CO₂ than he generates in the ejection process with his diesel-powered laser beams and radio transmitters, but enough to make a significant dent in the amount of CO₂ in the atmosphere. However, at this time, there is no way to measure the amount of CO₂ ejected.

There are several problems with Wong's approach. The first and most obvious problem is the energy required to power the antenna array, which is needed to provide the energy to ionize the CO₂ molecules in the upper atmosphere. The HIPAS facility currently uses 2 larger locomotive-size diesel engines to power the antenna array. Each of these is a 2.2 MW generator. Assuming that the generators are operating at full power, that they get 12 kW hours per gallon of diesel fuel (about right for engines of this vintage), and that burning 1 gallon of diesel fuel produces about 19.2 pounds of CO₂, this diesel engine array will consume about 366 gallons of fuel per hour and produce about 7,040 pounds of CO₂ in that time, or about 3.5 tons per hour. This CO₂ will be released into the atmosphere. It appears that Al Wong avoids this emission by using nuclear power for his energy source—a convenient dodge of the reality of how energy-intensive this method is.

It is difficult to estimate how much CO₂ could be ejected from the upper atmosphere during a 1-hour period, but the densities in the upper atmosphere are not very high. The following calculation is based on the mass of air in the ionosphere directly above the antenna array, starting at the bottom of the ionosphere, which begins at about 50 kilometers above the surface of the earth. Using the rule of thumb that the atmospheric pressure decreases by half for every 5.6 kilometers, the pressure at 50 kilometers is 0.205% of that at the surface, which means that the total atmospheric mass above this level is the corresponding amount. Converting this pressure to mass units, we find that the mass corresponding to a 1-meter-square column of air is 20.9 kilograms. If we assume that the antenna is affecting a 100-meter-by-100-meter area, the total mass of air affected is 10,000 square meters. This gives us a total of about 209,000 kilograms of total air, or about 209

tons of air. The CO₂ concentration in the atmosphere is currently about 360 ppm, which gives a total mass of CO₂ in the column of 76 kG or 0.076 tons (the amount of CO₂ would likely be less, given the higher molecular weight of CO₂, which would tend to pull it toward the earth, and away from the upper atmosphere). If we assume that every CO₂ molecule in this control volume is ejected into space during the course of 1 hour, the electrical generators providing the power are producing and releasing 46 times more CO₂ into the atmosphere than are being ejected during this time.

Another issue seems to be that ionizing the CO₂ does not guarantee that it will remain ionized forever—it will collide with other molecules on its way into space, and could likely steal an electron from a molecule with which it interacts. When the CO₂ loses its ionic charge, it also loses its tendency to drift into space, which means it needs to be re-energized before it drifts further up. In addition, the upper atmosphere is called the ionosphere because of the significant amount of ionization that occurs from solar radiation, which means that there will be free electrons in abundance (Ionosphere, 2009). There is also a tendency for CO₂ to freeze when released in the ionosphere (Eccles et al., 1993). The mechanism described by Wong has resulted in some loss of atmospheric gases, but this loss, summed over the history of the earth, is estimated to be only 2% of the total oxygen in the atmosphere (Atmosphere, 2009).

There is the additional problem that ejected CO₂ ions are subjected to two forces in space. One force is the magnetic field lines associated with the earth's core (the reason why the aurora occurs in the north), which would simply direct the ions to the oppositely charged South Pole. The other force is the gravitational field of the earth, which would tend to pull the CO₂ molecules back into the atmosphere.

Wong's idea resulted in some discussion on the Internet, with most scientists somewhat skeptical of it (Wong, 2009). Based on these observations, it does not appear that atmospheric CO₂ would be reduced by this method.

Shallow Injection of CO₂

Shallow Carbon Sequestration Demonstration Project

The Shallow Carbon Sequestration Demonstration Project is a joint project between DOE and various public, private, and academic institutions, and the information given here is based on DOE's report on the project (DOE, 2009b). The goal of the project is to assess the feasibility of CO₂ sequestration on-site at several Missouri power plants. The DOE provided \$2.36 million in funding for the \$2.95 million project. If preliminary phase findings are positive, CO₂ in the gas phase will be injected into the Lamotte and Reagan Formations to see how the gas reacts with groundwater and the surrounding rock. In addition, hydrodynamics, solubility, and mineral trapping will be tested. Eighty percent of Missouri's electricity is coal-fired. However, there are few geologic basins within Missouri

that are suitable for sequestration; therefore, the state is interested in testing on-site shallow carbon sequestration at its power plants.

The Lamotte and Reagan Formations appear to be adequate for sequestration, each displaying a porous layer capped by an impermeable layer; but these formations are not deep enough for CO₂ to remain in a supercritical state. Therefore, the CO₂ will be injected and stored in its gaseous phase. If the project is successful, it will give Missouri electric utilities a carbon mitigation option other than building a pipeline network to transport CO₂ to other states for sequestration.

Sequestration of CO₂ in Mixtures of Bauxite Residue and Saline Wastewater

Waste produced during the mining of bauxite is caustic with a pH of 13, according to Dilmore et al. (2008), whose article provided the information for this section. It is proposed that combining bauxite residue slurry, brine water from oil field production, and CO₂ will neutralize the caustic slurry and sequester CO₂. At 20°C and 0.689 megapascal (MPa), a bauxite residue/brine mixture of 90/10 was able to sequester 9.5 g/L (grams per liter) of CO₂ when exposed to pure CO₂. The domestic oil and gas industries generate between 20 and 30 billion barrels of saline-produced water annually. Most of this water is re-injected, but about 35% of it is treated and released to surface water bodies. The water-treatment process is costly. Positively charged calcium, magnesium, and iron ions in brine water can react with CO₂ to form stable calcium carbonate, magnesium carbonate, and iron carbonate minerals when under the proper temperature, pressure, and pH conditions. These minerals will permanently sequester CO₂ once they are formed, but many types of brines have a pH too low for carbonation to take place. Over 70 million dry metric tons of bauxite residue are produced annually as a by-product of aluminum mining. Bauxite residue slurry has a high pH. Adding brine to the bauxite residue reduces the pH, but the solution is only neutralized with the addition of CO₂. This method has the potential to sequester 1.3 million metric tons of CO₂ per year, less than half the CO₂ emitted annually from a 550 MW coal-fired power plant. Thus, this method would not be a large-scale carbon sequestration option. The main purpose of the process is to neutralize environmentally hazardous caustic bauxite residue slurry.

Mineral Carbonation of CO₂ in Fly Ash

A study conducted in Poland to assess the carbon sequestration ability of ash-aqueous suspensions derived from fly ash produced during the combustion of lignite coal is reported in Uliasz-Bochenczyk et al. (2009), whose information is used here to describe this method. Currently 5 power plants and 2 heat and power plants in Poland use lignite as their primary fuel source. Together these plants produce about 55,000,000 tons of CO₂ and 5,500,000 tons of fly ash. Outside of mining operations, fly ash has limited economic use. For the study, ash-aqueous suspensions were prepared using fly ash from the 3 largest lignite-burning power plants in Poland: Selchatow, Patnow, and Turow. Compared to fly

ash from the combustion of harder coals, fly ash from lignite is characterized by high CaO (calcium oxide) and free CaO content. For the experiment, CO₂ was introduced into a chamber filled to 30–35% of its capacity with fly ash suspension. The chambers were outfitted with instruments to measure temperature and pressure converters. Some of the samples were shaken and the pressure of CO₂ increased. The samples were shaken until the pressure dropped, which signified that the CO₂ had been absorbed into the suspension. The process was repeated until the suspension could absorb no more CO₂ and the pressure stabilized. After the shaking subsided, the samples were left for seasoning, while their temperature and pressures were continually monitored. The average amount of CO₂ absorbed into the suspensions during the research was 5.5 grams of CO₂ per 100 grams of ash. Each year 2,400,000 tons of fly ash is not used for economic purposes. If this fly ash was used for sequestration, 1,300,000 tons of CO₂ could be sequestered.

Conclusions

In order for the U.S. Air Force to purchase synthetic fuel from a CTL plant in Fairbanks, it must meet the requirement given in Section 526 of the Energy Independence and Security Act of 2007, that life-cycle greenhouse gas emissions of new fuel be less than or equal to that of the conventional fuel it replaces. The proposed plant design includes CO₂ separation, but estimates given in the Hatch Report do not include the cost of transporting or storing the CO₂. A literature review has been conducted to assess the current state of the art with respect to CO₂ storage. The following observations have been made:

- Enhanced oil recovery using CO₂, used in the oil industry for decades, provides economic value for the CO₂, increases production from aging oil fields, and provides a secure geologic formation for long-term storage. Since no oil or gas fields are located in the Fairbanks area, using CO₂ from the proposed CTL plant for EOR will require construction of a pipeline several hundred miles long, adding to the capital cost of the plant. Other sources of CO₂ may be available to these oil fields.
- There are no depleted oil or gas fields in the Fairbanks area that might be used to store CO₂.
- There are no deep wells in the Fairbanks area that indicate the presence of deep saline aquifers, and the integrity of the cap rock structure is unknown.
- Deep unmineable coal seams might be used for CO₂ sequestration, but the nearest known location of coal seams is in the Healy area, about 130 miles from the proposed CTL plant.

- Storage of CO₂ under permafrost requires deep continuous permafrost, which does not exist in the Fairbanks area.
- Storage of CO₂ in methane hydrate formations on the North Slope may be possible, but this is still in the research stage, and it is not yet known if this is a practical method for storing large amounts of CO₂.
- Chemical reactions of CO₂ with mafic rock can store CO₂ in solid form, but reaction rates are much too slow for this to be a practical method for CO₂ sequestration, and attempts to accelerate these reactions are still in the research stage.
- Other proposals to remove CO₂ from the atmosphere, including deep ocean storage, shallow CO₂ injection, and ejecting CO₂ molecules from the upper atmosphere do not appear practical.

In summary, all of the CO₂ storage options identified have significant economic costs (such as building a long pipeline for EOR) or significant technical risk.

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CHAPTER 4

Literature Review of Carbon Sequestration Costs and a Model of Capture and Sequestration Costs

by Virginia Fay

Summary

The following list summarizes findings from an extensive review of the literature on the cost of CO₂ capture and sequestration, and application of the studies to an Interior Alaska coal-to-liquids (CTL) facility (Appendix 4.B):

- There is significant uncertainty on the likely cost of carbon capture and sequestration.
- Much of this uncertainty results from few constructed and operational facilities using the potential capture, transport, and sequestration technologies applicable to the Interior Alaska CTL facility under consideration for this project.
- A significant number of demonstration projects are being developed between 2008 and 2015. These projects will increase the state of knowledge on capture and sequestration technologies and their costs.
- The majority of economic cost analyses and demonstration projects are directed at coal-fired facilities that generate electricity, because these are the most significant stationary sources of CO₂ emissions. Generally, the CO₂ emissions at these facilities are of higher temperature and lower concentration, with higher costs of capture.
- Oil and gas development fields use CO₂ stripped from natural gas for enhanced oil recovery (EOR) through re-injection of CO₂. An extensive system of stainless steel pipelines is used primarily in the midwestern United States to transport CO₂ to oil fields. While this use and technology is well established, the distances from the proposed CTL facility to oil and gas fields in Alaska appear to make this use cost-prohibitive.
- The emission characteristics of the Interior Alaska CTL facility include streams that both are concentrated and easy to capture and are less concentrated and more difficult to capture. The cost of capture of these streams was matched with the most applicable cost-of-capture estimates from the literature on economics.

- Estimates of costs per ton of CO₂ captured and sequestered are based on the type of facility, the timing of construction, and the assumption that costs will decline over time as more facilities are constructed with capture technologies.
- Few of the cost-per-ton analyses are directly applicable to the Interior Alaska CTL facility and the cases described in the Hatch Report. To address this issue, information from the Hatch Report including cases and plant characteristics are supplemented with additional data from Alaska studies on CO₂ compression, injection wells, and pipeline construction costs.
- Two separate modeling approaches are used. One method is a cost-per-ton analysis using costs from the economic literature. The other method is based on the specific capital and operating costs of capture, transportation, and sequestration added to the Hatch facility.
- For both of these modeling approaches, numerous scenarios are modeled including the three cases described in the Hatch Report, a facility located at Eielson Air Force Base and one at the mine mouth at Usibelli, CO₂ sequestered in coal seams and at the North Slope oil fields, and full and partial capture.
- All of the modeling results are presented in terms of potential additional cost per gallon of product that the CO₂ capture-and-sequestration process contributes.
- The modeling analysis is hampered by gaps in the description of operational processes of the facility in the Hatch Report relevant to CO₂ capture and sequestration. In particular, the operations and management costs of equipment to capture CO₂ may be underestimated and, thus, these costs may be low.
- A summary of model results for a variety of potential scenarios are contained in Table 4.5 and presented in more detail in Appendix 4.A.

Overview of Cost Studies and Issues

An extensive review of the literature on the cost of CO₂ capture and sequestration was conducted. This review focused primarily on the cost of capture and sequestration of CO₂ from large stationary sources. One paper in particular provided a succinct overview of the literature on the costs of CO₂ capture and sequestration, and identified some of the major issues and obstacles to deriving cost estimates (Richards, 2007). The author's review as well as this review of pertinent literature concerning CO₂ capture and sequestration costs found two prominent issues. These issues include

- lack of comparability of results of economic studies on carbon sequestration in terms of dollars per ton of carbon sequestered, and

- difficulty of implementing a market-based large-scale carbon sequestration program, which results in lack of policy and program parameters on which to base cost analyses and estimates. Without a carbon policy and program in place, it is difficult to model program and project costs.

Results of cost studies vary widely depending on the assumptions regarding program specifics and types of models used. The three basic types of models in use for estimating carbon sequestration costs are bottom-up or engineering models, sectoral models, and econometric models. Each type has different strengths and weaknesses. The bottom-up models tend to be simple and transparent, but generally include no concessions for friction in the market or interactions between sectors. For example, as more CO₂ is captured and its supply increases, the dollar amount that oil and gas developers are willing to pay for its use for EOR is likely to decline. This tendency further complicates the value of captured CO₂ for EOR depending on the fluctuating price of oil. Engineering models generally lack the feedback mechanisms inherent in complex markets.

The sectoral and econometric models provide more insight into the dynamics of market interactions. The sectoral models are less data-intensive than the econometric models and are based on existing supply and demand equations, while econometric models attempt to capture changes in supply and demand resulting from carbon sequestration programs and policies. In general, econometric studies tend to provide higher estimates of carbon sequestration costs, while bottom-up models provide lower estimates because they account for less of the overall counteracting results (Richards, 2007).

The lack of a carbon policy and program hampers this analysis because there is no basis for estimating the cost of CO₂ not captured and emitted. The three cases analyzed in the Hatch Report have different CO₂ production, capture, and emissions rates (Drover, 2008). There is no cost placed on emitted CO₂ in this analysis.

Types of Costs

Another reason for the large range in cost estimates is that studies provide estimates of different types of costs. Some studies provide only point estimates of costs, corresponding to specific carbon sequestration targets. Other studies provide cost curves that correspond to a range of carbon sequestration levels, generally demonstrating the expected upward-sloping curves. Among those studies that provide cost curves, however, there is significant variation because they may be estimating one of three different types of costs—total cost, average cost, or marginal cost—expressed as a function of annual, cumulative, or present equivalent sequestration levels. This variation produces nine possible types of cost curves, none of which can be directly compared to the others (Richards, 2007). There seems to be an emerging consensus that curves expressing marginal costs as a function of equivalent annualized sequestration levels are the most

useful for comparing across analyses of mitigation options, but there is still no universally accepted format. Many studies do not clearly identify the type of costs reported.

Definition of “Dollars per Ton”

Another problem when comparing study results is that there is not a common definition of “dollars per ton.” Most studies use either a present or an annualized value of costs (numerator), and studies employ different definitions for “ton” (denominator), which results in different definitions of dollars per ton. One method used for calculating cost per ton is a “flow summation” approach, which defines tons in the denominator as the total flow of carbon throughout the life of the project or program (Richards, 2007). Again, with the lack of a carbon-pricing program or policy and with an escalating price for CO₂ over time, accurately valuing and discounting CO₂ emissions over the life of a project is hampered.

A number of studies estimate the potential cost per ton of CO₂ captured for specific projects or types of projects. Coal-fired facilities that generate electricity contribute a significant portion of stationary CO₂ emissions in the United States. As a result, the majority of estimates of per-ton cost are for potential projects related to future electrical generation. Few capture-and-sequestration projects have been completed to date to test these cost estimates. In 2008, 2 demonstration projects were started; another 4 are scheduled to begin in 2009, and 26 more are planned for 2010 to 2015 (Table 4.1, Figure 4.1).

Table 4.1. Planned CO₂ capture and storage demonstration projects by type and location, 2008–2015 (from MIT CCS project database, 2009).

Project Name	Location	Leader	Feedstock	Size MW	Capture Process	CO ₂ Fate	Start-up
Schwarze Pumpe	Germany	Vattenfall	Coal	30/300/1000*	Oxy	Seq / EOR	2008
Pleasant Prairie	USA	AEP	Coal	5	Post	Seq	2008
AEP Alstom Mountaineer	USA	AEP	Coal	30	Post	Seq	2009
Total Lacq	France	Total	Oil	35	Oxy	Seq	2009
Callide-A Oxy Fuel	Australia	CS Energy	Coal	30	Oxy	Seq	2009
GreenGen	China	GreenGen	Coal	250/800**	Pre	Seq	2009
Williston	USA	PCOR	Coal	450	Post	EOR	2009-15
Kimberlina	USA	CES	Coal	50	Oxy	Seq	2010
NZEC	China	UK&China	Coal	Undecided	Undecided	Seq	2010
AEP Alstom Northeastern	USA	AEP	Coal	200	Post	EOR	2011
Plant Barry	USA	MHI	Coal	25	Post	Seq	2011
Sargas Husnes	Norway	Sargas	Coal	400	Post	EOR	2011
Scottish & S. Energy Ferrybridge	UK	SSE	Coal	500	Post	Seq	2011-2012
Naturkraft Kårstø	Norway	Naturkraft	Gas	420	Post	Undecided	2011-2012
ZeroGen	Australia	ZeroGen	Coal	100	Pre	Seq	2012
Antelope Valley	USA	Basin Electric	Coal	120	Post	EOR	2012
WA Parish	USA	NRG Energy	Coal	125	Post	EOR	2012
Appalachian Power	USA	AEP	Coal	629	Pre	Undecided	2012
Teeside	UK	CE	Coal	800	Post	Seq	2012
Wallula Energy Resource Center	USA	Wallula Energy	Coal	600-700	Pre	Seq	2013
RWE npower Tilbury	UK	RWE	Coal	1600	Post	Seq	2013
Tenaska	USA	Tenaska	Coal	600	Post	EOR	2014
HECA	USA	HEI	Petcoke	390	Post	EOR	2014
UK CCS project	UK	TBD	Coal	300-400	Post	Seq	2014
Statoil Mongstad	Norway	Statoil	Gas	630 CHP	Post	Seq	2014
Bow City	Canada	BCPL	Coal	1000	Post	EOR	2014
Janschwalde	Germany	Vattenfall	Coal	500	Oxy & Post	EGR	2015
RWE Goldenbergwerk	Germany	RWE	Coal	450	Pre	Seq	2015
AMPGS	USA	AMP	Coal	1000	Post	EOR	2015
Boundary Dam	Canada	SaskPower	Coal	100	Oxy	EOR	2015
Meri Pori	Finland	Fortum	Coal	565	Post	Unknown	2015
Nuon Magnum	Netherlands	Nuon	Various	1200	Pre	Seq	2015
Powerfuel Hatfield	UK	Powerfuel	Coal	900	Pre	EOR	Undecided
ZENG Worham-Steed	USA	CO2-Global	Gas	70	Oxy	EOR	Undecided
Polygen Project	Canada	SaskPower	Coal/Petcoke	300	Pre	Undecided	Undecided
ZENG Risavika	Norway	CO2-Norway	Gas	50-70	Oxy	Undecided	Undecided
E.ON Karlshamn	Sweden	E.ON	Oil	5	Post	Undecided	Undecided
<i>Restructuring/ Dormant</i>							
FutureGen	USA	FutureGen Alliance	Coal	275	Pre	Seq	Structuring
BP Carson (DF2)	USA	Hydrogen Energy	Petcoke	500	Pre	EOR	Structuring
UAE Project	UAE	Masdar	Gas	420	Pre	EOR	Delayed
E.ON Killingholme	UK	E.ON	Coal	450	Pre	Seq	Dormant
Monash Energy	Australia	Monash	Coal	60 k bpd	Pre	Seq	Dormant
<i>Cancelled</i>							
BP Rio Tinto Kwinana (DF3)	Australia	BP	Coal	500	Pre	Seq	Cancelled
BP Peterhead (DF1)	UK	BP	Gas	475	Pre	EOR	Cancelled
SaskPower Clean Coal	Canada	SaskPower	Coal	450	Oxy	Unknown	Cancelled
Halten CO ₂ Project (Draugen)	Norway	Shell & Statoil	Gas	860	Post	Unknown	Cancelled
For fact sheets see:							
http://sequestration.mit.edu/tools/projects/index.htm							
Abbreviations used:							
EOR = Enhanced Oil Recovery							
EGR = Enhanced Gas Recovery							
Gas Process = Gas Processing							
Coal Gas = Coal Gassification							
LNG Process = Liquid Natural Gas Processing							
Natural Dep = Natural Deposit							
H ₂ Prod = Hydrogen Gas Production							
Brine Res = Brine Reservoir							
Depleted Gas Res = Depleted Gas Reservoir							
Depleted Oil Res = Depleted Oil Reservoir							
Sandstone Res = Sandstone Reservoir							
TBD = To Be Decided							



Figure 4.1. CO₂ capture and storage projects by type and location, 2008–2015 (from MIT CCS project database, 2009).

Table 4.2 contains estimates of average cost per ton of CO₂ captured and sequestered. Compiled from a number of studies, these cost estimates are summarized for early demonstration, early and full-scale commercial projects, as well as chemical processes, EOR, and pipeline transportation costs. The estimates include an assumption that CO₂ is transported less than 100 kilometers to a sequestration site. Until these early demonstration projects are constructed, operated, and evaluated, the costs are estimates.

Table 4.2. Summary of estimated potential costs from studies on CO₂ capture and sequestration (from McKinsey and Company, 2008, and Anderson and Newell, 2004).

Studies	US dollars per ton of CO₂	
	Range	
	Low	High
McKinsey, 2008		
Early demonstration projects	85	125
Early full scale commercial	50	70
Full scale commercial in 2030	40	65
Transportation distance > 200 km add:	10	10
Off shore sequestration add:	19	17
Anderson & Newell, 2004		
Coal electric facilities*	200	250
Coal electric w/ near term technical improvements**	160	190
Industrial facilities such as NG	50	90
Statoil, Norway	55	
Petroleum refining (Dutch residual gasification)	90	
Chemical (Dutch petrochemicals)	245	
Hydrogen production	50	75
Transportation per 100 km	5	10
Storage		
Enhanced oil recovery net benefits***	-15	-30
Aquifers	5	45
Enhanced coal-bed methane	-20	
*Including \$37/ton CO ₂ stored for transportation and storage costs.		
**Lower costs due to near-term improvements from demonstration projects and carbon policies raising the cost of emissions.		
***For limited amounts in CO ₂ low circumstances; expected to go to zero with increased availability of CO ₂ ; zero in NG field due to co-existence w/ NG.		

Model of CO₂ Capture and Sequestration Costs for a Coal-to-Liquids Facility in Interior Alaska

Methods

This analysis uses two different modeling approaches to address the uncertainty of cost estimates for CO₂ capture and sequestration. One method, which uses estimates of the average cost per ton of CO₂ captured and sequestered from studies in the literature review (Table 4.2), is referred to as the *cost per ton* analysis. The second method uses estimates of the additional capital costs of equipment required to capture, transport, and store CO₂ from the CTL plant under consideration. This method is referred to as the *capital cost* analysis. For the capital cost model, costs from the CO₂ capture and sequestration analysis for the 2006 *Beluga Coal Gasification Feasibility Study* (Chaney and Van Bibber, 2006) were adjusted for this CTL project. For both modeling approaches,

pipeline costs were developed based on the U.S. Department of Energy's *Alaska Spur Pipeline* study (U.S. Department of Energy, 2007).

Both modeling methods estimate the incremental cost that the CO₂ capture and sequestration process would add to a gallon of CTL output from the proposed facility as well as total annual costs of capture and sequestration based on the Hatch Report facility study. To address the uncertainty of cost estimates per ton and capital costs of capture equipment and pipelines, sensitivity analyses were conducted to estimate the potential range of costs. The analyses include the three cases outlined in the Hatch Report as well as different plant locations and CO₂ sequestration sites.

Relatively few CO₂ capture studies focus specifically on industrial processes such as CTL. Therefore, for this analysis costs-per-ton estimates were selected that most closely match the CTL facility under consideration. The industrial process for CTL results in a relatively concentrated, cool, "easy to capture" emission stream of CO₂ and an emission stream that is more difficult to capture.

Three different facility cases were presented in the Hatch Report, each producing different amounts of CO₂ and product outputs (Table 4.3). Each of the three cases varies in terms of quantities of CO₂ produced, captured, and emitted. Other components of the scenarios modeled are facility locations at Eielson Air Force Base and the Usibelli mine mouth. Sequestration locations are Usibelli coal seams and North Slope oil fields.

Table 4.3. Anticipated CO₂ and product output from an Interior Alaska CTL facility (from Dровер, 2008).

		Hatch Report		
CO2	Units	Case 1	Case 2	Case 3
CO2 Produced	tons/year	5,873,545	11,747,090	5,852,591
CO2 Captured	tons/year	4,821,819	9,644,445	2,241,264
CO2 Emitted	tons/year	1,051,726	2,103,451	3,612,133
Product Output				
Jet-A	gal/year	121,333,271	242,497,298	242,567,816
Diesel	gal/year	88,246,225	176,365,518	176,407,829
Naphtha	gal/year	72,788,680	145,478,634	145,520,945
Total	gal/year	282,368,176	564,341,450	564,496,590

A summary of costs and assumptions are shown in Table 4.4. For the cost per ton analysis, the easy-to-capture CO₂ stream was assumed to have a full-scale commercial operation cost per ton, while the hard-to-capture stream was assumed to have the lower, early demonstration cost per ton. Pipeline costs were adjusted in the per-ton analysis to account for the 100-kilometer (60-mile) pipeline allowance included in this method. In

addition, it was assumed that operating costs were included in the per-ton cost estimates. Pipeline construction costs were estimated at \$2.78 million per mile.

The capital cost analysis is based on the additional capital costs of equipment for CO₂ capture and sequestration, which include CO₂ compressors, injection wells, and pipelines. The only operational costs assumed are the electrical energy use identified in the Hatch Report for CO₂ compression. However, this operational cost estimate may be an underestimate of actual costs and will be further investigated in Phase II of this study.

For both methods of analysis, the assumed project life is 25 years, the interest rate is 5%, the value of CO₂ for EOR is \$5 per ton, and electric power sales are valued at the Golden Valley Electric Association (GVEA) avoid-cost per kWh of \$0.20. The value of CO₂ for EOR is an estimate based on the Beluga coal gasification analysis and oil price forecasts. North Slope oil producers have not confirmed this value or that CO₂ would be purchased. More research on the value of CO₂ for North Slope EOR will be conducted in Phase II of this study.

Table 4.4. Cost assumptions for coal-to-liquids sensitivity analysis (from Anderson and Newell, 2004; Chaney and Van Bibber, 2006; U.S. Department of Energy, 2007; Drover, 2008; McKinsey and Company, 2008).

Per Ton Analysis		
Demonstration high	\$ per ton	\$125
Demonstration low	\$ per ton	\$85
Early commercial	\$ per ton	\$70
Full commercial 2030	\$ per ton	\$65
Pipeline/mile (millions US \$)	m\$ per project	\$2.78
Eielson to North Slope	m\$ per project	\$1,390
Eielson to Usibelli	m\$ per project	\$375
Usibelli to North Slope	m\$ per project	\$1,765
Usibelli to Usibelli	m\$ per project	\$56
Base Allowance (per ton only)	miles	60
Capital Costs Analysis		
CO ₂ compressor (millions US \$)	m\$ per project	\$69
injection wells (millions US \$)	m\$ per project	\$50
Total	m\$ per project	\$119
Pipeline/mile (millions US \$)	m\$ per project	\$2.78
Eielson to North Slope	m\$ per project	\$1,223
Eielson to Usibelli	m\$ per project	\$209
Usibelli to North Slope	m\$ per project	\$1,599
Usibelli to Usibelli	m\$ per project	-\$111
Operating Costs		
Decrease power production MWe	MWe	26
Variables		
Lifetime	years	25
Interest rate	annual	5%
Value EOR NS	per ton	\$5
Avoided GVEA energy	kWh	\$0.20
Distances		
Eielson to North Slope	miles	500
Eielson to Usibelli	miles	135
Usibelli to North Slope	miles	635
Usibelli to Usibelli	miles	20

Results

A summary of preliminary results of this analysis are shown in Table 4.5; detailed results are contained in Appendix 4.A. A number of scenarios were modeled for the three cases presented in the Hatch Report. For each scenario, an analysis based on capital cost

and per-ton cost was conducted. Results are presented as dollars per ton of CO₂ sequestered, total dollars per year, and average dollars per gallon of output product produced. Also tested are differing full- and partial-capture scenarios. These reflect differences in costs for emissions that are easy to capture and hard to capture, and assumptions on ultimate capture rates.

The CTL facility locations tested were Eielson Air Force Base and Usibelli mine mouth. Sequestration sites tested for both facility locations were Usibelli coal seams and North Slope oil fields. No allowances were made for CO₂ not captured and emitted; no assumptions were made regarding CO₂ taxes per tons of CO₂ emitted. These assumptions and others will be tested in Phase II of this study.

In general, the capital cost method produced lower costs per ton and per gallon of output produced than the cost per ton analysis. However, the capital cost analysis results are most likely too low because operating cost assumptions are insufficient. A more complete analysis of operating costs will be conducted in Phase II of this study.

Costs per ton of CO₂ sequestered ranged from \$9.47 for easy-to-capture CO₂ streams analyzed under the capital cost method for Hatch facility Case 2, to \$99.07 per ton for the hard-to-capture CO₂ stream for the Hatch facility Case 1, both located at Eielson Air Force Base and sequestered at Usibelli. On a per-gallon incremental-cost basis, costs ranged from \$0.09 per gallon for easy-to-capture CO₂ under Case 3 to \$1.81 per gallon for Case 1 CO₂ pipelined from Usibelli to the North Slope. On a total annual cost basis, costs ranged from approximately \$48 million per year for easy-to-capture Case 3 CO₂ sequestered at Usibelli, to \$909 million per year for Case 2 full-capture CO₂ sequestered on the North Slope.

The variations in costs are attributable to economies of scale between Case 1, with a smaller amount of output than Cases 2 and 3. In addition, Case 3 tends to have generally lower costs because a greater portion of CO₂ is emitted. Assumptions of a carbon tax or the requirement to fully capture CO₂ emissions would change these results. Figure 4.2 compares modeling methods, cases, and capture streams for a facility located at Eielson Air Force Base with CO₂ sequestered in Usibelli Coal Mine seams. Figure 4.3 shows full capture for Cases 1 through 3, but varies plant and sequestration locations.

Table 4.5. Preliminary results of sensitivity analysis of costs of CO₂ capture and sequestration at an Interior Alaska coal-to-liquids facility (prepared by V. Fay and N. Szymoniak).

Plant/Pipeline Path	Streams	Hatch Report		
	All Captured	Case 1	Case 2	Case 3
Eielson to Usibelli				
Captial based	\$/ton	\$19.59	\$16.59	\$40.71
	\$/year	\$115,051,300	\$194,869,617	\$238,252,291
	\$/gal product	\$0.41	\$0.35	\$0.42
Per ton	\$/ton	\$75.20	\$73.95	\$81.80
	\$/year	\$441,717,619	\$868,698,064	\$478,713,376
	\$/gal product	\$1.56	\$1.54	\$0.85
Eielson to Usibelli	Easy to Capture	Case 1	Case 2	Case 3
Captial based	\$/ton	\$13.11	\$9.47	\$21.48
	\$/year	\$63,210,160	\$91,353,223	\$48,150,987
	\$/gal product	\$0.22	\$0.16	\$0.09
Per ton	\$/ton	\$73.07	\$71.53	\$76.60
	\$/year	\$352,320,943	\$689,904,712	\$171,682,034
	\$/gal product	\$1.25	\$1.22	\$0.30
Eielson to Usibelli	Hard to Capture	Case 1	Case 2	Case 3
Captial based	\$/ton	\$82.64	\$65.89	\$62.34
	\$/year	\$86,912,940	\$138,592,224	\$225,177,133
	\$/gal product	\$0.31	\$0.25	\$0.40
Per ton	\$/ton	\$99.07	\$92.03	\$89.10
	\$/year	\$104,190,263	\$193,586,939	\$321,824,930
	\$/gal product	\$0.37	\$0.34	\$0.57
Usibelli to Usibelli	All Captured	Case 1	Case 2	Case 3
Captial based	\$/ton	\$15.73	\$14.66	\$36.83
	\$/year	\$92,367,800	\$172,186,117	\$215,568,790
	\$/gal product	\$0.33	\$0.31	\$0.38
Per ton	\$/ton	\$71.34	\$72.02	\$77.92
	\$/year	\$419,034,118	\$846,014,564	\$456,029,876
	\$/gal product	\$1.48	\$1.50	\$0.81
Usibelli to North Slope	All Captured	Case 1	Case 2	Case 3
Captial based	\$/ton	\$31.38	\$19.98	\$52.56
	\$/year	\$184,307,491	\$234,758,083	\$307,613,251
	\$/gal product	\$0.65	\$0.42	\$0.54
Per ton	\$/ton	\$87.00	\$77.35	\$93.65
	\$/year	\$510,973,809	\$908,586,530	\$548,074,337
	\$/gal product	\$1.81	\$1.61	\$0.97
Eielson to North Slope	All Captured	Case 1	Case 2	Case 3
Captial based	\$/ton	\$26.85	\$17.72	\$48.01
	\$/year	\$157,679,034	\$208,129,626	\$280,984,794
	\$/gal product	\$0.56	\$0.37	\$0.50
Per ton	\$/ton	\$82.46	\$75.08	\$89.10
	\$/year	\$484,345,352	\$881,958,073	\$521,445,879
	\$/gal product	\$1.72	\$1.56	\$0.92

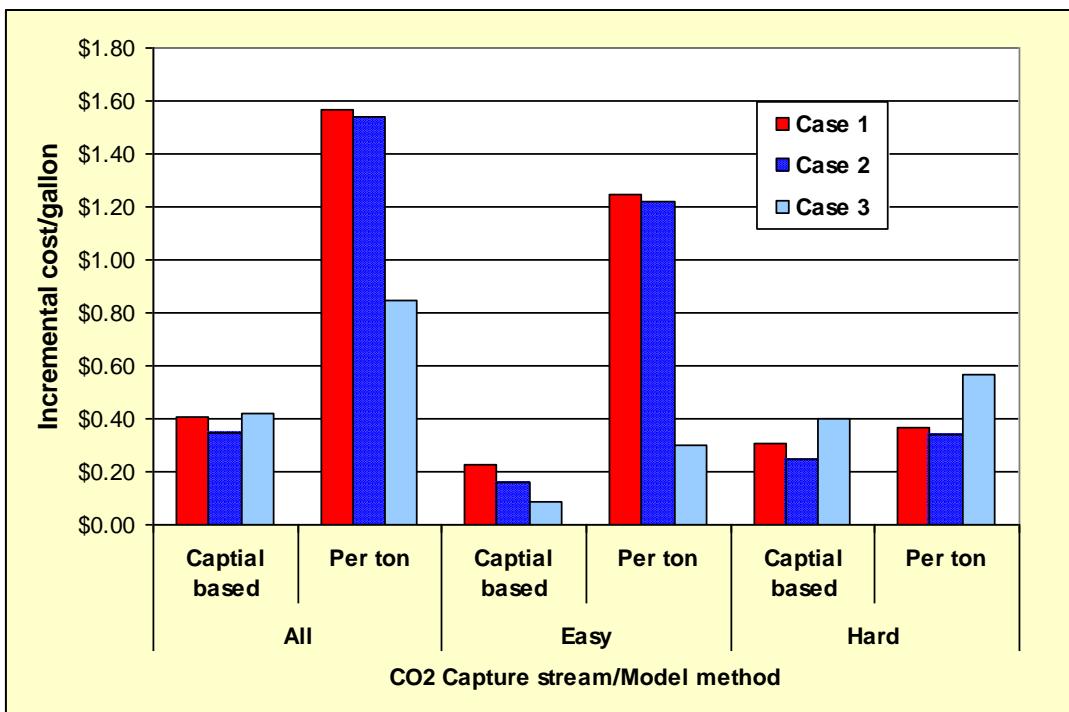


Figure 4.2. Comparison of results for carbon capture modeling methods, Hatch Report cases, and full and partial capture of easy- and hard-to-capture CO₂ emission streams, plant location Eielson AFB, sequestration Usibelli coal mine seams (prepared by V. Fay and N. Szymoniak).

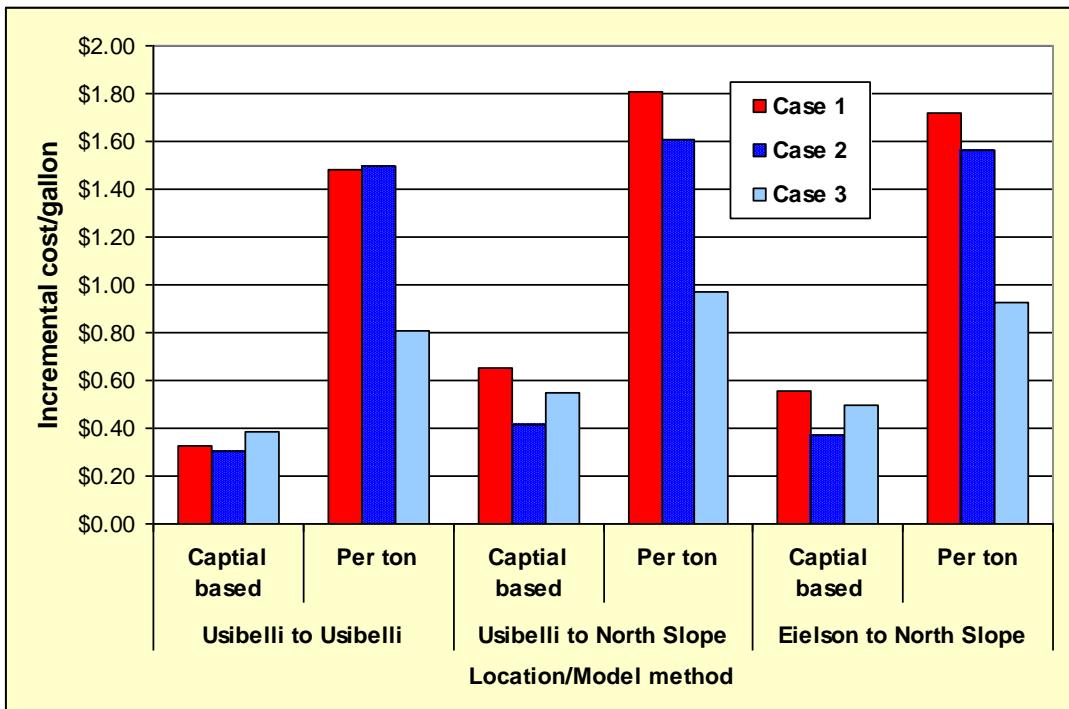


Figure 4.3. Comparison of results for carbon capture modeling methods, Hatch Report cases, and full CO₂ emission streams, with varying plant and sequestration locations (prepared by V. Fay and N. Szymoniak).

Review of Literature Pertinent to Interior Alaska Coal-to-Liquids Facility Carbon Sequestration

Given the likelihood that humans will remain dependent on fossil fuels as a primary source of energy during a transition period to renewable and other energy sources, and the growing consensus on the seriousness of global climate change, a considerable amount of research is being conducted on carbon capture and sequestration. A significant portion of this research is directed at forest and agricultural management practices to increase the rate of CO₂ sequestration. One of the tasks of the present study was to review biological sequestration options and costs. The economic cost modeling and literature review task focused primarily on industrial facility capture and sequestration. Relatively little time was spent conducting economic analyses on biological sequestration, because it is not likely to provide a viable solution for CO₂ sequestration for a CTL facility in Interior Alaska. For more details, see Chapter 2 of this report.

Another significant portion of research is being directed at CO₂ sequestration for coal-fired facilities that generate electricity. A relatively wide range of costs per ton of sequestered CO₂ is estimated from this research (Table 4.2), and this is attributable to differing conditions as well as rapid advances in the development of this technology.

Estimated capture and sequestration costs per ton vary depending on types of facilities and assumptions on distances and storage costs. In addition, the relative concentration of CO₂ in emissions changes the costs of capture—the higher the concentration, the lower the cost. As a result, industrial processes such as refineries and this Interior Alaska CTL facility have higher concentration streams of CO₂ emissions. Emissions that are higher in concentration and lower in temperature generally have lower capture costs. The lowest of these industrial processes is natural gas production, in which the CO₂ is stripped from the gas before transport and re-injected for EOR and storage in depleted gas wells. A list of the articles reviewed for this analysis is contained in Appendix 4.B.

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CHAPTER 5

Assessment of Other Pollutants and Wastes Associated with the Gasification of Alaskan Low-Rank Subbituminous Coal

by Rajive Ganguli

Abstract

Alaska has vast reserves of environmentally friendly coal (in terms of sulfur and trace elements) to support a coal-to-liquids (CTL) plant in any one of its three major coal regions, including Fairbanks. Recent studies that have specifically looked into coal gasification in Beluga (Chaney and Bibber, 2006), Fairbanks (Dover, 2008), and Healy (Bibber et al., 2007) support that notion. There are a variety of competing options for specific gasification technologies including gasifier type (fixed bed, circulating bed, and entrained flow), gasification temperature (dry ash or slagging), and feed type (slurry or non-slurry fed), though recent studies have only focused on slagging entrained-flow gasifiers. The major pollutants from gasification are expected to be solids (ash), liquids (mostly process water), and gases (CO, CO₂, NO_x, SO_x, particulate matter, and water vapor).

Gasification, especially with entrained-flow gasifiers, is expensive, since high temperatures combined with pollutants in coal severely affect gasification and downstream equipment. Ultra cleaning of coal (UCC), which is different from common coal beneficiation, can reduce ash content to less than 0.1%. This process has been explored in the United Kingdom and Australia in an attempt to directly combust coal in a gas turbine. Following success in the lab, a pilot plant is being built in Australia to apply UCC technology on a large scale to obtain ultra cleaned coal that can be directly fed into a gas turbine. Ultra cleaning of coal should be explored for its applicability and benefits for a CTL plant in Alaska.

Introduction

This chapter reviews the literature for information on the issues listed below with respect to coal gasification:

- Quality of Alaskan coal
- Gasification technologies
- Impact of pollutants and mitigation possibilities

The focus of this chapter strays slightly from the original proposal because of instructions received during the kickoff meeting (June 26, 2009), when the funding agency requested that the task review all Alaskan coal.

Review of Quality of Alaskan Coal

Coal resources in Alaska have been estimated (hypothetical) to be upwards of 5,000 billion tons (Flores et al., 2004), and account for almost 15% of the world's coal resource (Clough, 2008). To put this into perspective, consider that in 2008 the United States mined about 1.2 billion tons of coal (Freme, 2009). According to Schaff (1983), Alaskan coal is essentially either bituminous (57% of total) or subbituminous (42% of total). These coal types are good from an emissions perspective (Alaska DGGS, 1993), as they contain low amounts of sulfur, especially pyritic sulfur (the kind responsible for acid mine drainage), metallic trace elements, and nitrogen. The primary coal regions of Alaska (Figure 5.1) are Northern Alaska – Slope, Central Alaska – Nenana, and Southern Alaska – Cook Inlet. Unless otherwise mentioned, the information for this section is obtained from the U.S. Geological Survey (USGS) report by Flores et al. (2004).

Northern Alaska – Slope Region

The Northern Alaska – Slope is the largest coal region in the United States, containing 150 billion tons of identified coal resources. The Nanushuk Group, which constitutes a large portion of this region's coal, is estimated to have a resource upwards of 3,000 billion tons. The resource is primarily in the northern and northwest part of the North Slope and includes the National Petroleum Reserve – Alaska (NPRA). Coals in this group vary from lignite A to high-volatile bituminous and have received considerable attention in the past. Goff et al. (1986) provide a good overview of coal resources of this region, where currently, there is one active exploration program. Mining giant BHP Billiton is exploring bituminous coals 35 miles south of Point Lay (Figure 5.2) to confirm previous findings in the Deadfall Syncline area. Merritt (1985) reports that coal proven in the Deadfall Syncline area had Btu/lb (British thermal unit per pound) values of between 13,360 and 14,100. The coals on the northeastern side (around Prudhoe Bay) are part of the Sagavanirktok Formation and contain about 50 billion tons. Tables 5.1, 5.2, and 5.3 show the quality of coal from the Northern Alaska – Slope region.

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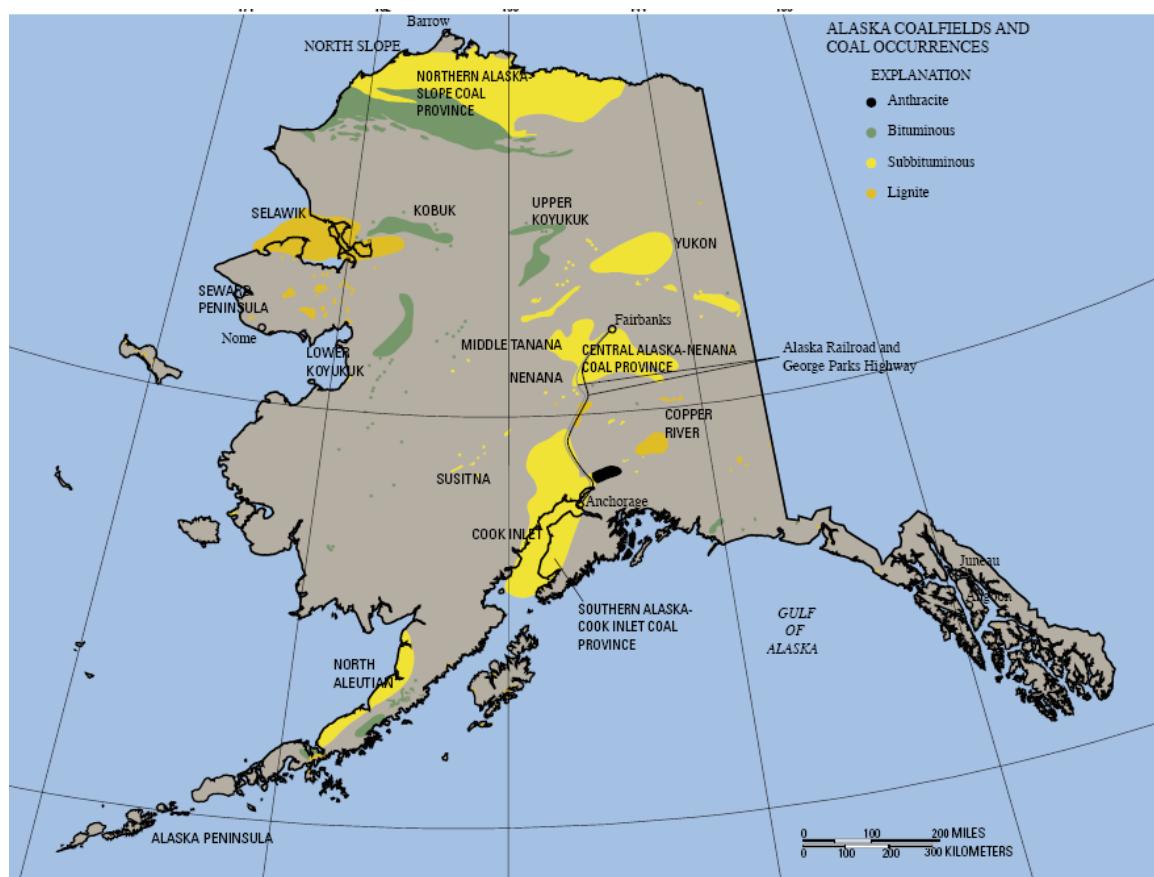


Figure 5.1. Distribution of coal in Alaska (Flores et al, 2004).

Assessment of CO₂ Sequestration Options and Other Environmental Impacts
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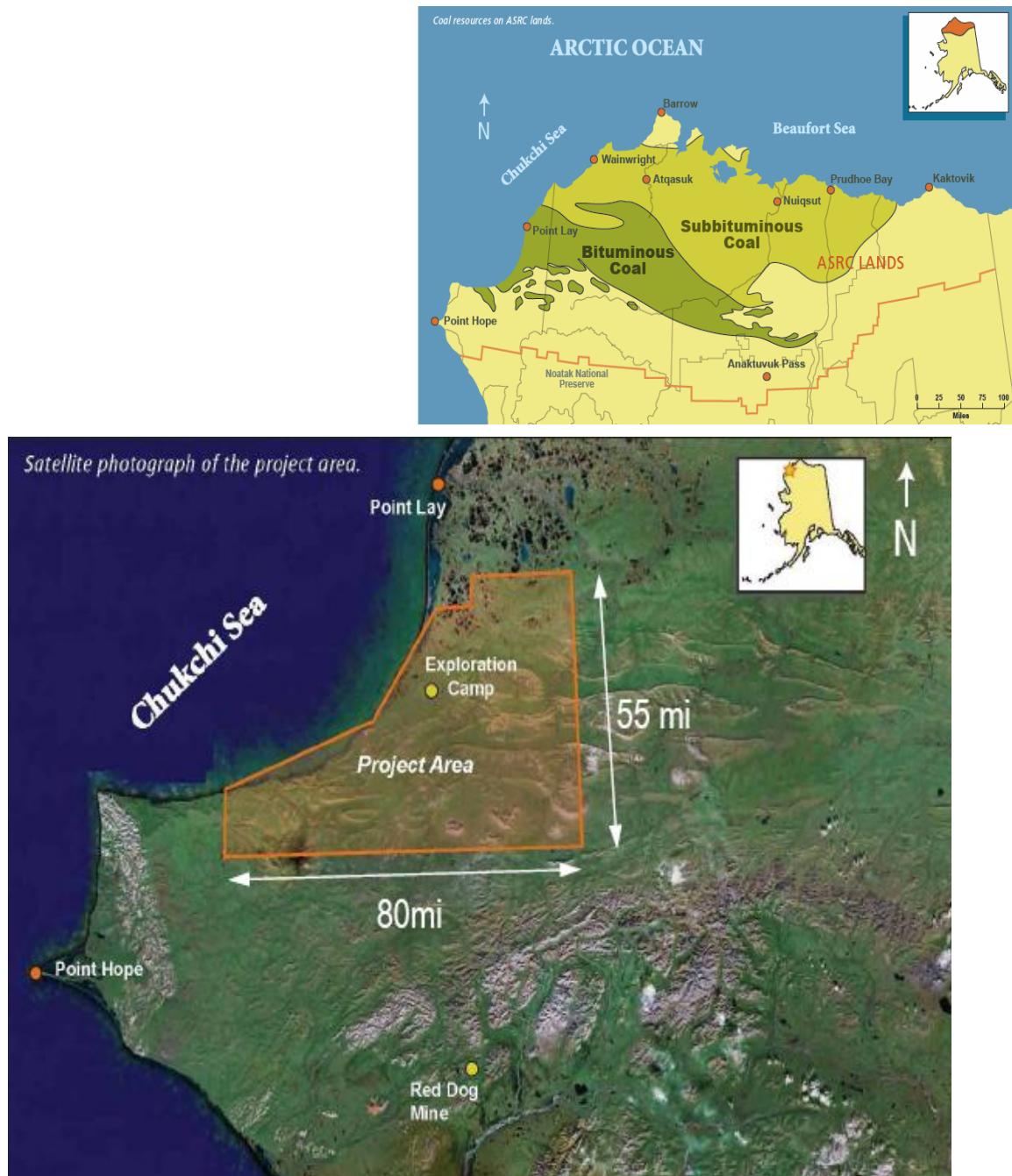


Figure 5.2. BHP Billiton coal exploration near Point Lay (images from bhpbilliton.com).

Table 5.1. Coal quality data (as received) from the Nanushuk Group in the Northern Alaska – Slope coal region (Flores et al., 2004).

Unit	Parameter	Number of samples	Range		Arithmetic mean	Standard deviation
			Minimum	Maximum		
Proximate and ultimate analysis						
	Moisture	68	1.80	33.10	12.52	7.12
	Volatile matter	68	22.10	40.00	30.07	3.82
	Fixed carbon	68	24.50	60.20	47.13	7.87
	Ash yield	68	2.30	37.20	10.28	7.82
	Hydrogen	52	3.82	6.25	5.24	0.48
	Carbon	52	43.92	72.50	60.96	8.54
	Nitrogen	52	0.72	1.85	1.29	0.30
	Oxygen	52	11.30	39.33	23.73	6.58
	Sulfur	73	0.10	2.00	0.31	0.23
Calorific value						
	Btu per pound	68	5,610	13,820	10,140	1,810
Forms-of-sulfur						
	Sulfate	37	0.01L	0.04	0.01	0.01
	Pyritic	37	0.01L	0.06	0.01	0.01
	Organic	37	0.01L	0.55	0.28	0.12
Ash-fusion-temperatures °F						
	Initial deformation	51	2,180	2,910G	5,540	200
	Softening temperature	51	2,130	2,910G	2,410	200
	Fluid temperature	51	2,030	2,910G	2,300	200

Note: "L" implies "less than" and "G" implies "greater than."

Author's note: Ash initial deformation temperature of 5,540 is probably an error in the reference.

Table 5.2. Coal quality data (as received) from the Tertiary Staines Tongue (Sagavanirktok Formation) in the Northern Alaska – Slope coal region (Flores et al., 2004).

Unit	Parameter	Number of samples	Range		Arithmetic mean	Standard deviation
			Minimum	Maximum		
Proximate and ultimate analysis						
	Moisture	68	18.44	35.97	27.04	3.85
	Volatile matter	68	23.78	36.09	30.16	2.73
	Fixed carbon	68	25.05	42.35	34.65	4.35
	Ash yield	68	1.16	25.46	8.15	6.24
	Hydrogen	68	5.11	7.12	6.19	0.42
	Carbon	68	35.07	55.11	46.22	4.94
	Nitrogen	62	0.59	1.70	1.04	0.22
	Oxygen	68	30.09	49.21	38.16	3.86
	Sulfur	160	0.06	1.65	0.31	0.33
Calorific value						
	Btu per pound	68	5,930	9,330	7,770	860
Forms-of-sulfur						
	Sulfate	160	0.01L	0.23	0.03	0.03
	Pyritic	160	0.01L	0.24	0.03	0.03
	Organic	160	0.01L	1.54	0.26	0.31
Ash-fusion-temperatures °F						
	Initial deformation	69	2,070	2,800G	2,460	240
	Softening temperature	69	1,930	2,800G	2,360	240
	Fluid temperature	69	1,890	2,800G	2,240	230

Table 5.3. Trace element content of Arctic coals (Clough et al., 2007).

Trace Element	Content (ppm)
Antimony	0.29
Arsenic	2.82
Beryllium	1.0
Cadmium	0.09
Chromium	16
Cobalt	8.2
Lead	5.5
Manganese	108
Mercury	0.05
Nickel	28
Selenium	0.67
Uranium	1.4

Central Alaska – Nenana Coal Region

The coals in the Central Alaska – Nenana coal region (Figure 5.3), which has an estimated identified resource of 8 billion tons, range from lignite to subbituminous. The only operating coal mine in Alaska, the Usibelli Coal Mine (UCM) located in Healy, is in this region. Healy is located 110 miles south of Fairbanks on the Parks Highway. The UCM mines subbituminous C rank coal (approximately 1.5 million tons per year) in the Nenana Coalfield, with a coal reserve of 700 million tons (Usibelli Coal Mine, 2009). The quality of the coal is given in Table 5.4. The Central Alaska – Nenana region also includes the Jarvis Creek Coalfield, which is located near Delta. The town of Delta, home to the U.S. Army's Fort Greely, is located 100 miles southeast of Fairbanks on the Richardson Highway. Jarvis Creek coal (with identified and hypothetical resources of 75 and 175 million tons, respectively) has a Btu/lb value of between 7,800 and 9,400, with ash ranging from 5.2% to 13.1%. Sulfur content, which is between 0.3% and 1.4%, is higher than UCM coals; moisture is between 20% and 23%. Around the Jarvis Creek mine, the coal quality is somewhat different: Btu/lb values are between 6,550 and 10,000, moisture is between 15.9% and 27.6%, ash is between 2.6% and 32.44%, and sulfur is between 0.3% and 1.83%. Merritt (1985) reports on mining in the area during the period 1950–1970.

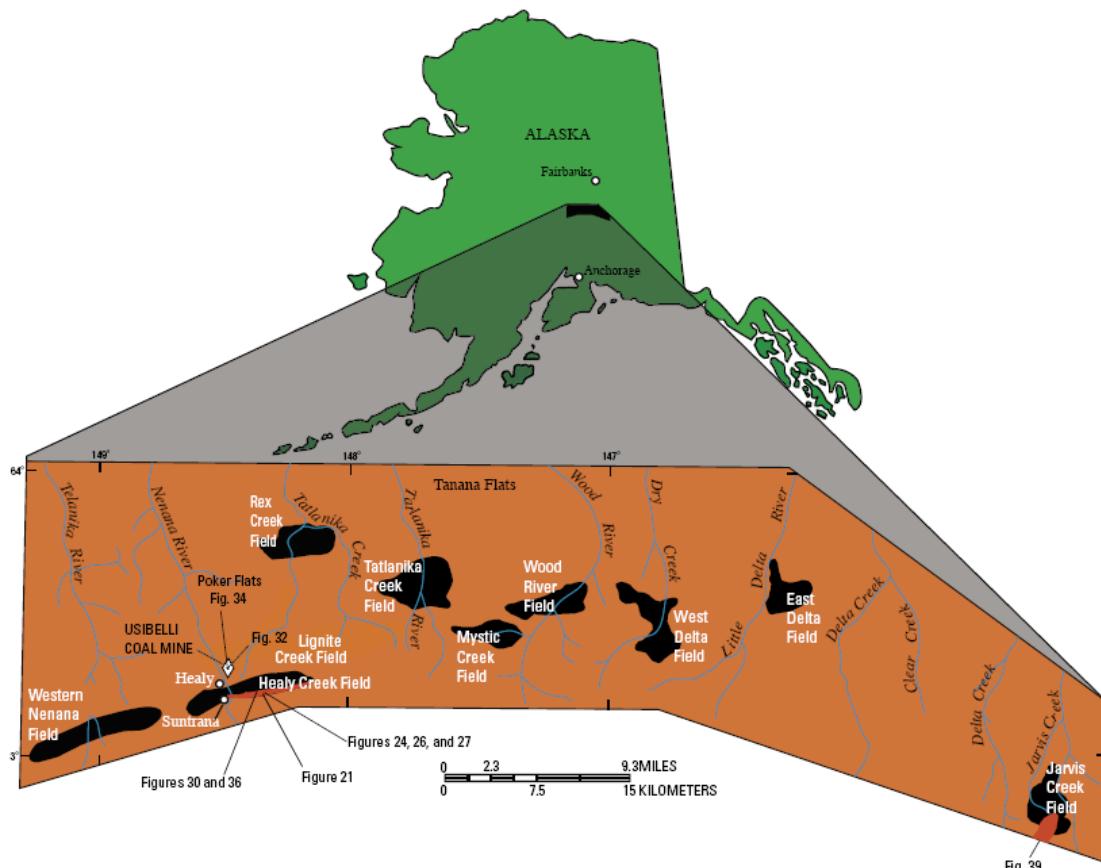


Figure 5.3. Central Alaska – Nenana coal region (Flores et al., 2004).

Table 5.4. UCM coal quality (courtesy of Usibelli Coal Mine).

PROXIMATE ANALYSIS

	As Received	Dry Basis
Ash	10.7	15.0
Moisture	26.6	
Volatiles	34.0	46.0
Fixed Carbon	28.5	38.7
BTU/lb	7524	10211
Sulfur	0.20	0.28

ASH COMPOSITION

	Dry Basis
Magnesium Oxide	3.32
Phos. Pentoxide	0.36
Sulfur Trioxide	4.41
Potassium Oxide	1.24
Sodium Oxide	0.37
Barium Oxide	0.54
Strontium Oxide	0.19
Manganese Oxide	0.14
Undetermined Oxide	1.11
Base Acid Ratio	0.58
Silica Value	61.56
Silicon Dioxide	42.88
Aluminium Oxide	18.68
Titanium Dioxide	0.85
Iron Oxide	7.12
Calcium Oxide	19.46

ULTIMATE ANALYSIS

	Dry Basis	Dry, Ash Free
Ash	15.0	
Carbon	59.7	69.5
Hydrogen	4.6	5.4
Nitrogen	0.8	1.0
Oxygen	20.0	23.8

ASH FUSION TEMP (°F)

	Average
T250 Temp	2431
Initial Reducing	2224
Soft Reducing	2257
Hemi Reducing	2291
Fluid Reducing	2357

MISCELLANEOUS

	Average
Grindability Index(1)	34
Pyritic Sulfur (AR)	0.03
Organic Sulfur (AR)	0.20
Mercury TCLP	0.0000

Table 5.4. *Continued*

TRACE ELEMENTS (ppm)

Dry Basis

Mercury Total	0.07
Antimony	1.31
Arsenic	2.10
Beryllium	0.43
Lead	5.64
Lithium	4.64
Manganese	118.10
Nickel	11.76
Selenium	1.57
Cadmium	0.84
Silver	N/A
Phosphorus	129.09
Zinc	7.06
Chlorine	15.49
Fluorine	83.36
Chromium	20.27
Copper	20.78
Vanadium	27.48
Barium	533.58
Cobalt	2.90
Molybdenum	N/A
Thallium	N/A
Boron	20.33

Southern Alaska – Cook Inlet Coal Region

Identified coal resource estimates for the Southern Alaska – Cook Inlet coal region (Figure 5.4) vary between 2.9 and 34.3 billion tons. The coals vary from anthracite to lignite. Historical or proposed coal mining areas in the region include the Susitna-Beluga

Coalfield and the Matanuska Coalfield. A supplemental environmental impact statement (SEIS) was filed for a surface mine in Chuitna, located 45 miles west of Anchorage in the Beluga Coalfield (Chuitna Coal Project, 2006). The SEIS describes the coal as 300 million tons of ultra-low sulfur and subbituminous coal. However, the state of the project is uncertain at this time. According to an internet reference (AlaskaCoal.org, 2009), mining permits exist for the Wishbone Hill Mine and Jonesville Coal Mine, both near Palmer. Usibelli Coal Mine (2009) reports that washed Wishbone Hill coal has a Btu/lb of 12,200 with sulfur and ash of 0.4% and 9%, respectively; however, they list reserves as only 15 million tons (washed). Black Range Minerals (2009) lists the coal of its Jonesville Mine as high quality with a Btu/lb value between 10,400 and 13,400 and a sulfur value of 0.3% to 0.4%; it lists the Jonesville resources at 131 million tons. Both Wishbone Hill Mine and Jonesville Mine are close to the Glenn Highway. Table 5.5 lists the coal quality for the Southern Alaska – Cook Inlet coal region.

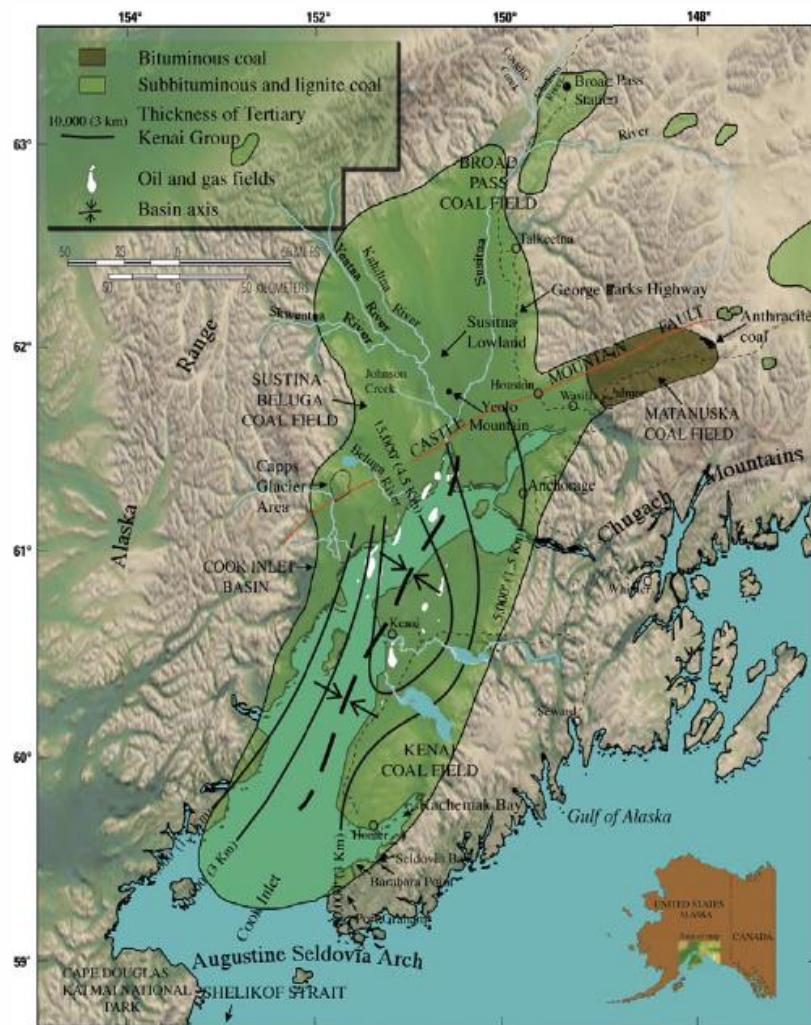


Figure 5.4. Southern Alaska – Cook Inlet region (Flores et al., 2004).

Table 5.5. Coal quality of the Southern Alaska – Cook Inlet region (Flores et al., 2004).

Area	Moisture	Volatile matter	Fixed carbon	Ash yield	Total sulfur	Calorific value Btu per pound
Broad Pass	20–35	27–35	20–28	10–20	0.2–0.4	5,500–7,100
Kenai	20–27	30–38	25–35	3–25	0.2–0.4	6,500–8,500
Matanuska Valley						
Wishbone Hill	3–9	32–45	38–51	4–22	0.2–1.0	10,400–13,200
Chickaloon	1–5	14–24	60–72	5–20	0.4–0.7	11,960–14,400
Anthracite Ridge	3–9	7–11	65–81	7–20	0.2–0.7	10,720–14,000
Susitna Lowland	10–30	28–40	25–45	3–30	0.1–0.7	6,200–9,500

Pollutants in Alaskan Coal

Table 5.6 lists the trace elements from the three coal regions of Alaska. Trace elements from the only coal that is mined in Alaska are given in Table 5.4. These tables, in addition to Tables 5.1, 5.2, and 5.5, demonstrate the low levels of pollutants in Alaskan coal, especially sulfur and mercury. Thus, Alaska as a whole provides a good location for increased coal utilization.

Table 5.6. Trace elements of Alaska's three coal regions, from querying the USGS coal quality database (U.S. Geological Survey, 2004).

	Cook Inlet-Susitna		Central Alaska		North Slope	
	Ave	Sample Count	Ave	Sample Count	Ave	Sample Count
As	5.02	30	5.74	48	3.12	77
Be	0.57	27	0.73	38	0.88	76
Cd	0.10	30	0.55	48	0.07	78
Co	5.56	30	4.27	48	5.89	78
Cr	18.71	30	21.24	47	10.70	78
Hg	0.06	30	0.09	48	0.04	78
Mn	107.63	30	109.00	49	79.42	78
Ni	10.61	30	16.35	49	23.07	78
Pb	3.16	30	4.27	48	5.60	78

Table 5.6. *Continued*

	Cook Inlet-Susitna		Central Alaska		North Slope	
	Ave	Sample Count	Ave	Sample Count	Ave	Sample Count
Sb	0.99	30	1.62	48	0.26	78
Se	0.53	27	3.93	43	0.58	77
Th	3.06	20	2.11	43	2.14	76
U	0.92	30	1.50	48	1.11	77
Cl	110.29	7	95.00	30	100.39	59
F	68.80	30	146.40	48	110.92	78
Ash	14.51	30	11.90	49	9.64	78

Review of Coal Gasification

This section reviews coal gasification from an Alaska coal perspective (whenever possible). Unless otherwise mentioned, the information in this section comes from Higman and van der Burgt (2003).

Basics of Gasification

Higman and van der Burgt (2003) define gasification as the “conversion of any carbonaceous fuel to a gaseous product with a useable heating value.” Since complete combustion results in flue gases that do not have a useable heating value, combustion (or complete oxidation) cannot be (rightly) considered gasification. Broadly, coal gasification involves introducing oxygen (or steam) to combust a small portion of the coal to produce carbon monoxide (CO) and heat. The heat then drives the next set of reactions, where the remaining coal reacts with CO, oxygen, and steam to create syngas, a name for the mixture of CO and H₂. Though other hydrocarbons are also created, given the high temperature and pressures, they can only be present in minor quantities (except methane).

The following relationships generally apply to gasification:

- Gasification is preferably done at pressure. However, syngas (CO + H₂) generation decreases with increasing pressure of gasification (at fixed temperature), unlike the major by-products water, CO₂, and methane.

- As temperature increases (at a fixed pressure), CO generation goes up, while H₂ is not affected. Water, CO₂, and methane decrease, and at about 1300°C, they are almost negligible. Oxygen demand increases with temperature.

There are three major coal gasification technologies (with a multitude of variations of each); they are described in the sections that follow.

Moving/Fixed-Bed Gasifiers

Moving/fixed-bed gasifiers are the oldest forms of gasifiers. This type of gasifier is used around the world for a variety of downstream products, including synthetic fuel (synfuel). In the Lurgi type of moving/fixed-bed gasifier (the most common type), coarse coal is fed into the gasification chamber from the top. Blast (typically oxygen and steam) is introduced at the bottom. Produced syngas leaves at the top, while ash/slag leaves at the bottom (Figure 5.5).

The gasifier can be thought of as having four zones that represent the various stages of gasification. Upon entry, coal dries because of hot gases. When the temperature rises sufficiently, coal devolatilizes; that is, the volatiles in the coal are released, leaving behind char. The presence of the drying zone allows even high-moisture coals (such as low-rank coals) to gasify. The char undergoes combustion in the bottom zone, providing the thermal energy necessary for gasification. Movement of the coal through the chamber is slow; residence time is up to an hour (Krigmont, n.d.). In “dry ash” gasifiers, the gasification temperature is kept below the melting point of ash, while in “slagging” gasifiers, the gasification temperature is above the melting point of ash. Slagging gasifiers consume less coal, steam, and oxygen for the same amount of syngas, though throughput is typically low (Gasification, 2009). Additionally, there are ash-related benefits: easy removal of molten slag and easy handling of solid/glassy slag and non-leachable character of ash (Seed et al., 2007). The feed, however, has to be non-caking and have good mechanical strength and a low ash-melting point to be a perfect fit for slagging gasifiers (Gasification, 2009), though exceptions exist. Tapp et al. (2004) contend that ash fusion temperatures are critical, as they have considerable influence on the performance of the slagging gasifier. A downside with the fixed-bed gasifier is its moving parts (such as the stirrer and the rotating grates for ash in dry-ash gasifiers) inside the gasifier. These parts are often the reason behind the high maintenance requirements for this type of gasifier. For example, the stirrer that is used to ensure uniform distribution of coal in the bed can become clogged for caking coals at temperatures below the melting point of coal. Tables 5.7 and 5.8 summarize typical performance of moving/fixed-bed gasifiers.

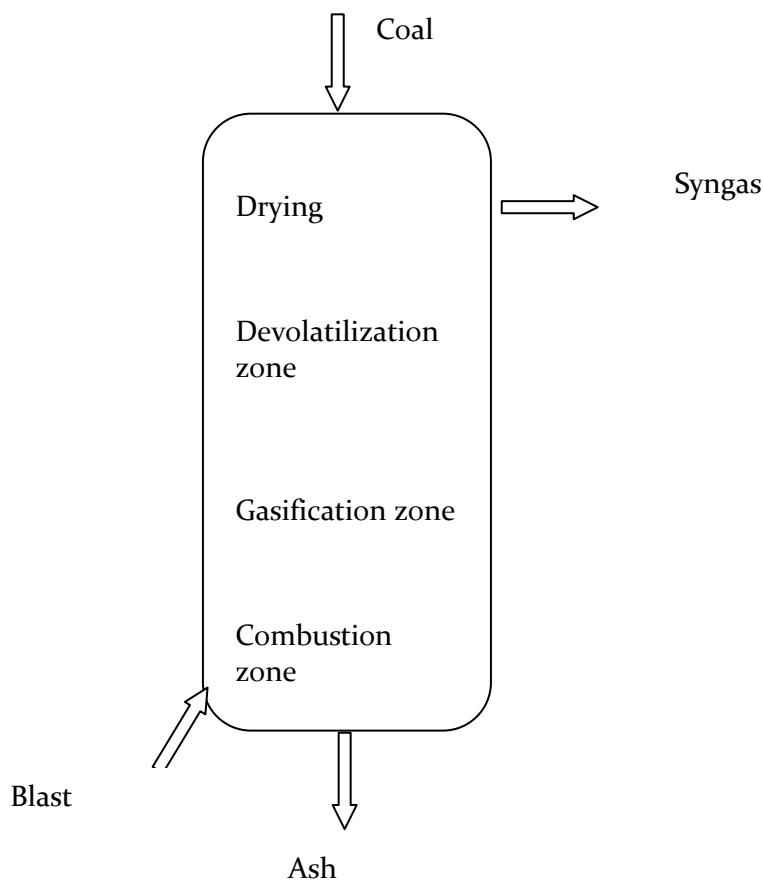


Figure 5.5. Lurgi gasifier (after Higman and van der Burgt, 2003).

Table 5.7. Performance of Lurgi moving/fixed-bed dry-ash gasifier (Higman and van der Burgt, 2003).

	Coal Type	Lignite	Bituminous
Dry raw gas composition	CO ₂ +H ₂ S, mol%	30.4	32.4
	CO, mol%	19.7	15.2
	H ₂ , mol%	37.2	42.3
	CH ₄ , mol%	11.8	8.6
	C _n H _m , mol%	0.4	0.8
	N ₂ , mol%	0.5	0.7
Feed Components per 1000 Nm ³ CO+H ₂	Coal maf, kg+	950	750
	Steam, kg	1180	1930
	Oxygen, Nm ³⁺⁺	170	280

+ maf is moisture and ash free

++ Nm³ is normal cubic meter or volume at 1.0132 bar and 30°C

Table 5.8. Comparing dry ash and slagging gasifiers (Higman and van der Burgt, 2003).

Gasifier		Lurgi Dry Ash	British Gas/Lurgi Slagging
Dry raw gas composition	CO ₂ , mol%	30.9	3.5
	CO, mol%	15.2	55
	H ₂ , mol%	42.2	31.5
	CH ₄ , mol%	8.6	4.5
	C _n H _m , mol%	0.8	0.5
	N ₂ , mol%	0.7	3.3
	H ₂ S+COS, mol%	1.3	1.3
	NH ₃ , mol%	0.4	0.4
Feed Components per 1000 Nm ³ CO+H ²	Coal maf, kg+	750	520
	Steam, kg	1930	200
	Oxygen, Nm ³ ++	280	230

+ maf is moisture and ash free

++ Nm³ is normal cubic meter or volume at 1.0132 bar and 30°C

Fluid-Bed Gasifier

With the fluid-bed gasifier, the coal and the gas mixture are designed to behave as a fluid. When gas velocities are low, there is a distinct separation between the dense (coal + gas) phase or “bed” and the gases. As gas velocities increase, the reactor first changes to a circulating fluid bed (CFB) and then to a transport phase, where the solids are fully carried out of the reactor by the gas. Figure 5.6 shows three distinct types of reactors. Ash is removed either at the bottom of the reactor or at the top, using cyclones.

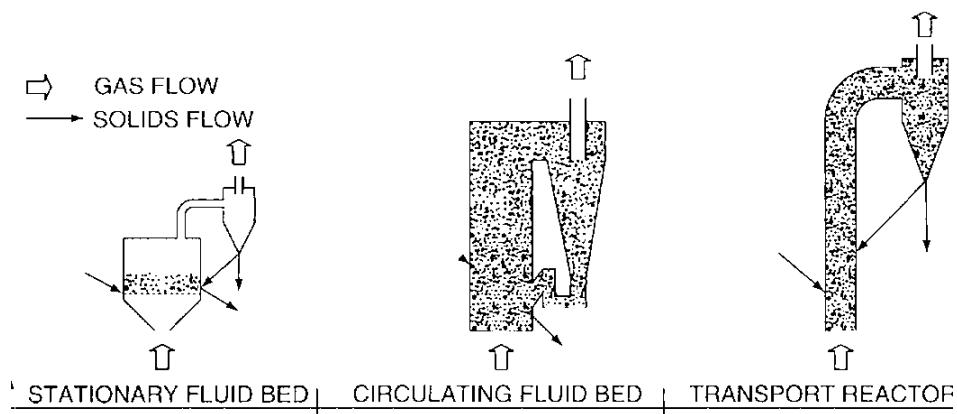


Figure 5.6. Different types of fluid-bed reactors (after Higman and van der Burgt, 2003).

Particle size is key to the successful operation of fluid-bed gasifiers (though not critical for the CFB sub-type). While large particles cannot form a bed, too-small particles result in the coal being carried out of the reactor. Feed size is usually smaller than 0.4 inches (10 mm) with minimal fines. Since particle size changes during gasification, this type of gasifier requires close monitoring of the fluid bed for efficient operation.

Ash properties also affect the performance of fluid-bed gasifiers. If ash particles soften and agglomerate, they fall out, making ash removal a challenge. Thus, low-rank coals make good feed, since their increased reactivity allows them to be gasified at temperatures below ash-melting points. Low-temperature gasification, unfortunately, has the side effect of producing more tar, partly because slow heating releases more volatiles and partly because there is less thermal cracking of tars at low temperatures. Tar production is lower in CFB gasifiers, however, since by design the coals are exposed to excellent heat-transfer rates.

Another ash issue with fluid-bed gasifiers is the leachable form of the ash produced. This problem is especially pronounced when limestone is added to aid sulfur removal, since there is always some unconverted lime. Agglomerating fluid-bed gasifiers, meant for higher-rank coals and designed to agglomerate a portion of their ash, have fewer leachable ash problems.

Other problems with this type of gasifier include reduced carbon conversion and the need for insulating bricks. Compared with other types of gasifiers, where 99% of the carbon is converted to gas, the carbon conversion with this type of gasifier barely reaches 97%. There are two major reasons for this difference: First, dissimilar particles, because of their shape and size, have different residence times in the reactor, resulting in varying carbon conversion rates. Second, even if the unconverted carbon is captured using cyclones and converted using incoming blast, gasifying it is difficult because of temperature

restrictions. Insulating bricks are needed because, despite low gasification temperatures, temperatures are high enough that insulating bricks are preferred. Reactor design gets complicated because of this, especially when reactor shapes are complex (such as in circulating fluid beds). Table 5.9 lists the performance characteristics of a fluid-bed gasifier.

Table 5.9. Performance of a fluid-bed gasifier (Higman and van der Burgt, 2003).

Coal Type		Lignite	Bituminous	Bituminous
Blast Type		O ₂ / Steam	O ₂ / Steam	Air
Temperature, °F (°C)		1832 (1000)	1832 (1000)	1832 (1000)
Pressure		30	30	30
Dry raw gas composition	CO ₂ , mol%	6.2	5.3	1.9
	CO, mol%	56.7	52.0	30.7
	H ₂ , mol%	32.8	37.3	18.7
	CH ₄ , mol%	2.6	3.5	0.9
	A, mol%	0.6	0.6	0.6
	N ₂ , mol%	0.9	1.0	47.0
	H ₂ S, mol%	0.2	0.3	0.2
Feed Components per 1000 Nm ³ CO+H ₂	Fuel maf, kg+	1317	564	100
	Steam, kg	26	260	24
	Oxygen, Nm ³⁺⁺	461	260	266

+ maf is moisture and ash free

++ Nm³ is normal cubic meter or volume at 1.0132 bar and 30°C

Entrained-Flow Gasifier

With the entrained-flow gasifier, the coal and the blast react while flowing together through the reactor at high speed. To ensure gasification in the few seconds of residence time, the feed is typically ground to under 100 microns in size and the gasification temperature is high (upwards of 2,282°F or 1,250°C). The high gasification temperature results in pure syngas, since tars and other contaminant hydrocarbons cannot withstand such high temperatures. Important characteristics of the gasifier include ability to accept most coal types and high oxygen consumption. Oxygen consumption is extremely high for high-moisture/ash coals, making them almost unsuitable for this type of gasifier, though two-stage gasifiers (discussed next) are able to handle high-moisture coals. Most of the generated ash leaves as inert molten ash since the gasification temperature is above ash melting point; the rest leaves as fly ash in the gas.

There are two major types of entrained-flow gasifiers: single-stage and two-stage. In the two-stage gasifier, gasification takes place in two separate stages. Typically, the first stage is slagging (high temperature), where a portion of the fuel is partially oxidized. The heat from this stage provides thermal energy for the second stage. Two-stage gasifiers typically have a higher efficiency for the same feed type (Table 5.10). However, unlike the highly pure gas produced from single-stage gasifiers, the lower temperatures in the second stage result in some tars, methane, etc., in the product of the two-stage gasifiers.

Table 5.10. Efficiencies of various entrained-flow gasifiers (Higman and van der Burgt, 2003).

Feed	Syngas Cooling	Gasifier Conditions	IGCC ⁺ Efficiency (LHV)
Slurry	Water quench	64 bar, 1500°C	37.8
Slurry	Gas quench	64 bar, 1500°C	43.6
Slurry (320°C)	Gas quench	64 bar, 1500°C	48.8
Dry	Gas quench	32 bar, 1500°C	50.0
Dry	Two-stage gas quench	32 bar, 1500/1100°C	50.9

⁺ IGCC: Integrated Gasification Combined Cycle

Two recent CTL studies for two different locations in Alaska (Healy and Fairbanks) have considered only entrained-flow gasifiers (Bibber et al., 2007; Dover, 2008). The CTL plant in Healy was designed to produce 14,640 barrels per day (consuming 11,000 tons/day of coal), while the CTL plant in Fairbanks was designed to produce 20,000 to 40,000 barrels per day (consuming 17,000 to 34,000 tons/day of coal). The quality of syngas, which is important for its downstream conversion to synthetic fuels, is one reason why entrained-flow gasifiers were selected. Note that other types of gasifiers could also be used (as is done by Sasol, a major synfuel producer that uses fixed-bed gasifiers) to produce syngas for synfuels.

Dover (2008) was charged with conducting a preliminary feasibility study for a CTL plant in Fairbanks. This study only considered those entrained-flow gasification licensors that had commercial operations: Shell Coal Gasification Process, Uhde, Siemens, ConocoPhillips, and GE. Additionally, plasma gasification and coal-biomass co-gasification were considered. The study did not make a recommendation. On the other hand, Bibber et al. (2007), who studied a CTL plant for Healy, considered only ConocoPhillips technology.

Contaminant Issues with Gasification

Coal gasification, like any large industrial process, has an environmental impact. The impact can be in many forms such as emissions (solids, liquids, or gaseous) discharged by

the plant and resource consumption such as water. Given the scope of the study, the discussion below is limited to the role of contaminants/emissions alone.

Gaseous Emissions

Dover (2008) lists emissions sources in the proposed Fairbanks CTL plant: coal drying vent, air separation unit off-gas, upgrading heater vent, fired super heater vent, heat recovery steam generator vent, deaerator off-gas, and steam methane-reforming unit air-heater vent (if natural gas is to be co-fed with coal). Gaseous emissions are of two types: organic and non-organic. The organic emission that most affects air permits is CO, though impending greenhouse gas legislation may change that and make CO₂ and CH₄ emissions just as important (or more). The major non-organic gaseous emissions are those based on sulfur, nitrogen, trace elements, and particulate matter (PM). Many of the pollutants emitted by gasification are either cleaned or converted prior to finally being emitted from a CTL plant. Note that since gasification typically occurs under pressure, the product gas stream is significantly smaller in volume than when coal is combusted under normal pressure (as in pulverized coal power plants), resulting in pollutants being emitted at a high concentration, which makes gas cleanup easy (Childress, 2002). Thus, final emissions are based as much on the downstream cleaning technology as on the process that generates the emissions. It is no surprise then that IGCC (integrated gasification combined cycle) power plants have been found to have significantly lower emissions (NO_x, SO_x, PM, CO, and volatile organic compounds such as CH₄) than pulverized coal power plants.

The extent and nature of organic emissions from gasification is dependent on gasification technology and downstream processes, since one form can be converted to another if it is desirable to do so. Gasification technology makes it easy to suppress and/or capture organic emissions. Dover (2008) estimated CO₂ generation of 1,194 tons/hr for production of 40,000 barrels per day of synfuel at the Fairbanks CTL plant, with CO₂ capture estimated at 82.1%; that is, CO₂ emissions are expected to be 214 tons/hr. For the Healy CTL, Bibber et al. (2007) did not estimate CO₂, but estimated CO and volatile organic compounds (typically includes CH₄) emissions of 22 tons per year and 14 tons per year, respectively.

The common non-organic emissions of interest are NO_x, SO₂, PM, and trace elements. Diaz-Somoano and Martinez-Tarazona (2003) report that, while some trace elements vaporize and end up mostly in product gas streams (such as Hg [mercury], Se [selenium], and B [boron]), some do not vaporize and, thus, show up almost entirely in the slag (such as Mn [manganese]). Some trace elements, such as As (arsenic), Cd (cadmium), Sb (antimony), Pb (lead), and Zn (zinc), show up in both product gas and slag. The authors also report that trace element-vaporizing characteristics in coal gasification are different from those in coal combustion. For the Healy CTL plant, Bibber et al. (2007) expect NO_x,

SO₂, and PM emissions of 431, 161, and 76 tons per year, respectively; they also estimate Hg and Pb emissions to be insignificant, that is, less than 1 ton per year. In their study, they assume that the CTL plant would contain common contaminant-control technology. Dover (2008) mentions NO_x as a potential operational issue with the gas turbine in the Fairbanks CTL, since high H₂ content in the gas (with the resultant high flame speed) would make low NO_x combustion difficult.

Another issue that can impact a site is water vapor emissions. In extremely cold climates such as Fairbanks and Healy, the relatively benign water vapor emissions can cause visibility problems (from ice fog) for nearby areas. If a CTL plant is located inside an air base, this can affect its mission. Neither Dover (2008) nor Bibber et al. (2007) provide estimates of emitted water vapor.

Solid Emissions

The major solid emissions from gasification are bottom ash and fly ash. Bottom ash is emitted as liquid slag in (high temperature) slagging gasifiers and as dry ash in (low temperature) dry ash gasifiers. Dover (2008) estimated that the Fairbanks CTL would produce about 3,960 tons of slag per day and 2,020 tons of fly ash per day for a 40,000 bbl/day (barrel per day) plant. For the smaller Healy CTL plant (14,640 bbl/day), Bibber et al. (2007) estimated slag production at 1,228 tons per day. The ash will typically contain most of the contaminants present in the feed coal. In this aspect, the slagging gasifiers have a distinct advantage since the slag is typically inert and non-leachable. Both slag and dry ash (depending on its nature, especially leachability) can have a commercial value. However, if the dry ash has no local market, then its disposal can pose a challenge. The same is true for slagging gasifiers, though because of their significantly smaller volumes and inert nature, it is less of a problem. Bibber et al. (2007) proposed that ash from the Healy CTL plant be disposed of at the mine.

Besides ash, other solid wastes could include sulfur, wastewater-treatment sludge, and those associated with Fischer-Tropsch processes (for a CTL plant), such as used catalysts and spent filter elements.

Liquid Emissions

Bibber et al. (2007) list a variety of possible water discharges including storm water, slag storage facility effluent, cooling water blowdown, and reverse osmosis among others. They did not estimate water discharge quantity and quality. Note that most water is recycled, with water that is discharged typically cleaned to regulatory standards prior to discharge. Prior to cleaning, most process waters contain heavy metals and other contaminants.

Broader Role of Contaminants

Contaminants and emissions affect CTL plants beyond the legal/permit requirements. Mineral matter in coal can wreak havoc on refractory liner life, which can severely impact operating costs, especially in Alaska, which is logistically challenged. For example, refinery residue gasifiers only require minor repairs at 16,000 hours, while coal gasifiers, due to ash content of coal, only last 6–18 months. Similarly, coal gasifier burners have one-fourth the life of resid burners. Thus, it is not sufficient to look at contaminants that are finally emitted; one must also look at damage done to the gasification and downstream equipment before these contaminants are captured. This is especially so since reliability of equipment in gasification-based technologies can often be a concern.

A solution to contaminant-caused problems may be ultra cleaning of coal (UCC) prior to gasification. This topic is presented next.

Ultra Cleaning of Coal

Steel and Patrick (2001) ultra-cleaned high-volatile bituminous coals from the United Kingdom by leaching particles smaller than 500 microns with aqueous HF followed by aqueous HNO₃. The two-stage leaching process reduced the ash content of the coal from 7.9% to 0.6%. The sulfur content of the coal was reduced from 2.6% to 1.4%. The ash that remained after the leaching consisted mostly of FeS₂ (pyrite). When a similar process was repeated on the same type of coal with particles smaller than 62 microns (Steel and Patrick, 2003), the ash content was reduced from 5% to 0.2%, while sulfur was reduced from 2.4% to 1.3%. Only Fe (iron) remained in the mineral matter. The process also increased the nitrogen and oxygen content. In a different study, Steel et al. (2001a, 2001b, and 2001c), who leached the ash from Australian coal using HCl and HF, found that HCl dissolved most of the Ca (calcium), Mg (magnesium), Na (sodium), and Fe and some of Al (aluminum), K (potassium), and Ti (titanium) from the ash, while the HF dissolved most of the Al, K, and Si (silicon) from the ash.

While UCC demonstrates the ability of chemical leaching in removing a majority of the mineral matter from coal, it is important to know how it affects the combustibility of coal. Rubiera et al. (2003) studied the combustibility of a high-volatile coal (6% ash) ultra-cleaned (to 0.3% ash) by leaching it with HF and HNO₃. They found that the combustion efficiency improved and that burnout levels increased.

Probably based on similar findings, Felix Resources (2009) has taken UCC technology from the laboratory to pilot scale to develop a product that can be directly gasified (Figure 5.7). The company claims that its patented technology cleans the coal to 0.1% ash levels. In the process used by Felix Resources, alkali leaching makes the mineral matter soluble, which is then dissolved by acid leaching and precipitated as gypsum and aluminum

silicates that are safely disposable or are of interest to the construction and ceramics industry. Their UCC product (Table 5.11) is designed to be combusted in a gas turbine for electricity generation.

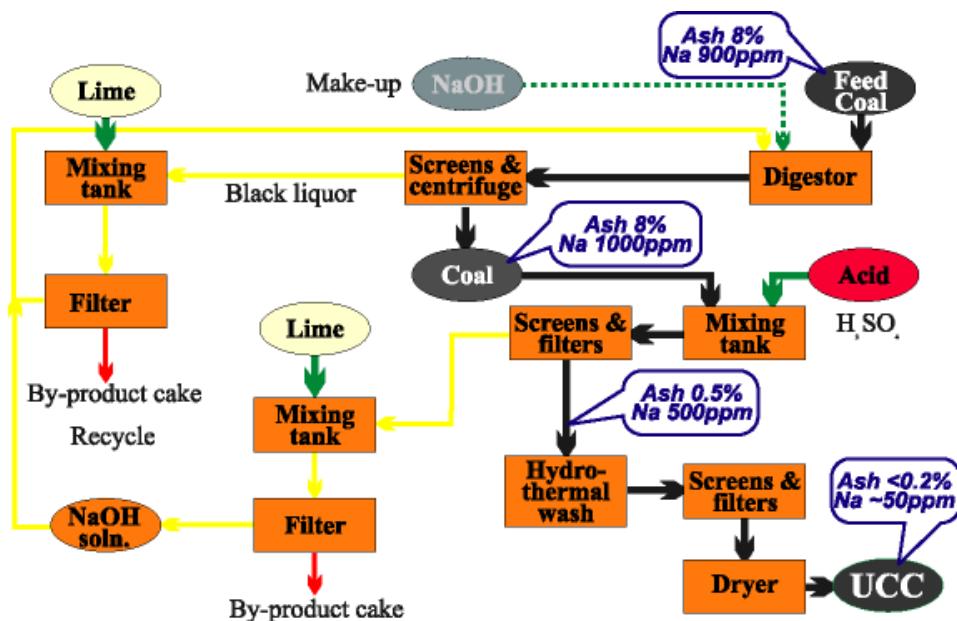


Figure 5.7. Felix Resources' ultra clean coal technology (White Mining, 2009).

Table 5.11. Before and after ultra cleaning of coal (White Mining, 2009).

Property	Feed Coal	UCC (Laboratory)
Total ash	8.3%	0.15%
Ash particle size	-	< 5µm
Inorganic Content of the Coal (ppm)		
Si	24,800	35
Al	12,300	8
Ti	733	477
Fe	3,383	34
Ca	437	22
Mg	431	5
Na	919	58
K	464	9
P	86	3
Mn	13	0
V	29	12
Ash Fusion Temperature IDT		
	> 1500 °C	> 1500 °C

Silica in coal ash is known to significantly damage the Al₂O₃ (aluminum oxide) hot face of refractory in weeks, though chromium oxide and zirconium oxide refractories can handle silica a little better. The 99.99% reduction in silica from UCC is noteworthy, therefore. Similarly, the reduction in mineral matter should significantly improve burner life and other downstream processes.

Questions Regarding UCC

There are other benefits to UCC beyond those discussed in the previous section. A UCC plant located at a mine-mouth in Healy would vastly reduce the tonnage of feed transported to Fairbanks, which would greatly reduce the footprint of a CTL plant. It would also ease the burden on the Alaska Railroad. However, since a UCC product is fine and difficult to ship, it would need to be briquetted and probably re-ground prior to gasification. Efficiencies could be gained vis-à-vis briquetting and re-grinding (though transportation and footprint efficiencies would be lost) if the UCC plant were located by the CTL plant, since the already wet, fine product from UCC could be slurried and piped to the gasifier. Of course, efficiencies could be gained on all three fronts (transportation, footprint, and ease of feed) if the CTL and UCC plants were located by a coal mine.

Despite the many demonstrated and potential benefits of UCC, major questions remain concerning its application in Fairbanks and Alaska:

1. Will the UCC technology work for Alaska's low-rank coals?
 - a. There are two parts to this question:
 - i. Will ultra cleaning result in a dramatically improved product? Will the process have to be modified for Alaska's low-rank coals?
 - ii. Will the UCC product be suitable for coal gasification? It is important to note that Felix Resources intends to directly burn its product in a gas turbine and not gasify it for CTL. Combustion and gasification are not the same thing, and therefore, gasification potential of ultra-cleaned coal should be investigated.
 - b. Will the UCC by-products remain benign?
2. What will UCC cost?

Conclusions

Alaska, which contains 15% of the world's coal resources, has three major coal regions (north, central, and south), consisting of a variety of coals (anthracite to low rank). The lone operating coal mine in Alaska is the Usibelli Coal Mine, which is located in Healy and mines high-volatile low-rank coal. Alaska's coal (including UCM coal) is very good from an environmental perspective, consisting of low amounts of sulfur (especially pyritic sulfur), metallic trace elements, and nitrogen.

Gasification choices for Alaskan coal include fixed-bed gasifiers, fluid-bed gasifiers, and entrained-flow gasifiers. Most of these gasifiers can be dry ash or slagging, with slagging gasifiers having distinct advantages, such as inert slag and pure gas, though they also have the significant disadvantage of cost (because of high-temperature gasification). Recent CTL studies (for Fairbanks and Healy) investigated only entrained-flow gasifiers, not the feasibility of other gasifiers.

The major gaseous emissions from a CTL plant would consist of SO_x, NO_x, particulate matter, CO, and CO₂. Gaseous emissions will likely contain some amount of trace elements. Given the cold climate of Alaska, particularly Fairbanks, water vapor emissions may be critical because of their impact on visibility. The major solid effluents would be dry ash or slag, and fly ash. Ash disposal can be a problem, especially if it is leachable. Slag is much easier to handle because it is inert and volumetrically smaller than dry ash. Water (from a variety of processes including gas cooling), following purification, will be the major liquid effluent.

As evident from comparing coal-fed gasifiers with resid gasifiers, pollutants in coal affect gasification processes not only as emissions but also as causes of major maintenance problems prior to their exit from the process. Ultra cleaning of coal could be a solution to pollutant-related problems such as high operating costs from the reduced life of gasification and downstream equipment. Ultra cleaning of coal could also have associated benefits such as reducing the footprint of a CTL plant. However, there have been no studies on ultra cleaning Alaskan coal to answer questions about the technical feasibility of the process and costs.

It is recommended that studies be conducted to examine (a) applicability of all types of gasifiers through simulation studies and (b) applicability and cost of ultra cleaning of coal for a CTL plant.

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CHAPTER 6

Modeling of Atmospheric Dispersion of Water Vapor and Other Pollutants and Related Visibility Concerns at Eielson Air Force Base

by Martin Stuefer

Introduction

The Eielson heat and power plant emits gases and particles directly into the atmospheric boundary layer of the military base. In winter, the atmospheric dispersion of emissions is suppressed by high atmospheric stability. Scattering and absorption of light by gases and particles in the atmosphere may cause significant reduction in visibility. Water vapor as a major by-product of the gasification process reduces visibility in various ways; in winter, it condenses and freezes, creating ice fog in the power plant's vicinity. Gaseous water vapor absorbs light directly, and water vapor may affect the scattering properties of particles (aerosols) by modifying optical cross sections. Sources of elemental carbon particles are combustion products from power plants or domestic fuel burned during the cold season. Large amounts of water vapor cause frequent saturation of the lower atmospheric boundary layer. A high concentration of ice particles results in ice fog and low visibility, seriously affecting airport operations, with obvious direct consequences to the Air Force Base. This chapter describes a possible system that would model the effects of power plant water vapor emissions on visibility.

Power Plant Emissions into the Atmosphere

The Coal Heating and Power Plant at Eielson Air Force Base

The Eielson heating and power plant (referred to as Eielson HPP), with a nominal capacity of 25.0 MW (megawatts), is located at 64.67045°N and 147.0752°W (2258 Central Ave., Ste. 100, Eielson AFB, AK 99702) (Figure 6.1). The plant burns about 196,500 tons of coal per year—approximately 400 tons per day in the summer and 800 to 900 tons per day in the winter. In 2005, 85,549 MWh (megawatt hours) of electricity was produced. The burning of coal produces major amounts of carbon dioxide (CO₂), sulfur dioxide (SO₂), and nitrogen oxides (NO_x). These gases are vented from the boiler. Fly ash, which is very light, exits the boiler along with the hot gases. An electrostatic precipitator (a huge air filter) removes 99.4% of the fly ash before flue gases are dispersed into the atmosphere. Plant emissions into the atmosphere are summarized in Table 6.1.



Figure 6.1. LANDSAT image showing the power plant with coal reservoirs and parts of the cooling ponds.

Table 6.1. Emissions data.

Emissions	Amount (tons/year)	Year
PM ₁₀	6.3	2007
CO	94.5	2006
CO ₂	200.6	2006
SO ₂	280.6	2007
NO _x	330.6	2007
VOC	4.4	2007

Water vapor release from the power plant is estimated with a high degree of inaccuracy, since (1) there is condensation of vapor produced by coal combustion, and (2) hot water is released to the cooling pond near the plant. The coal that is used (from Healy) typically has 28% moisture (mass of moisture/mass of as-received fuel) and 4.5% hydrogen on a dry basis, amounting to total water vapor emissions of 57.16% of the total coal burned (mass of

moisture in relation to mass of dry fuel), considering the molecular weight of water compared with the molecular weight of hydrogen. (Special thanks to Dennis Witmer from the University of Alaska Fairbanks, Arctic Energy Technology Development Laboratory for his contribution in estimating these emissions.) For a maximum coal usage of 900 tons per day, water vapor emissions of 514.4 tons per day (21.4 tons per hour) would be expected. However, combustion gases are bypassed to the condenser before entering the “bag house,” where fly ash and bottom ash is separated. Only some of the water vapor is released through the stack to the atmosphere; hence, water vapor emission rates of 21.4 tons per hour serve as the upper limit for water vapor emissions from coal burning in the winter.

Artificial heating of the pond keeps most of the water surface unfrozen over the winter months. Evaporation from lakes differs significantly from evaporation from land surfaces. Strong water vapor gradients between the saturated air near the above-freezing surface of the pond and the previously relatively dry, cold air in the atmospheric boundary layer cause significant evaporation of water. Vertical water vapor flux in the atmospheric boundary layer is typically obtained with eddy correlation methods by measuring vertical components of near-surface wind, fluctuations of the partial density of water vapor, and air density. In the absence of such measurements, there are empirical approaches to evaporation estimation. Priestley and Taylor (1972) have calculated evaporation (E) according to

$$\lambda E \rho_w = \alpha [\Delta / (\Delta + y)] (Q^* - Q_g) \quad (1)$$

where α is an empirical constant that relates actual to equilibrium evaporation ($\alpha = 1.0$ for equilibrium evaporation), Δ represents the slope of the saturation vapor pressure versus temperature curve, which may be calculated as a function of air temperature (Dilley, 1968), y is the psychometric constant depending on the atmospheric pressure (hPa °C⁻¹), Q^* is net radiation (W m⁻²), Q_g is the subsurface-heat flux or the amount of energy stored in the water column (W m⁻²), and λ is the latent heat of vaporization (J kg⁻²). Priestley and Taylor (1972) found that, for saturated surfaces, α averages 1.26. The subsurface-heat flux is obtained as a function of changes in water temperature over time (δT_w), a typical length below the water surface (d_{bws}), and the density (ρ_w) and specific heat of water (C_w):

$$Q_g = \delta T_w d_{bws} \rho_w C_w \quad (2)$$

For the subarctic setting of the power plant, we can assume that $Q_g \gg Q^*$, reducing Equation (1) to

$$\lambda E = -\alpha [\Delta / (\Delta + y)] Q_g \quad (3)$$

Gibson et al. (1996) derived typical values of between 3.2 and 2.5 mm d⁻¹ for evaporation from a small lake in the Canadian Arctic during summer periods. We derive an approximate upper limit of evaporation from the Eielson cooling pond that amounts to 3.5 mm d⁻¹ using high estimates of the subsurface-heat flux and Δ of 0.03 hPa C⁻¹. With a pond size of 26 acres, we derive a maximum water vapor emission due to evaporation of 15.3 tons/hour. The sum of maximum water vapor emissions due to coal burning (21.4 tons/hour) and evaporation (15.3 tons/hour) results in total maximum Eielson HPP water vapor emissions of 36.7 tons/hour.

Coal-to-Liquids Plant Emissions

Three different coal-to-liquids (CTL) plant scenarios are studied: (1) a 20,000 bbl/day (barrels per day) plant using coal as a feedstock; (2) a 40,000 bbl/day plant using coal as a feedstock; and (3) a 40,000 bbl/day plant using coal and natural gas as feedstock. Carbon dioxide and water vapor emissions are derived from the Hatch FEDC CTL FEL1 Study (Drover, 2008). Depending on the scenario, significant different CO₂ and water vapor emissions are derived (Table 6.2).

Table 6.2. CTL emissions summary.

	Case 1	Case 2	Case 3
CO ₂ (St-CO ₂ /hour)	130.5	261.0	448.2
H ₂ O Vapor (tons/hour)	226.8	453.6	171.3

Visibility Statistics

Power plant water vapor emissions can cause considerable ice fog and related visibility problems. The phenomenon occurs when the ambient temperature is such that water vapor in the gases nucleates and freezes on condensation nuclei to form small ice crystals that have no appreciable settling velocity, thus forming a dense blanket of ice fog. Visibility limitations due to ice fog regularly restrict operations at Eielson airport (PAEI) in the winter. Ice fog usually occurs at temperatures below -30°C, and increases in frequency with decreasing temperature until it is regularly present near a source of water vapor at an air temperature of -45°C. Main water vapor sources at the Eielson Air Force Base are emissions due to combustion from the HPP, steam emitted directly through the power plant stacks, and water vapor released at the surface of the power plant cooling ponds.

Meteorologists at PAEI weather station operations have to predict visibility, and realize ice fog as a major challenge in their work. A chart has been developed to support “visibility” decision-making. A preliminary study, under the guidance of the former Eielson chief of weather station operations, Bradford Sipperley, resulted in a chart showing visibility in ice fog as a function of time (during the day) and temperature (all months) (Figure 6.2). The study resulted in 80% probability for visibility values of less than 2 miles at temperatures below -40°C (-40°F).

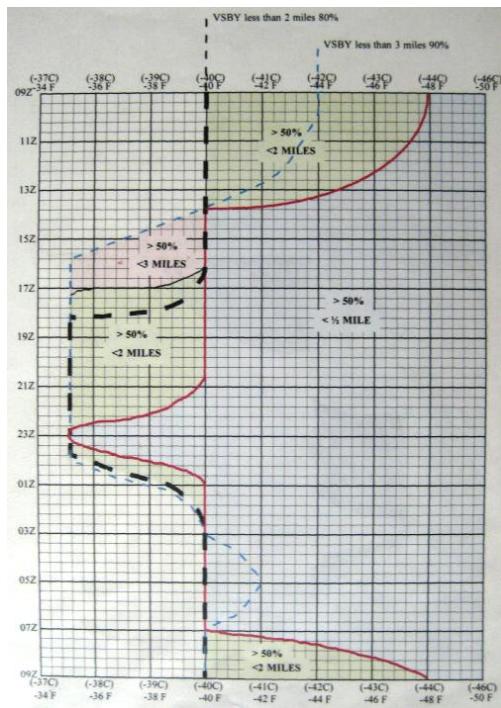


Figure 6.2. Visibility in ice fog as a function of time and temperature (all months) (courtesy of Eielson Air Force Base weather station operations).

We analyzed Aviation Routine Weather Reports (METAR) from PAEI for the winter months of November to March for the years 2003 to 2009 (17,445 observations). The observations were used to derive visibility statistics. Restricted visibility with less than one statute mile occurred on 6.25% of all days; 16.31% of all observations fell below the threshold of 5 statute miles. Worst conditions occurred during the month of January, when visibility was less than one-half mile on an average of 5 days per month. About 63% of these days were clearly confirmed (in METAR) as ice fog. The statistics also show a strong dependence of PAEI visibility on temperature and time of day (daily cycle). Figure 6.3 shows an example of hourly visibility and temperature measurements for the short period of 20 to 23 February 2007. A wide temperature range of -20°C to -43°C was

observed during these 3 days, and extreme values of low visibility and low temperatures coincide significantly for the same period. The METAR data clearly confirm that low visibility due to ice fog seriously affects PAEI operations. This study aims to quantify the influence of water vapor released from the existing Eielson HPP on ice fog formation. In addition, similar model estimates are pursued for the various CTL configurations (compare Table 6.2).

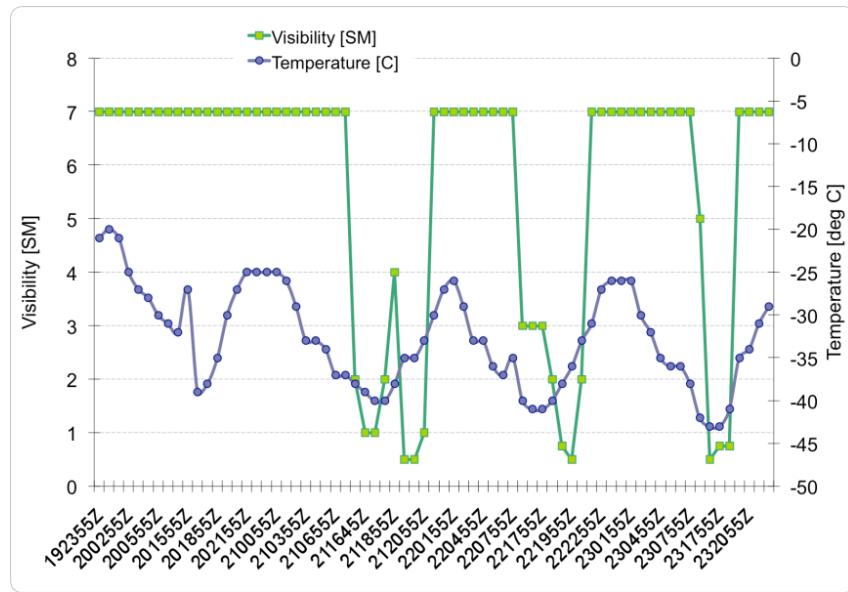


Figure 6.3. METAR measurements of temperature versus visibility during a 3-day test period in February 2007.

Modeling Methods

WRF/Chem

Preliminary air quality modeling studies usually involved decoupled treatment of the physics and chemistry that characterize atmospheric dispersion of anthropogenic emissions and numerical weather prediction. Consequently, inaccurate handling of atmospheric processes and loss of important feedback processes between atmosphere and pollutants might have resulted. In recent years, numerous scientists collaboratively developed the state-of-the-art Weather Research and Forecasting (WRF) model (Michalakes et al., 2000; Skamarock et al., 2005). The architecture of WRF allows its use as a research tool as well as an operational weather forecast model. The National Weather Service and forecast offices all over the world utilize the model extensively. The WRF is a non-hydrostatic atmospheric model with several dynamic cores; the coordinate system fully conserves mass fluxes. Conservation of fluxes is important for air quality models;

hence, WRF has been recognized as an ideal platform to implement chemistry for next-generation air-quality prediction systems (Grell et al., 2005). WRF/Chem, which resulted from implementation of numerous chemical modules in WRF, predicts trace gas and particulate dynamics online with the meteorological fields of the WRF model, and allows for full interaction of chemical transport processes and weather. The term *online* means that coupling between chemistry and aerosols is treated in the model at identical grid cells and time intervals. Errors due to temporal and spatial interpolation are eliminated.

Advanced chemistry modules implemented in WRF/Chem include modeling of gas-phase chemistry and aerosol, as well as their feedback to the weather. WRF/Chem module examples are the Regional Acid Deposition Model, version 2 (RADM₂) (Stockwell et al., 1990) for gas-phase chemistry including photochemistry, or the Dudhia (1989) radiation scheme, which describes a parameterization for aerosol to shortwave radiation feedback processes. WRF/Chem can be directly initialized with known power plant emissions and background aerosol, and meteorological fields available from NOAA.

Anthropogenic background emission data from nearby cities are included in the model. WRF/Chem calculates dispersion of fine particulates (PM_{2.5} and PM₁₀), dust, black carbon (BC), organic carbon (OC), SO₂ and dimethyl sulfide (DMS), as well as hydroxide (OH), O₂H₂, and nitrates (NO₃) from the Goddard Global Ozone Chemistry Aerosol Radiation and Transport (GOCART) model, which has been implemented optionally.

Visibility

Visibility can be (1) derived empirically from temperature, time (compare Figure 6.3), and concentration of atmospheric pollutants (such as ice crystals), or (2) calculated as a function of backscatter coefficient, aerosol size, and number. Even today, lack of knowledge of relevant atmospheric, hydrological, and chemical fog processes inhibit successful ice fog forecasting. For this study, we use estimated power plant emissions from water vapor to initialize the atmospheric dispersion model and further derive ice particle concentrations on either end of the PAEI runway. For the existing power plant, water vapor is emitted from the stack and the cooling pond, and ice nucleation often occurs almost instantly in winter. The vapor is deposited directly onto solid particles, and the particle size distribution depends on the temperature at the stack and the surface of the pond. The deposition rate D from a vapor-to-solid-phase nucleation increases rapidly with a decreasing absolute temperature T ; deposition also strongly depends on the interfacial energy σ between liquid and vapor, and the saturation ratio S . The derivations of the nucleation rate expression can be found in the work from Götz et al. (1991), Young (1993), and Pruppacher and Klett (1997). D can be derived as

$$D = A \exp[-B \sigma^3 T^3 (\ln S)^{-2}] \quad (4)$$

where A and B are constants (approximately). Evaluation of the constants in various literature sources reveals only small differences in them. For simplicity, we assume herein that all the water vapor generated by the plant is deposited in solid particles.

Particle size decreases with increasing temperatures. For a stack temperature of about 20°C, we assume a typical ice particle size of 10 µm (micrometers). The size of the particles emitted from the surface of the cooling pond at a temperature between 0°C and ~2°C typically can be assumed to range between 10 µm and 13 µm. In our first modeling approach, we treat the ice particles from the 2 sources as equivalent in size at 10 µm. Atmospheric ice concentrations near the surface (at a height of 2 m) are directly compared with visibility measurements.

Test Case and Setup

The WRF/Chem model run times on a supercomputer strongly depend on the number of processors available on the supercomputing system, the size of the geographical domain, grid cell resolution, and the selection of parameterization schemes for the physical and chemical processes to be studied.

The domain of the model test was centered at the Eielson HPP location, and extended horizontally over 100 × 100 grid cells with a cell resolution of 500 meters. Figure 6.4 demonstrates the resultant relatively small model domain with a lateral extent of 50 kilometers. Table 6.3 presents the file header of a WRF output file example, showing the model setup (definition of all variables can be obtained via the WRF community and WRF documentation available at <http://www.wrf-model.org/index.php>). WRF/Chem initial and boundary meteorological conditions were derived from the North America Regional Reanalysis (NARR) archive, which was computed at the National Center for Environmental Prediction (NCEP). In addition, we used chemistry background data from anthropogenic and biogenic sources. The high-resolution domain required short time steps of 2 seconds in order to ensure numerical stability of the model. The model runs were performed at the University of Alaska, Arctic Region Supercomputing Center (ARSC) “Midnight” Sun Opteron cluster (<http://www.arsc.edu/resources/midnight.html>). A 24-hour run of the WRF/Chem model took approximately 40 minutes using 96 processors.

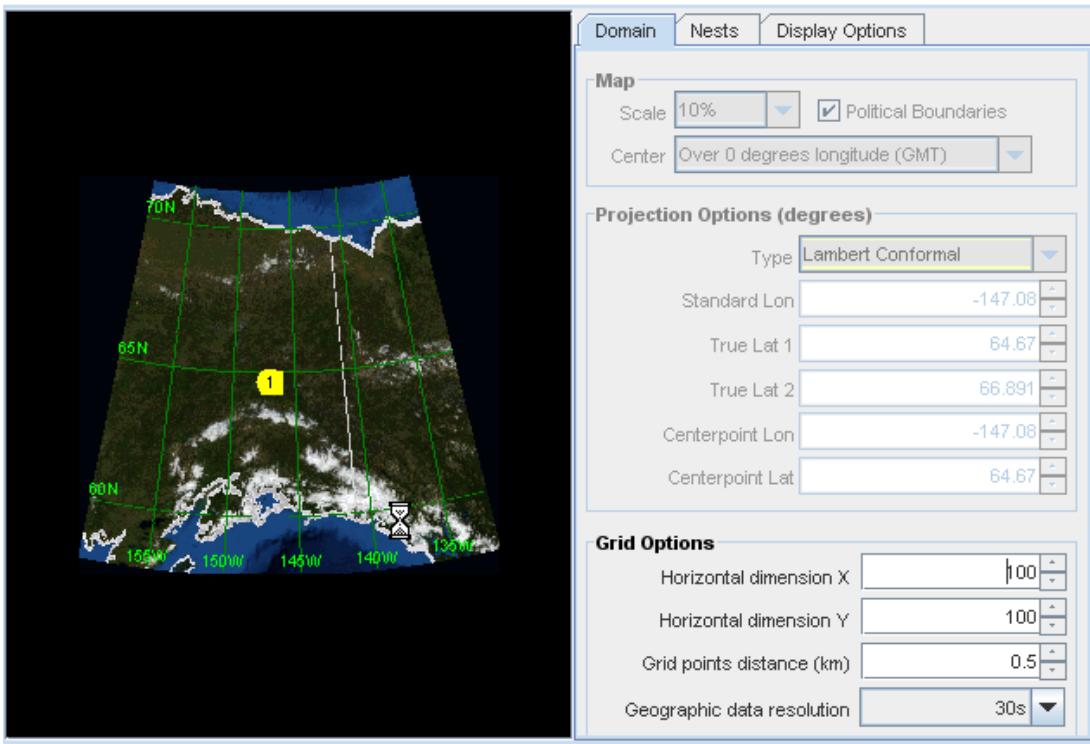


Figure 6.4. The small model domain shown as a yellow point centered at PAEI.

Table 6.3. Domain and model definition variables for the WRF output file from 20 February 2007.

```

TITLE = " OUTPUT FROM WRF V3.1.1 MODEL" ;
:START_DATE = "2007-02-20_00:00:00" ;
:SIMULATION_START_DATE = "2007-02-20_00:00:00" ;
:WEST-EAST_GRID_DIMENSION = 100 ;
:SOUTH-NORTH_GRID_DIMENSION = 100 ;
:BOTTOM-TOP_GRID_DIMENSION = 35 ;
:DX = 500.f ;
:DY = 500.f ;
:GRIDTYPE = "C" ;
:DIFF_OPT = 1 ;
:KM_OPT = 4 ;
:DAMP_OPT = 0 ;
:DAMPCOEF = 0.2f ;
:KHDIF = 0.f ;
:KVDIF = 0.f ;
:MP_PHYSICS = 4 ;
:RA_LW_PHYSICS = 1 ;
:RA_SW_PHYSICS = 2 ;
:SF_SFCLAY_PHYSICS = 1 ;
:SF_SURFACE_PHYSICS = 2 ;
:BL_PBL_PHYSICS = 1 ;
:CU_PHYSICS = 5 ;

```

Table 6.3. *Continued*

```
:SURFACE_INPUT_SOURCE = 1 ;
:SST_UPDATE = 0 ;
:GRID_FDDA = 0 ;
:GFDDA_INTERVAL_M = 0 ;
:GFDDA_END_H = 0 ;
:GRID_SFDDA = 0 ;
:SGFDDA_INTERVAL_M = 0 ;
:SGFDDA_END_H = 0 ;
:SF_URBAN_PHYSICS = 0 ;
:FEEDBACK = 1 ;
:SMOOTH_OPTION = 0 ;
:SWRAD_SCAT = 1.f ;
:W_DAMPING = 0 ;
:MOIST_ADV_OPT = 2 ;
:SCALAR_ADV_OPT = 2 ;
:TKE_ADV_OPT = 1 ;
:DIFF_6TH_OPT = 0 ;
:DIFF_6TH_FACTOR = 0.12f ;
:OBS_NUDGE_OPT = 0 ;
:WEST-EAST_PATCH_START_UNSTAG = 1 ;
:WEST-EAST_PATCH_END_UNSTAG = 99 ;
:WEST-EAST_PATCH_START_STAG = 1 ;
:WEST-EAST_PATCH_END_STAG = 100 ;
:SOUTH-NORTH_PATCH_START_UNSTAG = 1 ;
:SOUTH-NORTH_PATCH_END_UNSTAG = 99 ;
:SOUTH-NORTH_PATCH_START_STAG = 1 ;
:SOUTH-NORTH_PATCH_END_STAG = 100 ;
:BOTTOM-TOP_PATCH_START_UNSTAG = 1 ;
:BOTTOM-TOP_PATCH_END_UNSTAG = 34 ;
:BOTTOM-TOP_PATCH_START_STAG = 1 ;
:BOTTOM-TOP_PATCH_END_STAG = 35 ;
:GRID_ID = 1 ;
:PARENT_ID = 0 ;
:I_PARENT_START = 0 ;
:J_PARENT_START = 0 ;
:PARENT_GRID_RATIO = 1 ;
:DT = 5.f ;
:CEN_LAT = 64.67045f ;
:CEN_LON = -147.0752f ;
:TRUELAT1 = 64.67045f ;
:TRUELAT2 = 64.67045f ;
:MOAD_CEN_LAT = 64.67045f ;
:STAND_LON = -147.0752f ;
:POLE_LAT = 90.f ;
:POLE_LON = 0.f ;
:GMT = 0.f ;
```

Table 6.3. *Continued*

```
:JULYR = 2007 ;
:JULDAY = 51 ;
:MAP_PROJ = 1 ;
:MMINLU = "USGS" ;
:NUM_LAND_CAT = 24 ;
:ISWATER = 16 ;
:ISLAKE = -1 ;
:ISICE = 24 ;
:ISURBAN = 1 ;
:ISOILWATER = 14 ;
```

Our selected reference test case was one week from 20 February 2007; the period started in Interior Alaska with average temperatures of -20°C. The cold anomaly that followed in February and March 2007 resulted from weakening of the circulation pattern in the subpolar Pacific sector and strengthening of the Siberian High, with strong temperature anomalies in Alaska. Large-scale atmospheric circulation patterns and ocean conditions, in general, may influence surface temperature patterns considerably during winter at high latitudes. In particular, the strength and position of the semi-permanent pressure features in the Northern Hemisphere are significant as they relate to air mass advection. A high-pressure system associated with the Beaufort Gyre dominated the central Arctic. During cold seasons, variability in the strength and position of these semi-permanent features translates into large temperature variability. Cold anomalies have caused periods of ice fog and reduced visibility in Interior Alaska, even in late winter and early spring. The period was selected due to widely varying cold temperatures with ice fog and related rapidly changing visibility observations (compare Figure 6.3). The METAR observations repeatedly contain references to the HPP plume of ice fog (PWR PLNT PLME). An example observation reads as follows:

SPECI PAEI 211945Z 01001KT 1 1/2SM BR SCT003 M35/M35 A3023 RMK PWR PLNT PLME SCT003.

Model Result and Visibility

The WRF/Chem model was successfully initialized with power plant water vapor emissions. We assumed that water vapor was deposited in the atmosphere in the form of one bin size of ice particles, with a typical diameter of 10 µm. Concentrations of fine particulate matter with a diameter of 10 µm were analyzed from WRF/Chem output at the Eielson Air Force Base runway 32 localizer at 64°41'22"N and 147°7'19"W for the test period beginning 20 February 2007. The concentration values were compared with visibility observations conducted by PAEI weather station operations. Modeled wind and

temperatures compared very well with the respective observed values for the test period. In general, the dispersion of pollutants (with sources at or near the surface) strongly depends on vertical stability within the boundary layer. A realistic presentation of temperature inversions has been a challenge so far in modeling air quality in arctic and subarctic settings. The WRF/Chem initialization (with NARR reanalysis data) used herein resulted in strong temperature inversions throughout the test period, hampering vertical dispersion of water vapor above the boundary layer. Figure 6.5 shows a series of PM₁₀ (ice) concentration maps from 21 February to 23 February. The model was initialized with HPP plant emissions of 30 tons/hour; we assumed an invariant emission rate and 100% water vapor deposition in the atmosphere. The different dispersion maps in Figure 6.5 demonstrate the observed variability of wind direction. The winds from the east are especially important for ice fog formation, since the ice fog disperses along the PAEI runway, causing reduced visibility. The dynamics of ice dispersion show a clear daily cycle with easterly winds in the morning hours, causing daily peak concentrations of ice fog. These peaks coincide well with measured reduced visibility (Figure 6.6). We derived a correlation of $R = -0.32$ between visibility measurements and the PM₁₀ concentration for the period of 20 February to 27 February 2007. Reduced correlation was found due to certain visibility-measurement thresholds and, of course, due to first-order model assumptions.

Assessment of CO₂ Sequestration Options and Other Environmental Impacts
Related to the Proposed Coal-to-Liquids Plant at Eielson Air Force Base

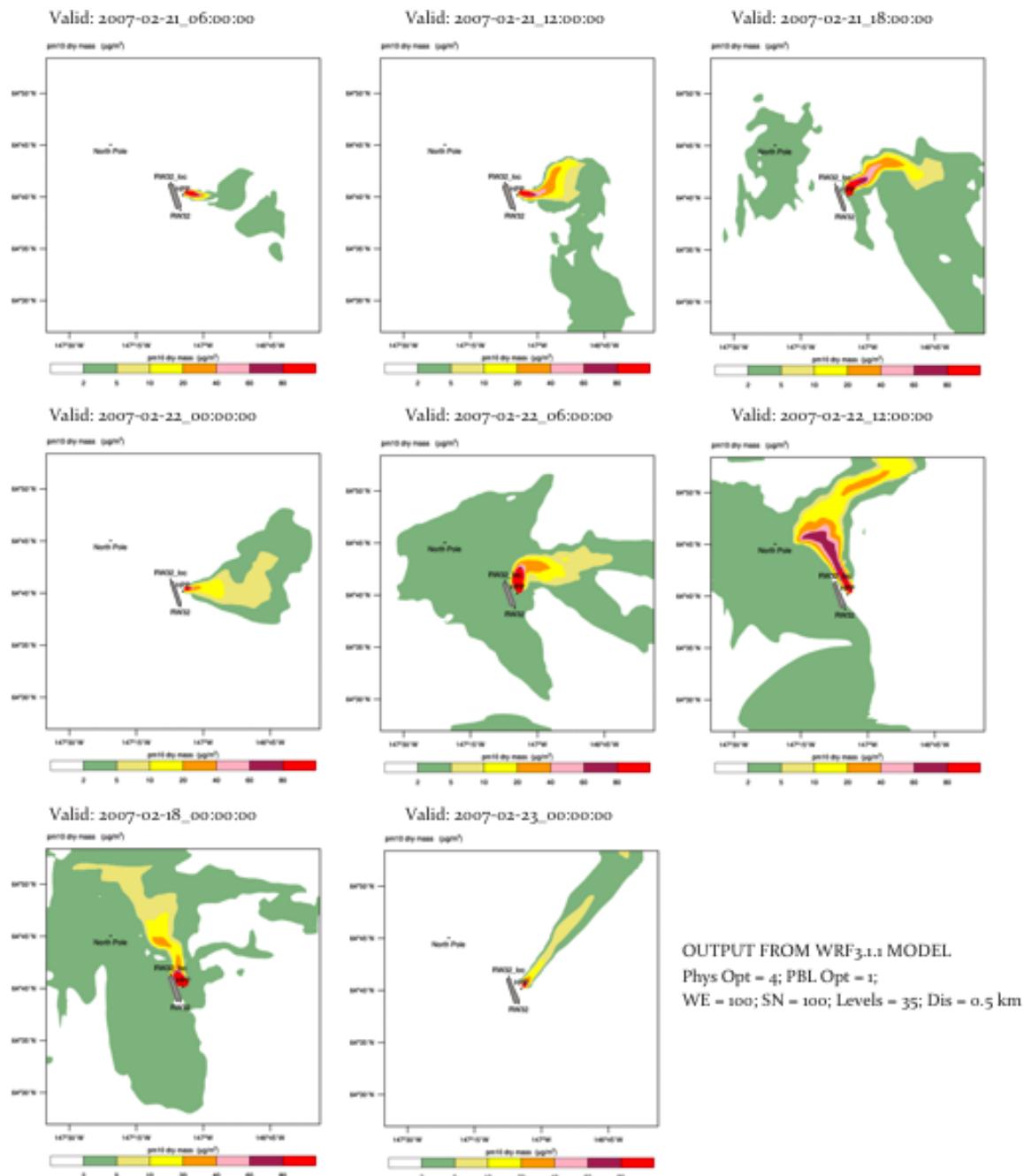


Figure 6.5. PM10 ice particle dispersion near the surface in 6-hour intervals from 2007-02-21_06:00 to 2007-02-23_00:00. The locations of the HPP (in the center of the model domain), the PAEI runway, and the runway 32 localizer are marked.

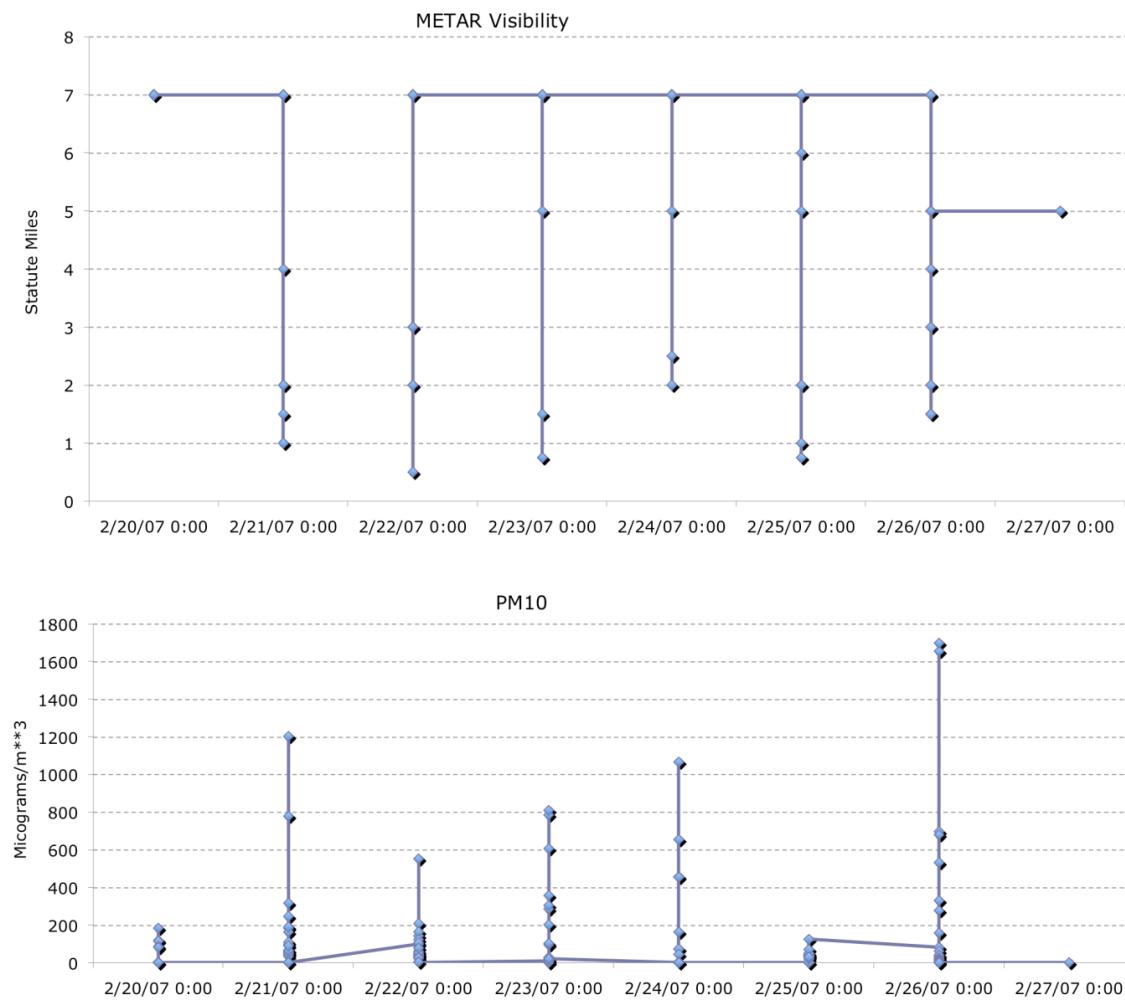


Figure 6.6. Observed visibility at PAEI (top) in comparison to PM10 ice particle concentration (bottom).

Summary and Conclusions

Water vapor emissions were estimated for the Eielson HPP. Vapor emission sources from burning of fuel and transfer of excess heat in the cooling pond near the HPP were identified. Estimates of emission rates served as input for the model. We successfully configured the WRF/Chem model with water vapor emissions, assuming that 100% of the water vapor is deposited in the atmosphere during cold winter periods. A further assumption included the size of the ice particles. A uniform ice particle size of 10 µm was used. A WRF/Chem model domain of 50 × 50 kilometers with a 500-meter grid cell size was centered on the HPP. We selected the last week of February 2007 as the test period. Meteorological observations during this period revealed a strong, cold anomaly and significant periods of ice fog along the PAEI runway.

Ice fog dispersion from the HPP during the test period clearly shows a daily cycle, with peak concentrations during the morning hours due to slight outflow of air from the east. The PAEI meteorologists confirmed that such a cycle occurs often during the winter. The ice concentrations correlate well with measurements of reduced visibility. However, only a little water vapor from the HPP is needed to cause saturation at temperatures of below -40°C. Saturation and high concentration of ice in the atmosphere prevailed throughout the test period above the HPP source. Further studies are needed to find thresholds of ice fog formation at less-cold temperatures. These thresholds will allow the quantification of the effects of increased water vapor emissions on ice fog. Increased water vapor emissions may result because of the construction of a CTL plant. Within the scope of this study, we compared only particle concentrations with visibility measurements due to the very simplified treatment of ice in the model. Ice deposition from water vapor occurs at different temperatures above the water surface of the pond and the slag of the HPP. These different temperatures result in a variety of ice particles with different sizes and optical characteristics. Aerosol schemes describing aqueous reactions and particle size modifications need to be considered in WRF/Chem. A deposition model has to be coupled to the dispersion model in order to translate the ice particle concentrations to visibility. However, the simplified approach clearly identifies the HPP as a source of ice fog formation. A coupling of a deposition model and a model describing the optical properties with the WRF/Chem model will allow more accurate results and additional variables (such as visibility).

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CONCLUSIONS

Construction of a coal-to-liquids plant on Eielson Air Force Base would have several ancillary impacts, including CO₂, water vapor, and trace element emissions. This report summarizes the available options for mitigating these impacts, based on public literature.

After considering all the possible “conventional” geologic sequestration options, the most viable option of sequestering CO₂ generated by the proposed plant is to use it in enhanced oil recovery in North Slope petroleum fields. While this is a demonstrated technology, it would require construction of a 500-mile pipeline to ship the CO₂ from Fairbanks to the North Slope. Alternatively, closer to Fairbanks, CO₂ could be sequestered in deep coal seams near the Healy coalfields. While this option would require a significantly shorter pipeline (115 miles), the distribution of the coal seams at depth is not well understood and the sequestration technology is still being developed and tested. A third option, that of sequestering CO₂ in the Fairbanks area by reacting it with mafic rock either at depth or at the surface, is the most speculative of the options but has the fewest CO₂ transportation issues. There are no local depleted oil or gas fields in the Fairbanks area that could be used for geologic storage of CO₂. Other potential CO₂ sinks, such as deep saline aquifers associated with good permeability seals, have not been identified in Interior Alaska, and may not exist here. Injecting CO₂ into methane hydrate structures on the North Slope to recover natural gas has been demonstrated in the laboratory, but large-scale field demonstrations have not been completed.

Other geologic sequestration methods that have been proposed do not appear practical in Alaska at this time, including deep ocean storage, storage beneath permafrost formations, and ejection of CO₂ from the atmosphere along open magnetic field lines (see Chapter 3 for more information on these and other proposed techniques).

Carbon dioxide emission reduction by using natural, unmanaged biomass stands as feedstock does not appear practical. Local production of biomass, as determined in unmanaged willow stands, measures from 464 lb/acre to 1,047 lb/acre per year. The ½-ton/acre harvest in Alaska is considerably lower than the 4–5 ton/acre production rates in other parts of the world. Using biomass feedstock to mitigate the released CO₂ would require harvesting willows or local trees from approximately one million acres. Land suitable for production on this scale has not been identified, nor have harvesting, transporting, or drying costs been estimated. However, with more research into willow growth rates under Alaskan conditions, there is potential for an increased biomass production from a managed stand.

Other proposed biomass sequestration options, such as production of algae, require water, warmth, and sunlight, all of which are in short supply during the long Alaskan winters and, hence, do not appear practical in Fairbanks. Biological sequestration methods, such

as the use of fertilizers in ocean waters, have been suggested, but these are not locally practical.

Pollutants directly related to the proposed feedstock coal—Healy coal—were found to be minimal, with very low amounts of sulfur (especially pyritic sulfur), metallic trace elements, and nitrogen. Major gaseous emissions from a coal-to-liquids (CTL) plant would consist of SO_x, NO_x, particulate matter, CO, and CO₂. Gaseous emissions from the CTL plant will likely contain some amount of trace elements. Given the cold climate of Alaska, particularly Fairbanks, water vapor emissions may be critical because of their impact on visibility. The major solid effluents would be dry ash or slag, and fly ash. Ash disposal can be a problem especially if it is leachable. Slag is much easier to handle because it is inert and volumetrically smaller than dry ash. Water will be the major liquid effluent. Some of these pollutants could be addressed by ultra cleaning the coal and/or using a different gasification process than the one proposed.

A major operational concern is the effect of water vapor emission by the proposed CTL plant on visibility, especially during winter when ice fog conditions are common. As currently configured, the CTL plant design releases several hundred tons per hour of water vapor into the atmosphere, which will form ice fog at temperatures of -20°F and below. A computer model was successfully constructed that clearly showed a daily cycle of ice fog development related to the current heat and power plant. Eielson meteorologists confirmed that such a cycle often occurs during the winter, suggesting that the computer model could provide an important predictive tool for evaluating the effect of the proposed CTL emissions on ice fog formation.

There is significant uncertainty on the likely cost of carbon capture and sequestration from a CTL plant sited on Eielson Air Force Base, because there are few operational facilities using applicable technologies that can be used as cost comparisons. Two different modeling approaches were used to estimate costs for CO₂ capture and sequestration. One method was a cost-per-ton analysis using costs from the economic literature. The second method used capital and operating costs of CO₂ capture, transportation, and sequestration specific to the Eielson CTL facility. In general, the capital-cost method produced lower costs per ton and per gallon. Costs per ton of CO₂ sequestered ranged from \$9.47 for easy-to-capture CO₂ to \$99.07 per ton for the hard-to-capture CO₂ stream sequestered at Usibelli Coal Mine. Costs per gallon ranged from \$0.09 per gallon for easy-to-capture CO₂ to \$1.81 per gallon for CO₂ pipelined to the North Slope. On a total annual-cost basis, costs ranged from approximately \$48 million per year for easy-to-capture CO₂ sequestered at Usibelli, to \$909 million per year for full-capture CO₂ sequestered on the North Slope.

Appendix A

Sensitivity Analysis and Economic Modeling Results for an Interior Alaska Coal-to-Liquids Facility

Hatch Report Case 1 Scenario Summary

Project	Streams	Pipeline Path
Case 1	All Captured	Eielson to Usibelli
Captial based	\$/ton	\$ 19.59
	\$/year	\$ 115,051,300
Per ton	\$/ton	\$ 75.20
	\$/year	\$ 441,717,619
Case 1	Easy to Capture	Eielson to Usibelli
Captial based	\$/ton	\$ 13.11
	\$/year	\$ 63,210,160
Per ton	\$/ton	\$ 73.07
	\$/year	\$ 352,320,943
Case 1	Hard to Capture	Eielson to Usibelli
Captial based	\$/ton	\$ 82.64
	\$/year	\$ 86,912,940
Per ton	\$/ton	\$ 99.07
	\$/year	\$ 104,190,263
Case 1	All Captured	Usibelli to Usibelli
Captial based	\$/ton	\$ 15.73
	\$/year	\$ 92,367,800
Per ton	\$/ton	\$ 71.34
	\$/year	\$ 419,034,118
Case 1	All Captured	Usibelli to North Slope
Captial based	\$/ton	\$ 31.38
	\$/year	\$ 184,307,491
Per ton	\$/ton	\$ 87.00
	\$/year	\$ 510,973,809
Case 1	All Captured	Eielson to North Slope
Captial based	\$/ton	\$ 26.85
	\$/year	\$ 157,679,034
Per ton	\$/ton	\$ 82.46
	\$/year	\$ 484,345,352

Project	Streams	Pipeline Path
Case 1	All Captured	Eielson to Usibelli
Case 1 All Captured		

Capital Based Method

Operating Costs

CO ₂ Captured	ton/year	\$	5,873,545
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	29,367,724.80
Electric Cost	kWh/year	\$	253,058,880
Electric Cost	\$/year	\$	50,611,776
Electric Cost	\$/ton	\$	8.62

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	4.53
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.44

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	19.59
Cost of CCS	\$/year	\$	115,051,300

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO ₂ Captured	ton/year	\$	5,873,545
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Cost to Capture	\$/year	\$	426,924,031
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Cost to Capture	\$/ton	\$	73
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Pipline Costs	\$ per project	\$	208,500,000
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Pipline Costs	annual payment	\$	14,793,587
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Pipline Costs	\$/ton	\$	2.52
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
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Revenue from Carbon Sales	\$/year	\$	-
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Total

Cost of CCS	\$/ton	\$	75.20
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Cost of CCS	\$/year	\$	441,717,619
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Project	Streams	Pipeline Path
Case 1	Easy to Capture	Eielson to Usibelli
Case 1 Easy to Capture		
Capital Based Method		

Operating Costs

CO2 Captured	ton/year		4,821,819
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	24,109,096.80
Electric Cost	kWh/year		20,146,316
Electric Cost	\$/year	\$	4,029,263
Electric Cost	\$/ton	\$	0.84

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	5.52
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.75

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	13.11
Cost of CCS	\$/year	\$	63,210,160

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO2 Captured	ton/year		4,821,819
Cost to Capture	\$/year	\$	337,527,355
Cost to Capture	\$/ton	\$	70
Pipline Costs	\$ per project	\$	208,500,000
Pipline Costs	annual payment	\$	14,793,587
Pipline Costs	\$/ton	\$	3.07

Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	73.07
Cost of CCS	\$/year	\$	352,320,943

Project	Streams	Pipeline Path
Case 1	Hard to Capture	Eielson to Usibelli
Case 1 Hard to Capture		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		1,051,726
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	5,258,628.00
Electric Cost	kWh/year		232,912,564
Electric Cost	\$/year	\$	46,582,513
Electric Cost	\$/ton	\$	44.29

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	25.32
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	8.03

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	82.64
Cost of CCS	\$/year	\$	86,912,940

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO₂ Captured

CO ₂ Captured	ton/year		1,051,726
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Cost to Capture

Cost to Capture	\$/year	\$	89,396,676
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Cost to Capture

Cost to Capture	\$/ton	\$	85
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Pipline Costs

Pipline Costs	\$ per project	\$	208,500,000
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Pipline Costs

Pipline Costs	annual payment	\$	14,793,587
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Pipline Costs	\$/ton	\$	14.07
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
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Revenue from Carbon Sales	\$/year	\$	-
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Total

Cost of CCS	\$/ton	\$	99.07
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Cost of CCS	\$/year	\$	104,190,263
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Project	Streams	Pipeline Path
Case 1	All Captured	Usibelli to Usibelli
Case 1 All Captured		
Capital Based Method		

Operating Costs

CO2 Captured	ton/year		5,873,545
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	29,367,724.80
Electric Cost	kWh/year		253,058,880
Electric Cost	\$/year	\$	50,611,776
Electric Cost	\$/ton	\$	8.62

Capital Costs

Pipline Costs	\$ per project	\$	55,600,000
Pipline Costs	annual payment	\$	3,944,957
Pipline Costs	\$/ton	\$	0.67
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.44

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	15.73
Cost of CCS	\$/year	\$	92,367,800

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO2 Captured	ton/year		5,873,545
Cost to Capture	\$/year	\$	426,924,031
Cost to Capture	\$/ton	\$	73
Pipline Costs	\$ per project	\$	(111,200,000)
Pipline Costs	annual payment	\$	(7,889,913)
Pipline Costs	\$/ton	\$	(1.34)

Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	71.34
Cost of CCS	\$/year	\$	419,034,118

Project	Streams	Pipeline Path
Case 1	All Captured	Usibelli to North Slope
Case 1 All Captured		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		5,873,545
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	29,367,724.80
Electric Cost	kWh/year		253,058,880
Electric Cost	\$/year	\$	50,611,776
Electric Cost	\$/ton	\$	8.62

Capital Costs

Pipline Costs	\$ per project	\$	1,765,300,000
Pipline Costs	annual payment	\$	125,252,373
Pipline Costs	\$/ton	\$	21.32
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.44

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	5.00
Revenue from Carbon Sales	\$/year	\$	29,367,725

Total

Cost of CCS	\$/ton	\$	31.38
Cost of CCS	\$/year	\$	184,307,491

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO₂ Captured

ton/year

5,873,545

Cost to Capture

\$/year

426,924,031

Cost to Capture

\$/ton

73

Pipline Costs

\$ per project

1,598,500,000

Pipline Costs

annual payment

113,417,503

Pipline Costs

\$/ton

19.31

Carbon Sales

Price of Carbon for EOR	\$/ton	\$	5.00
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Revenue from Carbon Sales	\$/year	\$	29,367,725
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Total

Cost of CCS	\$/ton	\$	87.00
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Cost of CCS	\$/year	\$	510,973,809
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Project	Streams	Pipeline Path
Case 1	All Captured	Eielson to North Slope
Case 1 All Captured		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		5,873,545
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	29,367,724.80
Electric Cost	kWh/year		253,058,880
Electric Cost	\$/year	\$	50,611,776
Electric Cost	\$/ton	\$	8.62

Capital Costs

Pipline Costs	\$ per project	\$	1,390,000,000
Pipline Costs	annual payment	\$	98,623,916
Pipline Costs	\$/ton	\$	16.79
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.44

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	5.00
Revenue from Carbon Sales	\$/year	\$	29,367,725

Total

Cost of CCS	\$/ton	\$	26.85
Cost of CCS	\$/year	\$	157,679,034

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO ₂ Captured	ton/year		5,873,545
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Cost to Capture	\$/year	\$	426,924,031
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Cost to Capture	\$/ton	\$	73
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Pipline Costs	\$ per project	\$	1,223,200,000
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Pipline Costs	annual payment	\$	86,789,046
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Pipline Costs	\$/ton	\$	14.78
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	5.00
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Revenue from Carbon Sales	\$/year	\$	29,367,725
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Total

Cost of CCS	\$/ton	\$	82.46
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Cost of CCS	\$/year	\$	484,345,352
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Hatch Report Case 2 Scenario Summary

Project	Streams	Pipeline Path
Case 2	All Captured	Eielson to Usibelli
Captial based	\$/ton	\$ 16.59
	\$/year	\$ 194,869,617
Per ton	\$/ton	\$ 73.95
	\$/year	\$ 868,698,064
Case 2	Easy to Capture	Eielson to Usibelli
Captial based	\$/ton	\$ 9.47
	\$/year	\$ 91,353,223
Per ton	\$/ton	\$ 71.53
	\$/year	\$ 689,904,712
Case 2	Hard to Capture	Eielson to Usibelli
Captial based	\$/ton	\$ 65.89
	\$/year	\$ 138,592,224
Per ton	\$/ton	\$ 92.03
	\$/year	\$ 193,586,939
Case 2	All Captured	Usibelli to Usibelli
Captial based	\$/ton	\$ 14.66
	\$/year	\$ 172,186,117
Per ton	\$/ton	\$ 72.02
	\$/year	\$ 846,014,564
Case 2	All Captured	Usibelli to North Slope
Captial based	\$/ton	\$ 19.98
	\$/year	\$ 234,758,083
Per ton	\$/ton	\$ 77.35
	\$/year	\$ 908,586,530
Case 2	All Captured	Eielson to North Slope
Captial based	\$/ton	\$ 17.72
	\$/year	\$ 208,129,626
Per ton	\$/ton	\$ 75.08
	\$/year	\$ 881,958,073

Project	Streams	Pipeline Path
Case 2	All Captured	Eielson to Usibelli
Case 2 All Captured		

Capital Based Method

Operating Costs

CO ₂ Captured	ton/year		11,747,090
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	58,735,449.60
Electric Cost	kWh/year		505,311,840
Electric Cost	\$/year	\$	101,062,368
Electric Cost	\$/ton	\$	8.60

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	2.27
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	0.72

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	16.59
Cost of CCS	\$/year	\$	194,869,617

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO ₂ Captured	ton/year		11,747,090
Cost to Capture	\$/year	\$	853,904,477
Cost to Capture	\$/ton	\$	73
Pipline Costs	\$ per project	\$	208,500,000
Pipline Costs	annual payment	\$	14,793,587
Pipline Costs	\$/ton	\$	1.26

Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	73.95
Cost of CCS	\$/year	\$	868,698,064

Project	Streams	Pipeline Path
Case 2	Easy to Capture	Eielson to Usibelli
Case 2 Easy to Capture		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		9,644,445
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	48,222,223.20
Electric Cost	kWh/year		40,296,000
Electric Cost	\$/year	\$	8,059,200
Electric Cost	\$/ton	\$	0.84

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	2.76
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	0.88

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	9.47
Cost of CCS	\$/year	\$	91,353,223

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO₂ Captured

CO ₂ Captured	ton/year		9,644,445
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Cost to Capture

Cost to Capture	\$/year	\$	675,111,125
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Cost to Capture

Cost to Capture	\$/ton	\$	70
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Pipline Costs

Pipline Costs	\$ per project	\$	208,500,000
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Pipline Costs

Pipline Costs	annual payment	\$	14,793,587
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Pipline Costs	\$/ton	\$	1.53
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
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Revenue from Carbon Sales	\$/year	\$	-
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Total

Cost of CCS	\$/ton	\$	71.53
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Cost of CCS	\$/year	\$	689,904,712
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Project	Streams	Pipeline Path
Case 2	Hard to Capture	Eielson to Usibelli
Case 2 Hard to Capture		
Capital Based Method		

Operating Costs

CO2 Captured	ton/year		2,103,451
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	10,517,256.00
Electric Cost	kWh/year		465,015,840
Electric Cost	\$/year	\$	93,003,168
Electric Cost	\$/ton	\$	44.21

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	12.66
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	4.01

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	65.89
Cost of CCS	\$/year	\$	138,592,224

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO2 Captured	ton/year		2,103,451
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Cost to Capture	\$/year	\$	178,793,352
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Cost to Capture	\$/ton	\$	85
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Pipline Costs	\$ per project	\$	208,500,000
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Pipline Costs	annual payment	\$	14,793,587
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Pipline Costs	\$/ton	\$	7.03
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
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Revenue from Carbon Sales	\$/year	\$	-
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Total

Cost of CCS	\$/ton	\$	92.03
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Cost of CCS	\$/year	\$	193,586,939
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Project	Streams	Pipeline Path
Case 2	All Captured	Usibelli to Usibelli
Case 2 All Captured		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		11,747,090
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	58,735,449.60
Electric Cost	kWh/year		505,311,840
Electric Cost	\$/year	\$	101,062,368
Electric Cost	\$/ton	\$	8.60

Capital Costs

Pipline Costs	\$ per project	\$	55,600,000
Pipline Costs	annual payment	\$	3,944,957
Pipline Costs	\$/ton	\$	0.34
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	0.72

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	14.66
Cost of CCS	\$/year	\$	172,186,117

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO₂ Captured

CO ₂ Captured	ton/year		11,747,090
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Cost to Capture

Cost to Capture	\$/year	\$	853,904,477
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Cost to Capture

Cost to Capture	\$/ton	\$	73
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Pipline Costs

Pipline Costs	\$ per project	\$	(111,200,000)
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Pipline Costs

Pipline Costs	annual payment	\$	(7,889,913)
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Pipline Costs

Pipline Costs	\$/ton	\$	(0.67)
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
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Revenue from Carbon Sales	\$/year	\$	-
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Total

Cost of CCS	\$/ton	\$	72.02
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Cost of CCS	\$/year	\$	846,014,564
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Project	Streams	Pipeline Path
Case 2	All Captured	Usibelli to North Slope
Case 2 All Captured		
Capital Based Method		

Operating Costs

CO2 Captured	ton/year		11,747,090
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	58,735,449.60
Electric Cost	kWh/year		505,311,840
Electric Cost	\$/year	\$	101,062,368
Electric Cost	\$/ton	\$	8.60

Capital Costs

Pipline Costs	\$ per project	\$	1,765,300,000
Pipline Costs	annual payment	\$	125,252,373
Pipline Costs	\$/ton	\$	10.66
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	0.72

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	5.00
Revenue from Carbon Sales	\$/year	\$	58,735,450

Total

Cost of CCS	\$/ton	\$	19.98
Cost of CCS	\$/year	\$	234,758,083

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO2 Captured	ton/year		11,747,090
Cost to Capture	\$/year	\$	853,904,477
Cost to Capture	\$/ton	\$	73
Pipline Costs	\$ per project	\$	1,598,500,000
Pipline Costs	annual payment	\$	113,417,503
Pipline Costs	\$/ton	\$	9.65

Carbon Sales

Price of Carbon for EOR	\$/ton	\$	5.00
Revenue from Carbon Sales	\$/year	\$	58,735,450

Total

Cost of CCS	\$/ton	\$	77.35
Cost of CCS	\$/year	\$	908,586,530

Project	Streams	Pipeline Path
Case 2	All Captured	Eielson to North Slope
Case 2 All Captured		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		11,747,090
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	58,735,449.60
Electric Cost	kWh/year		505,311,840
Electric Cost	\$/year	\$	101,062,368
Electric Cost	\$/ton	\$	8.60

Capital Costs

Pipline Costs	\$ per project	\$	1,390,000,000
Pipline Costs	annual payment	\$	98,623,916
Pipline Costs	\$/ton	\$	8.40
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	0.72

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	5.00
Revenue from Carbon Sales	\$/year	\$	58,735,450

Total

Cost of CCS	\$/ton	\$	17.72
Cost of CCS	\$/year	\$	208,129,626

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO₂ Captured

CO ₂ Captured	ton/year		11,747,090
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Cost to Capture

Cost to Capture	\$/year	\$	853,904,477
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Cost to Capture

Cost to Capture	\$/ton	\$	73
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Pipline Costs

Pipline Costs	\$ per project	\$	1,223,200,000
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Pipline Costs

Pipline Costs	annual payment	\$	86,789,046
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Pipline Costs

Pipline Costs	\$/ton	\$	7.39
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	5.00
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Revenue from Carbon Sales	\$/year	\$	58,735,450
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Total

Cost of CCS	\$/ton	\$	75.08
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Cost of CCS	\$/year	\$	881,958,073
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Hatch Report Case 3 Scenario Summary

Project	Streams	Pipeline Path
Case 3	All Captured	Eielson to Usibelli
Captial based	\$/ton	\$ 40.71
	\$/year	\$ 238,252,291
Per ton	\$/ton	\$ 81.80
	\$/year	\$ 478,713,376
Case 3	Easy to Capture	Eielson to Usibelli
Captial based	\$/ton	\$ 21.48
	\$/year	\$ 48,150,987
Per ton	\$/ton	\$ 76.60
	\$/year	\$ 171,682,034
Case 3	Hard to Capture	Eielson to Usibelli
Captial based	\$/ton	\$ 62.34
	\$/year	\$ 225,177,133
Per ton	\$/ton	\$ 89.10
	\$/year	\$ 321,824,930
Case 3	All Captured	Usibelli to Usibelli
Captial based	\$/ton	\$ 36.83
	\$/year	\$ 215,568,790
Per ton	\$/ton	\$ 77.92
	\$/year	\$ 456,029,876
Case 3	All Captured	Usibelli to North Slope
Captial based	\$/ton	\$ 52.56
	\$/year	\$ 307,613,251
Per ton	\$/ton	\$ 93.65
	\$/year	\$ 548,074,337
Case 3	All Captured	Eielson to North Slope
Captial based	\$/ton	\$ 48.01
	\$/year	\$ 280,984,794
Per ton	\$/ton	\$ 89.10
	\$/year	\$ 521,445,879

Project	Streams	Pipeline Path
Case 3	All Captured	Eielson to Usibelli
Case 3 All Captured		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		5,852,591
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	29,262,955.20
Electric Cost	kWh/year		869,587,680
Electric Cost	\$/year	\$	173,917,536
Electric Cost	\$/ton	\$	29.72

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	4.55
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.44

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	40.71
Cost of CCS	\$/year	\$	238,252,291

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO₂ Captured

CO ₂ Captured	ton/year		5,852,591
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Cost to Capture

Cost to Capture	\$/year	\$	463,919,789
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Cost to Capture

Cost to Capture	\$/ton	\$	79
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Pipline Costs

Pipline Costs	\$ per project	\$	208,500,000
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Pipline Costs

Pipline Costs	annual payment	\$	14,793,587
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Pipline Costs

Pipline Costs	\$/ton	\$	2.53
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
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Revenue from Carbon Sales	\$/year	\$	-
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Total

Cost of CCS	\$/ton	\$	81.80
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Cost of CCS	\$/year	\$	478,713,376
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Project	Streams	Pipeline Path
Case 3	Easy to Capture	Eielson to Usibelli
Case 3 Easy to Capture		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		2,241,264
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	11,206,317.60
Electric Cost	kWh/year		9,364,350
Electric Cost	\$/year	\$	1,872,870
Electric Cost	\$/ton	\$	0.84

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	11.88
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	3.77

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	21.48
Cost of CCS	\$/year	\$	48,150,987

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO ₂ Captured	ton/year		2,241,264
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Cost to Capture	\$/year	\$	156,888,446
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Cost to Capture	\$/ton	\$	70
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Pipline Costs	\$ per project	\$	208,500,000
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Pipline Costs	annual payment	\$	14,793,587
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Pipline Costs	\$/ton	\$	6.60
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
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Revenue from Carbon Sales	\$/year	\$	-
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Total

Cost of CCS	\$/ton	\$	76.60
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Cost of CCS	\$/year	\$	171,682,034
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Project	Streams	Pipeline Path
Case 3	Hard to Capture	Eielson to Usibelli
Case 3 Hard to Capture		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		3,612,133
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	18,060,667.20
Electric Cost	kWh/year		860,223,330
Electric Cost	\$/year	\$	172,044,666
Electric Cost	\$/ton	\$	47.63

Capital Costs

Pipline Costs	\$ per project	\$	375,300,000
Pipline Costs	annual payment	\$	26,628,457
Pipline Costs	\$/ton	\$	7.37
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	2.34

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	62.34
Cost of CCS	\$/year	\$	225,177,133

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO₂ Captured

CO ₂ Captured	ton/year		3,612,133
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Cost to Capture

Cost to Capture	\$/year	\$	307,031,342
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Cost to Capture

Cost to Capture	\$/ton	\$	85
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Pipline Costs

Pipline Costs	\$ per project	\$	208,500,000
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Pipline Costs

Pipline Costs	annual payment	\$	14,793,587
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Pipline Costs

Pipline Costs	\$/ton	\$	4.10
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Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
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Revenue from Carbon Sales	\$/year	\$	-
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Total

Cost of CCS	\$/ton	\$	89.10
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Cost of CCS	\$/year	\$	321,824,930
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Project	Streams	Pipeline Path
Case 3	All Captured	Usibelli to Usibelli
Case 3 All Captured		
Capital Based Method		

Operating Costs

CO2 Captured	ton/year		5,852,591
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	29,262,955.20
Electric Cost	kWh/year		869,587,680
Electric Cost	\$/year	\$	173,917,536
Electric Cost	\$/ton	\$	29.72

Capital Costs

Pipline Costs	\$ per project	\$	55,600,000
Pipline Costs	annual payment	\$	3,944,957
Pipline Costs	\$/ton	\$	0.67
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.44

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	36.83
Cost of CCS	\$/year	\$	215,568,790

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO2 Captured	ton/year		5,852,591
Cost to Capture	\$/year	\$	463,919,789
Cost to Capture	\$/ton	\$	79
Pipline Costs	\$ per project	\$	(111,200,000)
Pipline Costs	annual payment	\$	(7,889,913)
Pipline Costs	\$/ton	\$	(1.35)

Carbon Sales

Price of Carbon for EOR	\$/ton	\$	-
Revenue from Carbon Sales	\$/year	\$	-

Total

Cost of CCS	\$/ton	\$	77.92
Cost of CCS	\$/year	\$	456,029,876

Project	Streams	Pipeline Path
Case 3	All Captured	Usibelli to North Slope
Case 3 All Captured		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		5,852,591
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	29,262,955.20
Electric Cost	kWh/year		869,587,680
Electric Cost	\$/year	\$	173,917,536
Electric Cost	\$/ton	\$	29.72

Capital Costs

Pipline Costs	\$ per project	\$	1,765,300,000
Pipline Costs	annual payment	\$	125,252,373
Pipline Costs	\$/ton	\$	21.40
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.44

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	5.00
Revenue from Carbon Sales	\$/year	\$	29,262,955

Total

Cost of CCS	\$/ton	\$	52.56
Cost of CCS	\$/year	\$	307,613,251

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO₂ Captured

ton/year

5,852,591

Cost to Capture

\$/year

463,919,789

Cost to Capture

\$/ton

79

Pipline Costs

\$ per project

1,598,500,000

Pipline Costs

annual payment

113,417,503

Pipline Costs

\$/ton

19.38

Carbon Sales

Price of Carbon for EOR	\$/ton	\$	5.00
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Revenue from Carbon Sales	\$/year	\$	29,262,955
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Total

Cost of CCS	\$/ton	\$	93.65
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Cost of CCS	\$/year	\$	548,074,337
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Project	Streams	Pipeline Path
Case 3	All Captured	Eielson to North Slope
Case 3 All Captured		
Capital Based Method		

Operating Costs

CO ₂ Captured	ton/year		5,852,591
Cost to Capture	\$/ton	\$	5.00
Cost to Capture	\$/year	\$	29,262,955.20
Electric Cost	kWh/year		869,587,680
Electric Cost	\$/year	\$	173,917,536
Electric Cost	\$/ton	\$	29.72

Capital Costs

Pipline Costs	\$ per project	\$	1,390,000,000
Pipline Costs	annual payment	\$	98,623,916
Pipline Costs	\$/ton	\$	16.85
Compressor and Injection Well	\$ per project	\$	119,000,000
Compressor and Injection Well	annual payment	\$	8,443,342
Compressor and Injection Well	\$/ton	\$	1.44

Carbon Sales

Value of Carbon for EOR	\$/ton	\$	5.00
Revenue from Carbon Sales	\$/year	\$	29,262,955

Total

Cost of CCS	\$/ton	\$	48.01
Cost of CCS	\$/year	\$	280,984,794

Per Ton Method

Easy to Capture

Early commercial	\$/ton	\$	70.00
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Hard to Capture

Demonstration low	\$/ton	\$	85.00
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CO ₂ Captured	ton/year		5,852,591
Cost to Capture	\$/year	\$	463,919,789
Cost to Capture	\$/ton	\$	79
Pipline Costs	\$ per project	\$	1,223,200,000
Pipline Costs	annual payment	\$	86,789,046
Pipline Costs	\$/ton	\$	14.83

Carbon Sales

Price of Carbon for EOR	\$/ton	\$	5.00
Revenue from Carbon Sales	\$/year	\$	29,262,955

Total

Cost of CCS	\$/ton	\$	89.10
Cost of CCS	\$/year	\$	521,445,879



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