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A Report for NWPCC

CO2 Capture and Storage

An Overview of Information Available for the Western U.S.

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1 An Introduction to CO_2 Capture and Storage

CO_2 capture and storage (CCS) is the term given to efforts to capture the CO_2 from high-emitting stationary sources of the gas (e.g. power plants) and store it such that it is permanently sequestered. This report summarizes the status of CCS and the NWPCC's request to explore information regarding the potential of CCS in the states currently associated with the Western Climate Initiative (WCI) EcoSecurities Consulting Ltd. (ECL) focuses on these states given the geographical scope of the GHG mitigation supply curve forecasting exercise conducted as part of our larger effort to assist the NWPCC.

There are a number of technologies reported to be in development, but not covered in this report, that could significantly change the picture presented here. For example, some researchers are investigating the injection of CO_2 into magnesium-bearing rock strata, where the CO_2 would chemically react with the magnesium and be fixed. Other companies are investigating totally different sequestration approaches, like Calera's proposed technology to use seawater to produce a carbonate from flue gas, without the intermediate step of removing the CO_2 from the flue gas, and without the need to transport the CO_2. These and other technologies are not included in the current literature around CCS, and are difficult to evaluate from the standpoint of technical or practical potential. As climate change mitigation efforts evolve, however, and a price tag is attached to carbon, it is quite possible that completely new technologies like these will become key players in the CCS field.

1.1 Capturing CO_2

CCS involves the separation of CO_2 from flue gas in one of three ways:

1. *Post-combustion* - CO_2 is "scrubbed" from other flue gases after the burning of fossil fuel.

2. *Pre-combustion* - Fossil fuel is gasified rather than combusted and the CO_2 is captured from the exhaust stream.

3. *Oxy-fuel combustion* - Combusting fuel in an all-oxygen environment results in emissions of just CO_2 and water vapor, allowing for a pure, easily-transportable CO_2 stream.

Of these three options, *post-combustion* is currently the most widely used. The applied technology has been in existence for over 60 years and is commonly employed in industrial processes (IPCC 2005, 59). The *Pre-combustion* method is often seen in chemical plants and oxy-*fuel combustion*, while effective, involves processes that are extremely energy intensive and have yet to gain traction in the industrial or energy sectors.

1.2 Storing CO_2

After collecting the CO_2, it is then compressed and transported to the sequestration site via pipeline or tanker. Deep geologic sequestration can take place in a number of different types of subsurface formations. Of the possible sites for carbon storage, oil and natural gas reservoirs, coal seams, and deep saline formations exhibit the most potential for storage, although a variety of other formations are being explored.

1.2.1 Depleted Oil and Natural Gas Reservoirs

Oil and natural gas reservoirs are comprised of two layers of rock: a permeable layer where the oil or gas sits and a non-permeable layer, called a “caprock,” which prevents the oil or gas from escaping. Once the oil or natural gas in a reservoir has been extracted from a formation, CO_2 can then be injected into the permeable layer, while the caprock serves to keep the CO_2 in place.

Enhanced Oil Recovery (EOR) is the process of injecting CO_2 into an oil reservoir to improve the flow rate of the oil. CO_2, when combined with oil, decreases the viscosity of oil, which then increases the amount that may be extracted from a given reservoir. CO_2 also acts to displace the oil, pushing more of it to the production wellbore. EOR generally results in a 10 to 15 percent increase in the amount of oil recovered from a particular site (US DOE 2008, 18). Several pilot projects are currently exploring the use of CO_2 in natural gas fields and other uncommon applications, such as using the gas to repressurize depleted reservoirs.

1.2.2 Un-mineable Coal Seams

Coal contains many natural fractures, or “cleats,” which allow for the adsorption of a number of gases—including methane. Because coal has a higher affinity for CO_2 than for methane, CO_2 injected into coal systems will displace the methane and allow for its enhanced recovery. While the effectiveness of this process depends both on the type of coal and future plans for the coal bed, it still represents a promising avenue for carbon storage. Note that mining the coal from a site previously employing CO_2 injection would release all sequestered CO_2. Beds that are too deep or too thin for cost-effective mining are therefore the preferred CO_2 injection sites. Enhanced coal bed methane (ECBM) has yet to be employed commercially, and its effectiveness on a large scale has yet to be proven.

1.2.3 Deep Saline Formation Storage

Saline formations are porous layers of sedimentary rock within the earth’s surface which are saturated with formation water or brine and held in place by a caprock. Much more common than either oil and gas reservoirs or coal seams, this type of sequestration site is relatively untested. The salt content of the associated water makes the waters unfit for human use, and thus comparatively little research has been done on these formations (US DOE 2008, 20). Moreover, while existing well and mining infrastructure can assist with sequestration activities in oil and gas reservoirs and coal beds, comparable infrastructure does not exist around saline formations. On the other hand, successful pilot projects have done much to demonstrate the technical potential of this sequestration method.

2 CCS Costs

Three main components of the CCS process drive the overall cost of this GHG mitigation option. Carbon capture, transport and storage each have their own distinct cost challenges.

2.1 Capture

CO_2 capture is currently the most costly portion of the CCS process, and this cost varies widely depending on a number of factors as shown in Table 1 below.

Plant Type	Cost for Capture & Compression (per tCO_2)	Factors Driving Estimated Cost of Capture & Compression
Steam Rankine Power	25 - 60	• CO_2 content in flue gas stream • Capital cost • Energy requirements for solvent cycling
IGCC Power	25 - 40	• CO_2 content in flue gas stream • Capital cost
Refinery Flue Gas	35 - 55	• CO_2 content in flue gas stream • Capital cost • Energy requirements for solvent cycling (if applicable)
Steel	20 - 35	• CO_2 content in flue gas stream • Capital cost • Energy requirements for solvent cycling (if applicable)
Cement	35 - 55	• CO_2 content in flue gas stream • Capital cost • Energy requirements for solvent cycling (if applicable)
Ethanol (Fermentation)	6 - 12	• No capture cost for pure CO_2 stream • Compression cost only
Ethylene Oxide (Process Stream)	6 - 12	• No capture cost for pure CO_2 stream • Compression cost only
Ammonia (Reformer Gas)	6 - 12	• No capture cost for pure CO_2 stream • Compression cost only
Source: Dooley et al 2006, 33		

Table 1: The cost of CO_2 capture for various industrial processes

Capture costs depend significantly on the source from which the CO_2 is captured. Costs at coal or gas-fired power plants, for example, range from \$15 to \$75 per tonne CO_2, while hydrogen and ammonia production facilities face a range from \$5 to \$55 per tonne. Other industrial sources range from \$25 to \$115 per tonne of CO_2 captured (IPCC 2005, 11).

2.2 Transport

Unless a facility has been sited based on local CO_2 injection potential, captured CO_2 will need to be transported via pipeline or tanker to a disposal site. Tanker systems have not yet been employed on a scale that would serve for the large-scale transport of CO_2, whereas there are already over 3,600 miles of CO_2 pipeline in the US that serve existing EOR operations

(Fernando et al. 2008, 12). The cost of building and maintaining a new pipeline, however, is highly dependent on terrain. Costs may increase up to 100%, for example, if the pipeline intersects with urban or mountainous regions (IPCC 2005, 190). For a 250km pipeline, the IPCC predicts costs of transport ranging from $1 to $8 per tonne CO_2, with higher costs associated with a lower flow rate, and lower costs for a higher flow rate.

2.3 Storage

As with capture and transport, the likely cost of storing CO_2 in the US is highly variable. Studies project that injecting carbon into oil and gas reservoirs without enhanced recovery would cost from $0.50 to $4 per tonne stored for oil reservoirs and $0.50 to $12 for gas reservoirs. Variables that affect this cost include: a) the depth of the field, and b) whether existing equipment can be used to assist the storage process (IPCC 2005, 261). Storage costs may be offset with revenues experienced as a result of enhanced oil or gas recovery—as much as $25 per tonne—but the benefit received is highly dependent on oil and natural gas prices as well as individual site characteristics (McKinsey & Company 2007, 61). It is also the case that even modest levels of CCS in the US would simply overwhelm the market for CO_2 in EOR applications, and eliminate any such revenue benefit.

The costs of storage within saline formations are comparable to oil and gas reservoirs with projections ranging from $0.4 to $4.5 per tonne CO_2 stored. This number depends on: a) the depth and thickness of the formation, b) its permeability, c) the injection rate, and d) the number of wells at a site (IPCC 2005, 261).

Enhanced coal bed methane, as mentioned above, has yet to be proven commercially; the costs associated with this process are thus relatively unknown. Well-run sites could have negative costs if considering the sale of methane, but this result depends on storage costs and gas prices.

3 CCS in the WCI Region

This section of the report reviews the publicly available literature regarding the technical and practical potential of CCS in the states currently associated with the Western Climate Initiative (WCI). Those states and provinces include Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Ontario, Oregon, Quebec, Utah, and Washington.

3.1 Technical Potential

The technical potential for storing CO_2 in the Northwest and the rest of the WCI states is significant, as presented in Table 2. These technical potential numbers, however, do not take into account any economic or regulatory considerations.

Resource Estimates (million tonnes CO_2)							
	Enhanced Oil and Gas Recovery	Enhanced Coal Bed Methane		Deep Saline Formation Storage		Total	
		Low	high	Low	High	low	High
Arizona	70	0	0	184	740	254	810
British Columbia	/	/	/	749	749	749	749
California	7,692	/	/	75,875	303,502	83,567	311,194
Manitoba	618	0	0	/	/	618	618
Montana	1,262	293	293	265,407	988,831	266,962	990,386
New Mexico	8,246	78	310	32,186	128,744	40,510	137,300
Ontario	/	0	0	1	3	1	3
Oregon	/	/	/	16,727	66,909	16,727	66,909
Utah	1,410	30	120	32,565	128,990	34,005	130,520
Washington	0	2,800	2,800	90,245	360,979	93,045	363,779
Source: US DOE 2008, 139							

Table 2: Resource estimates for the Northwest

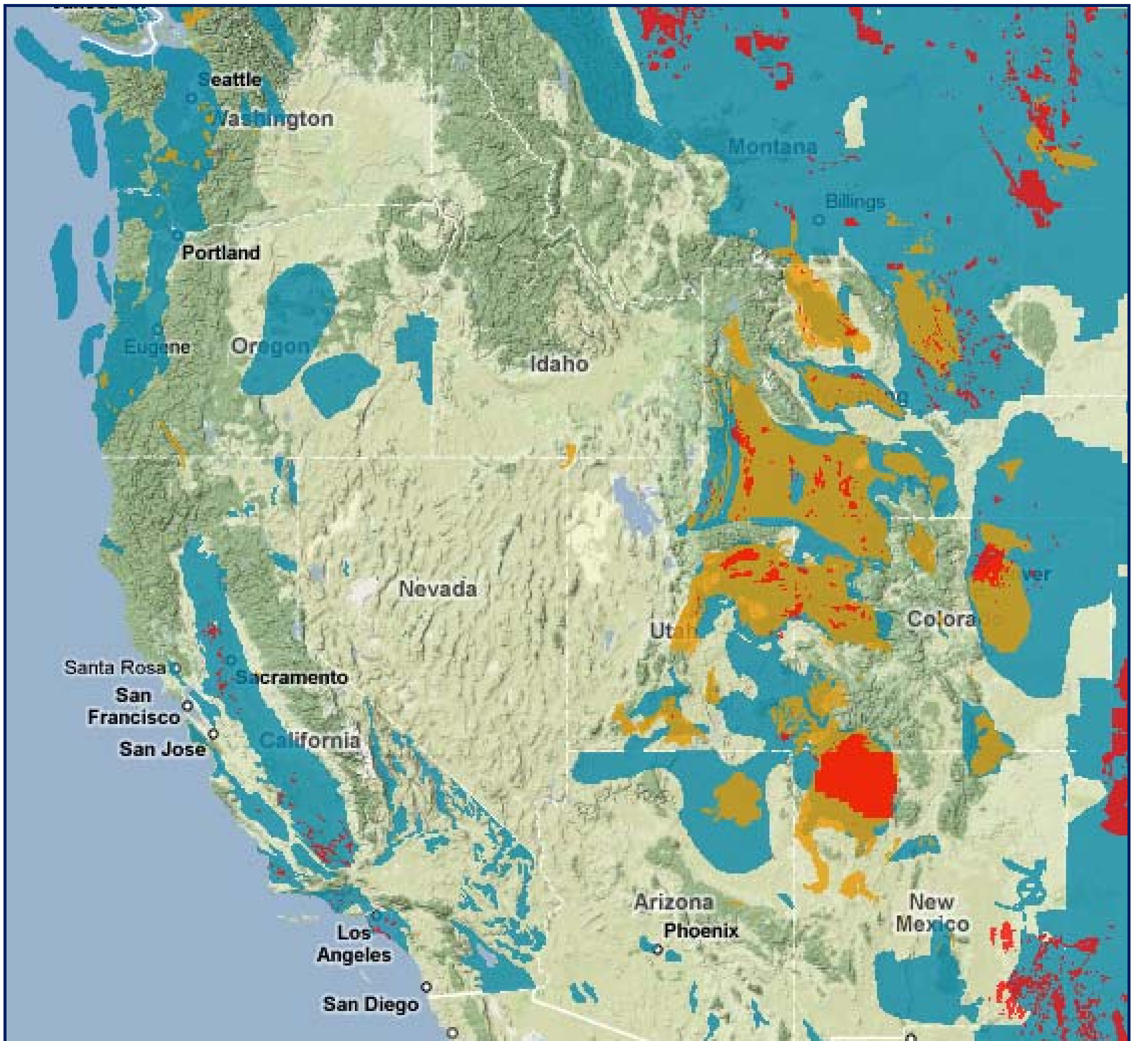
As shown in Table 2, the ability of the WCI states to store CO_2 in oil and gas reservoirs is modest, ranging from an estimated 0 tons in Washington to more than 7 billion tons in California and 8 billion tones in New Mexico. In the Pacific Northwest, Montana and Utah have at least a reasonable amount of potential.

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) estimates that California's oil reservoirs, mostly found in the San Joaquin Basin, the Los Angeles Basin and the southern coastal basins, have a CO_2 EOR storage potential of approximately 3.4 billion metric tons. The gas reservoirs in the Sacramento River Delta are estimated to have a CO2 storage capacity of 1.7 billion metric tons.

The ability of the WCI states to store CO_2 in un-mineable coal seams ranges from 0 tons to almost 3 billion tones. WESTCARB also investigated the ability to store CO_2 in the coal basins of the West Coast. The group found three promising storage sites in the Pacific Northwest. These locations include the Bellingham Basin in Washington, the Upper Puget Sound region and the small, deep coal deposits of southwestern Oregon. The coal beds in Puget Sound, for example, are estimated to provide approximately 2.8 billion metric tons of CO_2 storage capacity. Washington's coal bed deposits in the Puget Sound are currently hosting pilot projects to assess their injectivity and storage potential (DOE 2008, 92-96).

The estimated ability of the WCI states to store CO_2 in saline aquifers is much larger than in the region's oil and gas reservoirs and un-mineable coal seams, ranges to almost one trillion tones in Montana. California has 10 sedimentary basins containing saline formations which promise to offer an estimated 75 to 300 billion metric tons of CO_2 storage capacity. Oregon and Washington contain a combined 7 sedimentary basins with a total estimated CO_2 storage capacity of 20 to 85 billion metric tons (WESTCARB, http://www.westcarb.org/about_overview.htm).

Figure 1 illustrates the geographical distribution of CCS potential in the Northwest.



Oil and Gas Reservoirs	Unmineable Coal Seams	Deep Saline Formations

Source: NatCarb 2008

Figure 1: Geographic Distribution of Potential CCS in the Western US

3.2 Practical Potential

While the technical potential for CCS in the WCI states, and in the Pacific Northwest specifically, is significant, the amount of this potential that will actually be developed and become available for power plant use hinges on a number of variables. Among the most significant variables that will affect the deployment of CCS technology are:

- *Environmental Policy*. Due to the high cost of capture and storage, the CCS technologies described here will not be deployed on a significant scale without significant emissions reduction mandates. Moreover, the sectors touched by policy will also have a significant effect on probable deployment. Apart from power plants, large emitters in the Northwest include iron and steel plants, cement plants, refineries, gas processing facilities, and chemical plants (Dooley et al 2006, 29). The prevalence of CCS will depend on which of these emission sources are included in GHG emissions reduction mandates. Note: the most current iteration of the WCI cap-and-trade program includes all electricity generation and any industrial sources that emit more than 25,000 metric tons CO_2e.

The use of flexible mechanisms also has a bearing on the implementation of CCS technology. All things being equal, the greater the use of carbon trading, the lower the price of carbon is likely to be, and the more challenging it will be to justify the multi-billion dollar financial commitments associated with a major CCS project.

- *Advances in Technology*. The various technologies included under the umbrella of CCS are at various stages of maturity, as evidenced in Table 3 below. As market experience with CCS systems grows and energy demands are addressed by focused R&D (current capture technologies include a very significant energy penalty), the costs of CCS could decline. One study goes so far as to predict that the economic potential of CCS will increase by 150 percent if CCS technological learning follows the pace of sulphur removal technologies (IPCC 2005, 351).

Technical Components of CCS				
CCS Component	CCS Technology	Demonstration Phase	Economically Feasible Under Specific Conditions	Market Mature
Capture	Post-combustion		X	
	Pre-combustion		X	
	Oxy-fuel combustion	X		
Transport	Pipelines			X
	Shipping		X	
Storage	Enhanced oil recovery			X*
	Oil and gas reservoirs		X	
	Saline formation		X	
	Enhanced coal bed methane recovery	X		
* CO_2 injection for EOR is a mature market technology, but when used for CO_2 storage, it is only economically feasible under specific conditions				
Source: IPCC 2005, 8				

Table 3: Current maturity of CCS system components

- *Siting and Liability Issues.* Serious questions regarding the effectiveness and safety of CCS systems have been raised among the general population, leading to major challenges to the technology in terms of siting and liability issues. Whether these challenges can be overcome, and how much any solution to these challenges would add to the cost of the technology itself, is still speculative. Liability and siting issues have the potential to derail any meaningful adoption of CCS systems.

- *The Price and Quantity of Coal and Natural Gas in a Given Region*. Because the carbon capture process itself is quite energy intensive, regions where coal is relatively abundant and cheap will be more likely to employ CCS than those where a less carbon-intensive fuel is more commonly employed.

At the end of the day, even global projections of how CCS will be deployed vary widely. Many researchers predict that large-scale implementation of capture and storage technology will not occur before 2015, while others believe that 2030 is the earliest plausible date. Some models suggest that sustained CO_2 prices of $30/metric ton would be sufficient to make CCS economically viable for power plants (WRI 2008, 17), while others predict that prices of $50 to $100 would be necessary (IPCC 2007, 300).

In its Fourth Assessment Report, the Intergovernmental Panel on Climate Change places total world capture potential from 2015 to 2030 at 23 billion tonnes of CO_2 (note that this figure only includes CCS systems within coal- or gas-fired power plants and not any other industrial processes). The scenarios being used by the International Energy Agency, however, range widely in the assumed deployment of CCS. One scenario estimates that CCS will be part of 9 percent of power generation by 2030 and 16 percent by 2050, while projections from another scenario have CCS systems employed in 12 percent of power generation in 2030 and 30 percent by 2050 (IEA 2008, 29).

Energy and Environmental Economics, Inc. (E3) recently led a project for the California Public Utilities Commission that analyzed the various costs associated with potential CCS systems in the western U.S. The data as summarized in Table 4 provides a useful reference for estimating regional costs.

	2008 Value	Range of 2008 Values in Model
Base overnight capital cost ($/kW)	3,418	3,144 - 4,101
Variable O&M ($/MWh)	4.50	4.50
Fixed O&M ($/kW-yr)	46.11	42.42 - 55.33
Nominal Heat Rate (BTU/kWh)	9,713	9,713
Capacity factor (%)	85	85

Table 4: Coal IGCC with CCS Cost, Resources, & Performance

A CCS equipped IGCC plant with the characteristics specified in Table 4 would generate energy at a levelized cost of approximately $142 per MWh. Relative to a natural gas CCGT plant with a levelized cost of $52 per MWh, the implied cost of carbon for this plant is almost $400. We should be careful not to read too much into such estimates and the uncertainties that are built into them, but the analysis does provide insight into the challenges of deploying CCS in the region.

4 Conclusions

Translating the various uncertainties and projections shown above into an assessment of CCS practical potentials in the Pacific Northwest in the near- to mid-term is almost impossible. While there is significant technical potential to store CO_2 in the Pacific Northwest, the region is unlikely to significantly influence either the pace of public policy around emissions mandates, or the pace of technology development around CCS itself. Given the very large upfront costs associated with CCS facilities, as well as the siting and liability issues involved, it is unlikely that policy initiatives in the Pacific Northwest alone could plausibly incentivize the commercial deployment of any of the CCS technologies described in this report.

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