WORKING PAPER

Carbon Capture, Pipeline and Storage: A Viable Option for North Carolina Utilities?

Prepared by the Nicholas Institute for Environmental Policy Solutions and The Center on Global Change, Duke University

March 8, 2007

Eric Williams[1]
Nora Greenglass[2]
and Rebecca Ryals[3]

[1] *Project Director, Climate Change Policy Partnership, Nicholas Institute for Environmental Policy Solutions, Duke University*
[2] *Former Graduate Student, Nicholas School of the Environment and Earth Sciences, Duke University*
[3] *Former Graduate Student, Nicholas School of the Environment and Earth Sciences, Duke University*

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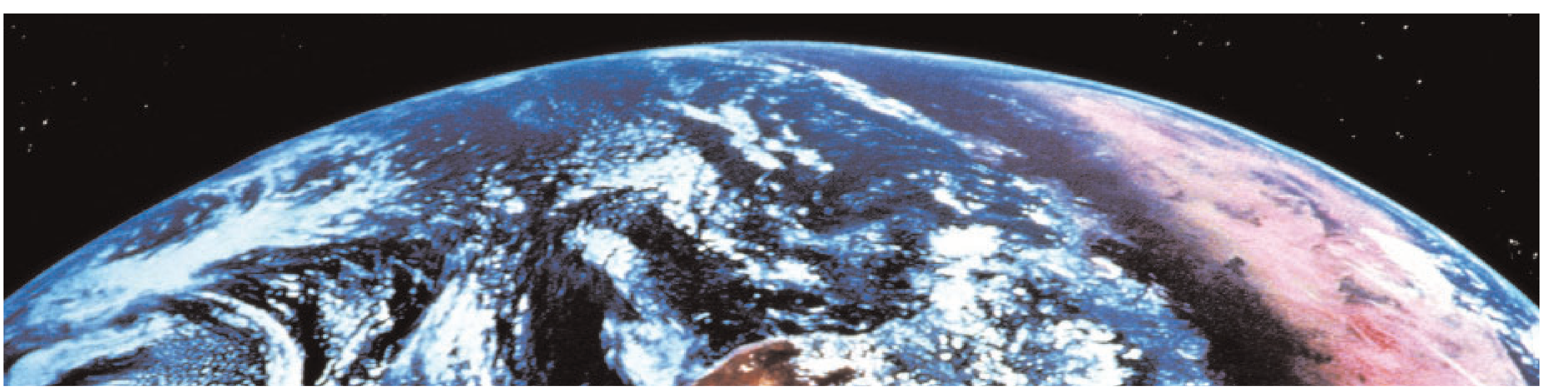

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EXECUTIVE SUMMARY

The Intergovernmental Panel on Climate Change (IPCC) concluded in 2001 that countries must reduce global greenhouse gas emissions to 25% below 1990 emissions by 2050 to reach climate stabilization at 450 ppm, or 45% above 1990 emissions to reach 550 ppm. Stabilization at either 450 ppm or 550 ppm will be difficult to achieve and may still carry considerable risk of major climate events. While reduction goals for specific countries vary by political proposal, developed countries like the United States must reduce emissions in the range of 80% below 1990 emissions by 2050 for 450 ppm, or 60% for 550 ppm.[4]

If North Carolina is going to meet an objective consistent with the US target, all viable options within the state for reducing GHG emissions must be explored, and the biggest contributor to NC emissions, the electricity sector at 41%, must play a critical role. Because coal contributes 98% of electricity sector emissions in North Carolina, any credible GHG reduction strategy must address the current usage of coal, conventional pulverized coal plants. The two ways to reduce carbon emissions from coal are to improve the efficiency of combustion and to capture and store carbon in geologic reservoirs.

Two new coal technologies can improve efficiency over conventional subcritical pulverized coal plants – supercritical pulverized coal (SPC) and integrated gasification combined cycle (IGCC). Although carbon can be captured within both SPC and IGCC plants, the process of gasifying coal in IGCC plants promises the lowest capture cost at the present time.

Viewed through a political lens, IGCC holds great promise. The United States will use the reserves of its most abundant fuel resource – coal – to decrease its dependence on foreign sources of energy. IGCC is a technology that can command the political support of stakeholders seeking to protect the environment and those seeking to secure an economic future for coal – a powerful political combination.

Within the next decade, utilities plan to construct new coal-based generation in North Carolina. In this assessment, we evaluate options for building IGCC with and without CCS and building SPC with and without CCS and for storing carbon inside and outside North Carolina. While this analysis focuses on North Carolina as a starting point, elements of the analysis can be applied to other states seeking emission reduction opportunities.

Key findings are:

- *At around $7 per ton* CO_2[5]*, IGCC with the option for carbon capture is expected to be less expensive over its lifetime than SPC with the option for carbon capture.*

  Based on EPA technology cost estimates, IGCC is likely a lower cost option than SPC if CO_2 prices are at least $7 per ton in 2012. The cost of adding CCS to IGCC is expected to be lower than adding it to SPC. While the initial cost of IGCC is higher than SPC, moderate to high expected CO_2 prices are sufficient to tip the scale in favor of IGCC because IGCC is more efficient and therefore has lower emissions (CO_2 and criteria air pollutants), and the process of capturing CO_2 is less energy-intensive and less expensive. The real cost of IGCC with carbon capture and SPC with carbon capture is uncertain. Publicly available cost estimates suggest that CO_2 prices above $6 (EIA), $7 (EPA), and $13 (Wisconsin) per ton are needed to make the IGCC option preferable. From an economic perspective, the choice of building SPC or IGCC depends largely on the expectation of future CO_2 prices. In a low CO_2 price world, SPC is likely the best bet. In a middle CO_2 price world, the choice may be a toss-up, especially before IGCC technology is fully commercialized. SPC capture technology is less certain than IGCC at

[4] Reduction targets are from a presentation, "A comparison of Approaches for International Climate Policy Post 2012" by Nicholas Hoehne of ECOFYS. http://www.ccap.org/Presentations/FAD/2006/Hoehne-Post%202012%20regimes%20APR%2020.pdf

[5] Unless otherwise noted, carbon prices cited in this paper are assumed to begin in 2012 and to increase at 5% per year thereafter over the life of the plant. A levelized CO_2 price of $15 is equivalent to one starting at $7 in 2012 increasing 5% per year.

this point, so SPC with CCS may be as risky as IGCC. But in a high CO_2 price world, the optimum choice seems clearly to be IGCC despite the risks.

- *IGCC without carbon capture is more expensive than SPC without carbon capture for* CO_2 *prices under $22 per ton.*[6]

  Costs for new power plants are increasing rapidly as world-wide demand for primary materials has increased. To the extent that IGCC plants require more primary materials, the increase in IGCC costs may be slightly greater than with SPC. Furthermore, IGCC costs are uncertain because no full-scale commercial IGCC plant has been constructed. After the first several commercial-scale plants have been built, the cost of IGCC is expected to fall and become more stable. The most recent publicly available, vetted cost information suggests that construction of a supercritical pulverized coal plant will cost around $1,430 per KW[7] for a levelized cost of electricity of $53 per MWh, assuming the full cost of NOx, SO_2 and mercury emissions at EPA forecasted emission prices. An IGCC plant is expected to cost around $1,670 per KW[8] for a levelized cost of electricity around $56 per MWh. Because IGCC is an immature technology, actual costs may differ from estimates. Based on these assumed costs, with CO_2 prices above $22 per ton, IGCC becomes less expensive than SPC. EPAct 2005 provides $800 million in tax incentives for coal gasification projects (up to 20% of project costs). An additional $200 million per year for nine years is available for loan guarantees and direct grants. Any available incentive will improve IGCC's position relative to SPC.

- *Geologic sequestration is not economically or technically feasible within North Carolina*

  An assessment of geologic storage in North Carolina reveals little available storage capacity. The best in-state option can store only 29.91 $MMTCO_2$, about three year's worth of captured CO_2 (assuming around 1,600 MW of generating capacity). A new pipeline would be required to transport the CO_2 to the reservoir, making the project economically infeasible.

- *CCS may be viable if the captured $_{CO2}$ is piped out of North Carolina and stored elsewhere*

  Carbon dioxide emissions captured from North Carolina coal plants could be transported to viable geologic sinks in the Appalachian Basin or Gulf Coast region, requiring the construction of a multi-state pipeline on existing rights of way along the East Tennessee and Texas Eastern natural gas pipelines. The lowest-cost pipeline and storage option for plants in North Carolina is to build a multi-state pipeline capable of supporting the transfer of CO_2 from around 10,400 MW of capacity feeding in along the pipeline route. The timing of the carbon capture and pipeline system dramatically affects the net present value (NPV) of the whole system, and the price of CO_2 has considerable influence over the timing of building capture equipment and pipeline. The optimal timing of the pipeline for a given CO_2 price is different with IGCC than with SPC. At a CO_2 price of $7.2 per ton ($15 per ton levelized)[9], IGCC becomes cost-effective on a NPV basis, assuming CCS is brought on-line in 2027. This scenario would avoid almost 800 million tons of CO_2 over its lifetime compared to SPC with CCS (CCS and pipeline beginning in 2039).

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[6] Unless otherwise noted, carbon prices cited in this paper are assumed to begin in 2012 and to increase at 5% per year thereafter over the life of the plant. A levelized CO_2 price of $45.8 is equivalent to one starting at $22 in 2012 increasing 5% per year.
[7] EPA, *Environmental Footprints and Costs of Coal-Based. Integrated Gasification Combined Cycle and.Pulverized Coal Technologies*, July 2006.
[8] Ibid.
[9] Unless indicated to be levelized, CO2 prices reported in this document are the initial prices in 2012 that are assumed to grow 5% per year. A levelized CO2 price is the equivalent flat price over the time horizon.

INTRODUCTION

Scientific consensus, growing public awareness and real-time events may soon drive the U.S. to a mandatory climate policy. Legislators, regulators and industry executives from a wide array of market sectors increasingly understand that climate change adaptation and mitigation require planning now and action soon.

Fossil-fuel generated electricity accounts for one-third of carbon dioxide emissions in the U.S.; electric utility companies can therefore provide leadership in technology and policy development through careful investment decisions for future generation capacity. In so-doing, climate change mitigation, technological adaptation and innovation merge; forward looking companies gain the opportunity both to serve the public interest and thrive in a carbon constrained future.

Electric utilities have a portfolio of mitigation options available, including investment in renewable energy technologies, demand side management and energy efficiency programs, increased nuclear energy generating capacity, cleaner coal technologies and carbon capture and storage (CCS). Because coal is an abundant and relatively inexpensive feedstock for energy, reductions and/or offsets of carbon dioxide emissions from coal-fired power plants are particularly important.

For offsets, one possibility is that photosynthesis and other biological processes capture and store (sequester) carbon in natural "sinks," such as forests. For direct reductions, relatively recent technology advances enable carbon dioxide capture from fossil fuel combustion. In this case, carbon dioxide from large point sources can be concentrated, transported and stored in geologic reservoirs.

This analysis will assess the costs and benefits of building IGCC with CCS versus that of supercritical pulverized coal technology with and without CCS. The key questions considered include:

- Are emerging technologies to capture and store carbon dioxide economically feasible?
- What is the technical and economic feasibility of geologic sequestration in North Carolina?
- What technical and cost-effective options might be available for geologic sequestration outside of North Carolina?

IGCC TECHNOLOGY

Integrated gasification combined cycle (IGCC) is a proven technology that when coupled with carbon capture and storage (CCS) can reduce nearly 90% of CO_2 emissions into the atmosphere from coal combustion. Although well-proven in concept, IGCC has not been fully commercialized, and costs for commercial scale applications are only estimates, not proven. As with any newer technology, a utility that builds an IGCC plant faces the risk that actual costs may well exceed estimates and that the technology may not be as reliable as more widely applied technologies like pulverized coal. These risks are not quantified in this paper, though they are not insignificant. Despite the risks, IGCC with CCS may be a viable approach to fossil fuel based electricity in a carbon constrained economy, especially with the assistance of policy to help minimize the risks.

IGCC converts fuel stock such as coal, petroleum coke, orimulsion, biomass or municipal waste to low heating value gas, comprised mostly of carbon monoxide and hydrogen, in a process called gasification. The gas is then used as the primary fuel for a gas turbine, which generates electric power. Heat generated during the process is also captured to power steam turbines which in turn produce additional power.[10]

[10] The Energy Blog, 2005.

IGCC consists of four basic steps:

1. **Gasification**

Feedstock such as coal or petroleum coke is pulverized and fed into the gasifier (reactor) along with oxygen that is produced in an on-site air separation unit. The combination of heat, pressure, and steam breaks down the feedstock and creates chemical reactions that produce hydrogen (H_2), carbon monoxide (CO) and synthesis gas, or syngas. Feedstock minerals become an inert, glassy slag product used in road beds, landfill cover, and other applications.

2. **Syngas Cleanup**

Syngas must be purified before it can be used as a gas turbine fuel. Syngas purification results in high-pressure steam. This cleanup process removes sulphur compounds, mercury, ammonia, metals, alkalytes, ash and particulates to meet the turbine's fuel gas specifications. These compounds can in turn be used to manufacture commercial products such as elemental sulphur, methanol, ammonia, fertilizers and other chemicals. Hydrogen can also be separated and recovered at this point for further energy production,[11] although doing so would reduce the heating value of the remaining gas sent to the gas turbine and reduce its power output.

As a result of this purification process, CO_2 is 80-90% concentrated (volume/volume) within the flue stream and can be vented to the atmosphere or sequestered (see below).[12]

3. **Power Generation: Gas Turbine Combined Cycle**

Following purification, syngas flows to the gas turbine where it is burned to drive the turbine and generate power. The nitrogen from the air separation unit is expanded through the turbine to increase power production and reduce NOx emissions. The steam from the gasification process is combined with steam produced by the gas turbine exhaust in the heat recovery steam generator and fed to a steam turbine-generator.

4. **Cryogenic Air Separation**

A cryogenic air separation unit provides pure oxygen back into the gasification reactor described in step 1, above.[13]

IGCC Plant Considerations

The physical size of an IGCC plant is comparable to a conventional coal-fired power plant; unlike a conventional coal plant, an IGCC plant does not require additional area for scrubber sludge treatment or ash dewatering. Water consumption of an IGCC plant is approximately 30 percent lower than a conventional coal plant. Also, lime or limestone is not required for desulphurization.[14]

IGCC SO_x, NO_x, and particulate emissions are fractions of those produced by conventional pulverized coal boiler power plants. IGCC gas turbines do not require expensive back-end flue gas mercury removal systems. Activated carbon bed filters in syngas and recycled water streams remove 90 to 95 percent of the mercury for only $20 to $30 per kW installed.[15]

As mentioned in process step 2, above, IGCC plants enable carbon dioxide removal before combustion to create a more hydrogen-rich fuel. In conventional boiler plants, carbon dioxide is removed from the exhaust

[11] Joshi & Lee, 1996.
[12] GE Energy, 2006b.
[13] GE Energy, 2006b.
[14] GE Energy, 2006b.
[15] GE Energy, 2006a.

gas after combustion, which is less efficient and more expensive due to the larger gas volume from post-combustion cleanup. To remove CO_2, the syngas, which also contains significant amounts of carbon monoxide (CO), is combined with steam in a shift reactor to produce additional hydrogen and CO_2. This concentrated carbon dioxide stream (approximately 80-90%) can be captured and used for commercial applications or sequestered in a geologic reservoir to reduce the level of greenhouse emissions resulting from fossil fuel-based power generation. The remaining 10% to 20% of CO_2 is released to the atmosphere.

Current Status

Several IGCC pilot and demonstration plants operate across the U.S. and abroad to convert synthetic gas to power. (Table 1).

Table 1. **OPERATING IGCC PLANTS**[16,17,18,19,20]

Project	Year On-Line	Net Output (MW)	Primary feedstock	Design efficiency	Capital cost
Polk County IGCC Project	1996	250	Coal	42%	$1650/KW $424 Million
Wabash River Energy Ltd	1995	260	Petcoke	38%	$1660/KW $430 Million
Delaware Clean Energy Cogeneration Project	2002	160	Fluid petcoke	No data	$380 Million
El Dorado Gasification Power Plant	1996	35	Petcoke, natural gas, refinery waste	No data	$2150/kW $80 Million
ISAB Energy (Italy)	1999	512	Asphalt		$1200 Million
Falconara Marittima (Italy)	2000	550	Heavy oil	38%	$1530/KW $444 Million
Elcogas Puertollano (Spain)		335	High ash coal, petroleum coke	47%	$894 Million
Nippon Oil Negishi (Japan)	2003	342	Asphalt residue	39%	$1,000/kW
William Alexander Plant (Netherlands)	1994	253	Bit. coal	43%	

[16] The Energy Blog, 2005.
[17] Gasification Technologies Council, 2005.
[18] Smith, 2003.
[19] CRE Group, Ltd., 1999.
[20] Schimmoller, 2005.

As of May 2006, several plants have been proposed in the United States to create power from synthetic gas (Table 2). According to the Gasification Technologies Council, three (Lima Energy IGCC Plant, Mesaba Energy Project and Southern Illinois Clean Energy Center) are registered as developmental plants to produce electrical power from syngas.[21]

Table 2. IGCC under development (US)[22]

Sponsor	State	Proposed Location	Size, MW	Start-up	$ millions	Fuel Type	DOE Clean Coal Power Initiative Funding
Orlando Utilities Comm.	Florida	Orange County	285	2010	$750	Bit. Coal	$235 million
Southeast Idaho Energy	Idaho	Pocatello	520	2010	$850	Bit. Coal	
Clean Coal Power Resources	Illinois	Fayette County	2,400	TBD	$2,800	Pet coke	
Madison Power Corp.	Illinois	Williamson County	545	TBD	$2,000	Bit. Coal	
Erora Group	Illinois	Taylorville	677	TBD	$700	Bit. Coal	
Steelhead Energy Co.	Illinois	Williamson County	545	TBD	$600		
Duke Energy	Indiana	Edwardsport	600	TBD	$900	Bit. Coal	
Tondu Corp	Indiana	St. Joseph County	640	TBD	$1,000	Bit. Coal	
Global - Kentucky Pioneer	Kentucky	Clark County	540	TBD	$520	Coal, refuse derived fuel	
Synfuel	Oklahoma	Enid	600	2004	$600		
Excelsior Energy, Mesaba							
Energy Project	Minnesota	Hoyt Lake	531	2011	$1,200	Bit. Coal	$36 Million
American Electric Power	Ohio	Meigs County	600	2010	$1,288	Coal, some pet coke	
Global Energy	Ohio	Lima	580	2007	$575	Bit. Coal	
DKRW	Wyoming	Medicine Bow	350	2008	$2,500	Bit. Coal	
Waste Management and							
Procecessors Inc. (WMPI)	Pennsylvania	Gilberton	41	2008	$612	Bit. Coal	$100 million
FirstEnergy/Consol	Ohio or PA	Undecided	TBD	TBD	TBD		
Energy Northwest	Washington	Western WA	600	2011	950		

IGCC Federal Funding

The Energy Policy Act of 2005 (EPAct 2005) offers a 20% investment tax credit for the gasification portion of an IGCC plant, which amounts to a 14% overall credit for the entire project. EPAct 2005 provides a limit of $800 million in tax credits, implying support for around 6 IGCC plants.[23] This funding will likely be highly competitive.

SUPERCRITICAL PULVERIZED COAL

Pulverized coal (PC) is a mature technology in reliable operation for many years. PC units operate by blowing finely ground bituminous coal and combustion air (sometimes secondary and tertiary air is added) into a boiler plant through a series of nozzles. The pulverized coal is a fine powder with less than 2 percent content at +300 µm and 70-75 percent content below 75 µm. This content is needed so that complete combustion can occur within the 2-5 seconds of particle residence time. Depending on coal rank, combustion takes place at temperatures from 1300-1700°C and near-atmospheric pressures. Except for very high ash content coals, PC is appropriate for most coal types.[24]

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[21] Gasification Technologies Council, 2006.
[22] Modified from Falsetti, 2006.
[23] Wilson, T., 2005
[24] IEA Clean Coal Centre, 2006.

Supercritical PC plants are the current best available technology for pulverized fuel combustion technologies. Supercritical refers to steam condition of 3,500 psig and temperatures up to 1050 ºF, both higher than subcritical PC. As of 2004, 117 supercritical plants are in operation in the United States.

CARBON CAPTURE AND GEOLOGIC STORAGE

I. Overview of Carbon Capture Technology

Coal combustion results in effluent flue gas released at atmospheric pressure containing 10 to 15% CO_2 by volume.[25] In order for CO_2 to be stored in geologic formations, it must be separated from the other flue gas constituents, purified to remove trace contaminants, and compressed from atmospheric pressure (1 atm) to pipeline pressure (100 atm). This energy intensive process requires the installation of new technologically advanced scrubbers, membranes, and compressors.[26]

Oxyfuel and post-combustion are primary methods for carbon capture from pulverized coal facilities. They are significantly more expensive than capture from IGCC facilities and are not as far along in the R&D and commercialization process.[27,28,29]

The CO_2 from the syngas produced during gasification can be separated using absorption or membrane methods, at an efficiency of 95%.[30] The hydrogen produced through the pre-combustion capture method is then burned in a combustion turbine to produce steam, resulting in additional electrical power generation.[31]

The installation of carbon capture systems adds around 40% to the capital cost of IGCC plants and around 75% to the capital cost of SPC. Because carbon capture requires power drawn either directly from the electric generator or the boiler in the form of high energy steam, capturing CO_2 imposes an energy penalty of 18% - 23% for IGCC and 30% - 44% for SPC. Additional generation capacity must be installed to keep net generation output at pre-capture levels. The analysis in this paper assumes that additional capacity is constructed to keep generation constant; more additional SPC capacity is needed than additional IGCC capacity because of the higher energy penalty for SPC.

II. CO_2 Transportation

Carbon dioxide captured in its gaseous form at ambient pressure (1 atm) must be compressed to pipeline pressure (100 atm) before transportation and storage.[32] At pressures above 73 atm and temperatures above 31.1° Celsius, CO_2 exceeds its critical point and enters the supercritical phase, a homogenous state with properties midway between those of a gas and liquid.[33] These physical properties enable CO_2 shipment by rail, ship, or truck, but the lowest cost option is transport by pipeline; 3,000 miles of commercial CO_2 pipeline for enhanced oil recovery operate in the United States today.[34]

Unique engineering and safety considerations for large scale CO_2 piping projects include:

- CO_2 must be completely dehydrated to prevent carbonic acid formation and degradation of the pipeline;

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[25] Angelelli, 2006.
[26] Dalton, 2004; Gibbins & Crane, 2004; Heddle et al., 2003.
[27] Newell & Anderson, 2004; US DOE, 2006.
[28] Newell & Anderson, 2004.
[29] Herzog, 1999; Newell and Anderson, 2004; Sekar, 2005
[30] Anderson and Newell, 2004.
[31] Rosenberg, 2006.
[32] Newell & Anderson, 2004.
[33] Bachu, 1999; Kaszuba et al, 2003.
[34] Dooley et al., 2006.

- Supercritical CO_2 physical and chemical properties necessitate the use of specific materials and sealants;
- Since CO_2 is denser than air, a large accidental release, though unlikely, would, in most cases, dissipate quickly and not pose any danger, but in the right topographical location may become trapped at ground level, presenting a hazard to humans and other animals in the immediate vicinity of the release.

Despite these challenges, industrial system failures and resulting adverse environmental or health effects are reportedly rare. Cost-effective system management and risk mitigation measures are therefore possible not only for existing US CO_2 pipelines, but for new infrastructure as well.[35]

The cost of constructing a dedicated CO_2 pipeline depends on the length and diameter of the pipeline, the cost of the right of way on which it is constructed, and the type of terrain through which it travels.[36] The length of the pipeline is determined by the distance from the CO_2 source to the geologic reservoir injection site. The diameter of pipeline required is proportional to the maximum flow rate of CO_2 emitted at the source.[37] Adequate pressure maintained along the pipeline ensures delivery of the gas at a pressure suitable for injection.[38] Generally, of the total up-front costs, right of way costs comprise approximately 5-10%, miscellaneous costs account for 20%, labor expenses account for 45-50%, and materials comprise approximately 25%.[39]

III. CO_2 Storage in Geologic Reservoirs

Suitable rock formations for geological sequestration are typically hundreds of meters below the land surface, requiring CO_2 at or above pipeline pressure during injection. The specific injection pressure required is a function of depth to the target formation, the quantity of CO_2 to be stored, and the volume and physical properties of the geologic sink.[40] Additional compressors and pumps are required at the site if the injection pressure must be greater than 100 atm.

There are currently three viable targets for CO_2 storage in geologic formations—depleted or diminishing oil and gas reservoirs, unmineable coal seams, and saline aquifers.

1. Depleted or diminished oil and gas reservoirs currently serve as geologic sinks. The extraction of oil and natural gas from reservoir rocks leaves empty pore space in the reservoir formation; injected supercritical CO_2 fills the space and remains sequestered within the reservoir rock.[41] In a partially depleted reservoir, some of the original fossil resources remain in the rock, inaccessible by standard extraction techniques. Carbon dioxide injected into these pore spaces increases pressure and reduces viscosity , forcing the remaining oil (or gas) out and to the surface.[42] Carbon dioxide in the pore spaces of the reservoir rock remains sequestered as long as its pressure does not exceed that of the original formation and its contents. The pressure required to maintain CO_2 in its stable supercritical phase necessitates storage reservoirs at least 800 meters below the surface injection point.[43]

[35] Kinder Morgan, 2006; Newell & Anderson, 2004.
[36] Crump and Foley, 2003.
[37] Herzog et al., 2006a.
[38] Electric Power Research Institute, 2002; Smith et al, 2001.
[39] Crump and Foley, 2003.
[40] Smith et al, 2001; Stevens et al, 2001.
[41] Hovorka et al, 2006.
[42] Newell and Anderson, 2004; Stevens et al, 2001.
[43] Brennan and Burress, 2003; IPCC, 2005.

Carbon dioxide stored in this manner hypothetically remains sequestered from the atmosphere for thousands of years. However, concerns exist regarding possible leakage of CO_2 from capped wells due to well failures or undetected fractures.[44]

2. Unmineable coal seams in the U.S. may also provide geologic reservoirs for CO_2 and provide opportunity for cost-effective recovery of coal bed methane. According to the United States Geological Survey, the majority of coal seams in the United States are unmineable; seams deeper than 800 meters cannot be reached with current mining techniques.[45]

   Normally, methane gas is adsorbed onto coal. Under the pressure and temperature conditions present at 800 meters or below, injected CO_2 will readily adsorb onto the surface of coal molecules, displacing the methane gas and forcing it toward the surface. Methane may then be captured and collected at the surface. Since this is a relatively new technology, further work is needed to determine the physical and geochemical reactions that lead to the sequestration of CO_2 and what factors may result in leakage.

3. Supercritical carbon dioxide can be sequestered in deep saline aquifers at least 800 meters below the land surface via three physical and chemical reactions between the CO_2 and formation waters: displacement of formation waters, molecular and convective diffusion, and chemical reactions between CO_2, formation waters, and the host rock mineralogy.[46]

   Upon injection, supercritical CO_2 displaces formation waters. Almost immediately after injection, a very small fraction of the CO_2 dissolves into the surrounding brine, resulting in solubility trapping of CO_2 within the aquifer. Diffusion of CO_2 through the formation water proceeds on a molecular level in a process that can take thousands to tens of thousands of years to completely distribute CO_2 throughout an aquifer.

   Convective diffusion occurs due to the density difference between aquifer waters containing dissolved CO_2 and waters not containing CO_2. This mixing occurs orders of magnitude faster than pure molecular diffusion of CO_2 and continues until the dissolved CO_2 reaches equilibrium with respect to formation waters. Once dissolved in brine, CO_2 may remain sequestered in a deep aquifer for thousands of years under constant temperature and pressure conditions.[47]

   In addition, mineral reactions between dissolved CO_2 and the formation waters or the host rock mineralogy also sequester carbon within saline aquifers in processes known collectively as mineral trapping. The reaction of CO_2 with dissolved constituents within saline water may result in the precipitation of carbonate minerals stable on geologic time scales.[48]

The identification of potential carbon sinks necessitates an in-depth examination of regional geologic characteristics. Extensive geophysical exploration is usually necessary to determine the approximate volume of a sink, as well as any potential weaknesses in the structural integrity of the formation. Prior to full-scale injection of carbon dioxide into a reservoir, a test well is drilled and pilot testing is performed, during which carbon dioxide is injected and tracked as it moves throughout the subsurface.[49]

[44] Newell and Anderson, 2004; Nordbotten et al, 2005.
[45] Friedmann, 2003; IPCC, 2005.
[46] Kaszuba et al, 2003.
[47] Eniss-King and Paterson; Xu et al, 2006.
[48] Brennan and Burress, 2005; Xu et al, 2006.
[49] IPCC, 2005; Rhudy, 2006; Smith et al, 2001.

Status of Worldwide Geologic Sequestration Projects

The chart below, from the 2005 IPCC Special Report on Carbon Dioxide Capture and Storage, outlines existing and planned worldwide projects in geologic storage of CO_2.[50] Highlights include:

- The Sleipner project in Norway which has, since 1996, successfully injected 7 million tons of CO_2 1,000 meters deep into the Utsira formation, a saline aquifer beneath the North Sea.[51] The carbon dioxide comes directly from Norwegian oil and gas company Statoil's Sleipner West natural gas production facility. About 1 million tons of carbon dioxide are injected annually into the aquifer, which has an estimated capacity of more than 600 billion tons of CO_2.[52]
- Initiated in 2001, the Weyburn enhanced oil recovery project in Saskatchewan, Canada is the longest running program in North America. The project has successfully sequestered 5 million tons of CO_2, with a projected maximum capacity of up to 30 million tons of CO_2.[53] As of fall 2005, there had been no indication of CO_2 leakage to the surface and near-surface environment.[54]
- The In Salah project in Algeria has been injecting up to 1.2 million tons of CO_2 per year since 2004. The CO_2 is stored in a sandstone reservoir 1800 meters deep. Over the life of the project, up to 17 million tons of CO_2 could be stored in the reservoir.[55]

[50] IPCC, 2005.
[51] IPCC, 2005.
[52] Demonstrating Carbon Sequestration.
[53] US DOE, 2005..
[54] White, 2005; Strutt et al., 2003, as referenced in IPCC, 2005.
[55] IPCC, 2005 and NETL, 2006.

Table 3: A Selection of Current and Planned Geological Storage Projects[56]

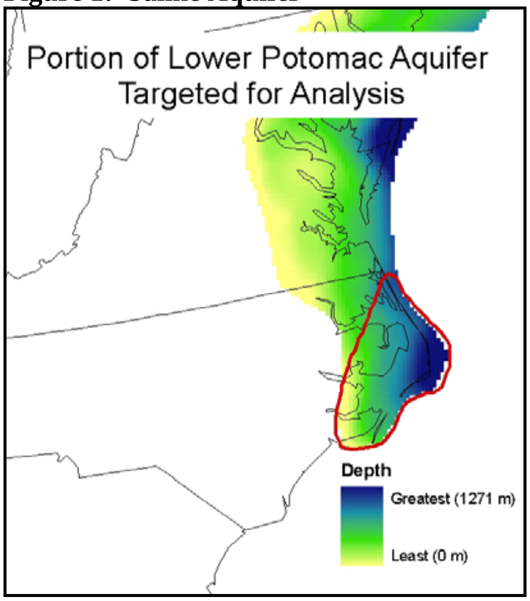
Project	Country	Scale of Project	Lead organizations	Injection start date	Approximate average daily injection rate	Total storage	Storage type	Geological storage formation	Age of formation	Lithology	Monitoring
Sleipner	Norway	Commercial	Statoil, IEA	1996	3000 t day^{-1}	20 Mt planned	Aquifer	Utsira Formation	Tertiary	Sandstone	4D seismic plus gravity
Weyburn	Canada	Commercial	EnCana, IEA	May 2000	3-5000 t day^{-1}	20 Mt planned	CO_2-EOR	Midale Formation	Mississippian	Carbonate	Comprehensive
Minami-Nagoaka	Japan	Demo	Research Institute of Innovative Technology for the Earth	2002	Max 40 t day^{-1}	10,000 t planned	Aquifer (Sth. Nagoaka Gas Field)	Haizume Formation	Pleistocene	Sandstone	Crosswell seismic + well monitoring
Yubari	Japan	Demo	Japanese Ministry of Economy, Trade and Industry	2004	10 t day^{-1}	200 t Planned	CO_2-ECBM	Yubari Formation (Ishikari Coal Basin)	Tertiary	Coal	Comprehensive
In Salah	Algeria	Commercial	Sonatrach, BP, Statoil	2004	3-4000 t day^{-1}	17 Mt planned	Depleted hydrocarbon reservoirs	Krechba Formation	Carboniferous	Sandstone	Planned comprehensive
Frio	USA	Pilot	Bureau of Economic Geology of the University of Texas	4-13 Oct. 2004	Approx. 177 t day^{-1} for 9 days	1600t	Saline formation	Frio Formation	Tertiary	Brine-bearing sandstone-shale	Comprehensive
K12B	Netherlands	Demo	Gaz de France	2004	100-1000 t day^{-1} (2006+)	Approx 8 Mt	EGR	Rotleigendes	Permian	Sandstone	Comprehensive
Fenn Big Valley	Canada	Pilot	Alberta Research Council	1998	50 t day^{-1}	200 t	CO_2-ECBM	Mannville Group	Cretaceous	Coal	P, T, flow
Recopol	Poland	Pilot	TNO-NITG (Netherlands)	2003	1 t day^{-1}	10 t	CO_2-ECBM	Silesian Basin	Carboniferous	Coal	
Qinshui Basin	China	Pilot	Alberta Research Council	2003	30 t day^{-1}	150 t	CO_2-ECBM	Shanxi Formation	Carboniferous-Permian	Coal	P, T, flow
Salt Creek	USA	Commercial	Anadarko	2004	5-6000 t day^{-1}	27 Mt	CO_2-EOR	Frontier	Cretaceous	Sandstone	Under development
Planned Projects (2005 onwards)											
Snøhvit	Norway	Decided Commercial	Statoil	2006	2000 t day^{-1}		Saline formation	Tubaen Formation	Lower Jurassic	Sandstone	Under development
Gorgon	Australia	Planned Commercial	Chevron	Planned 2009	Approx. 10,000 t day^{-1}		Saline formation	Dupuy Formation	Late Jurassic	Massive sandstone with shale seal	Under development
Ketzin	Germany	Demo	GFZ Potsdam	2006	100 t day^{-1}	60 kt	Saline formation	Stuttgart Formation	Triassic	Sandstone	Comprehensive
Otway	Australia	Pilot	CO2CRC	Planned late 2005	160 t day^{-1} for 2 years	0.1 Mt	Saline fm and depleted gas field	Waarre Formation	Cretaceous	Sandstone	Comprehensive
Teapot Dome	USA	Proposed Demo	RMOTC	Proposed 2006	170 t day^{-1} for 3 months	10 kt	Saline fm and CO_2-EOR	Tensleep and Red Peak Fm	Permian	Sandstone	Comprehensive
CSEMP	Canada	Pilot	Suncor Energy	2005	50 t day^{-1}	10 kt	CO_2-ECBM	Ardley Fm	Tertiary	Coal	Comprehensive
Pembina	Canada	Pilot	Penn West	2005	50 t day^{-1}	50 kt	CO_2-EOR	Cardium Fm	Cretaceous	Sandstone	Comprehensive

[56] IPCC, 2005.

GEOLOGIC CARBON STORAGE CAPACITY IN NORTH CAROLINA

North Carolina's geology is poorly suited for geologic carbon storage. Its eastern geomorphic province, the Coastal Plain, holds the only true potential. In this region, only one saline aquifer located in the Lower Potomac area was deemed appropriate for geologic carbon storage based on minimum acceptable depth of the aquifer.[57] See Figure 1.

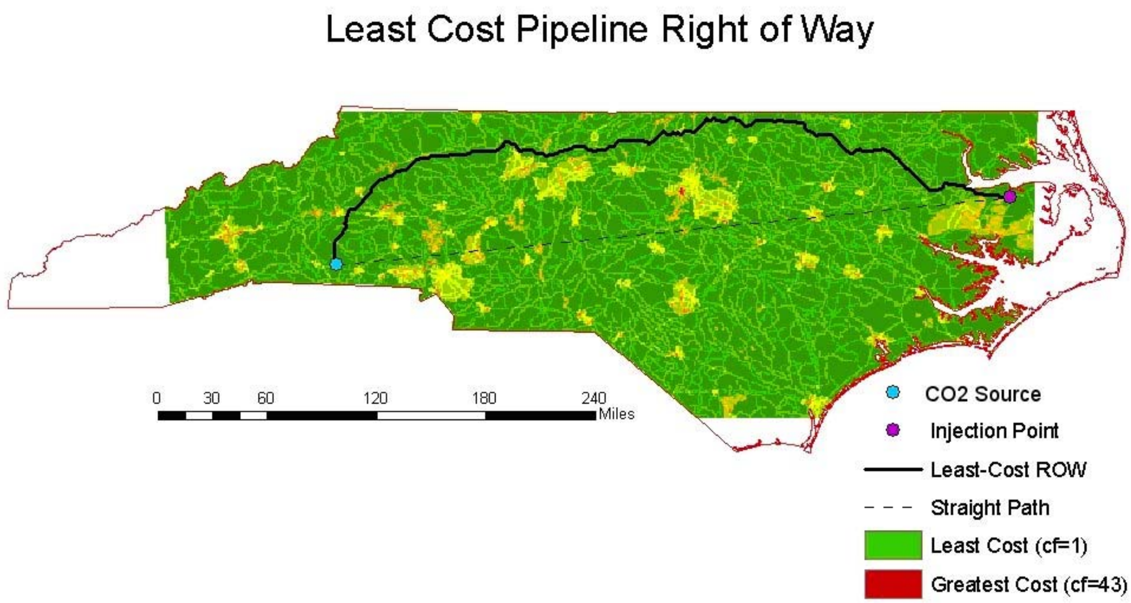
Figure 1: Saline Aquifer[58]



This geologic sink contains 29.91 $MMTCO_2$ of storage capacity, enough for three years of captured CO_2 emissions from around 1,600 MW of IGCC. Using spatial analysis tools, a least cost path was modeled across North Carolina from the assumed plant site to the hypothetical injection point in the saline aquifer. This path represents the optimal pipeline right of way that minimizes both distance and cost (Figure 2). This pipeline would cost around $0.5 billion, far too costly for only three years of storage.

[57] Hovorka, 2006.
[58] Greenglass, 2006.

Figure 2: North Carolina Pipeline to Saline Aquifer



Siting of the least cost pipeline right of way from the CO_2 source to the injection point. Also shown for comparison is the straight-line distance between the points. cf=cost factor.[59]

MULTI-STATE CO_2 PIPELINE OPTIONS

Although limited opportunity exists in North Carolina for geologic carbon sequestration, two strategies warrant further consideration:

1. Offset projects aimed at mitigating CO_2 emissions through biologic sequestration in agricultural soils and forests;
2. A dedicated pipeline for transporting CO_2 captured from electricity generation to viable geologic sinks in the Appalachian Basin and Gulf Coast regions, taking advantage of:
    a. cost reduction by pooling transportation and storage from a greater number of generation facilities;
    b. production of offsetting revenues from enhanced recovery of oil or coal bed methane.

Analysis of the construction of a multi-state pipeline to connect North Carolina electric utilities to geologic reservoirs in the Appalachian Basin and Gulf Coast regions is presented here.

Scenarios

We analyzed two basic scenarios: 1) 10,400 MW of SPC with a multi-state pipeline and CCS,[60] with additional capacity to make up for the de-rating that results from the capture equipment, and 2) 11,050 MW[61] of IGCC with a multi-state pipeline and CCS,[62] with additional capacity to make up for de-rating.

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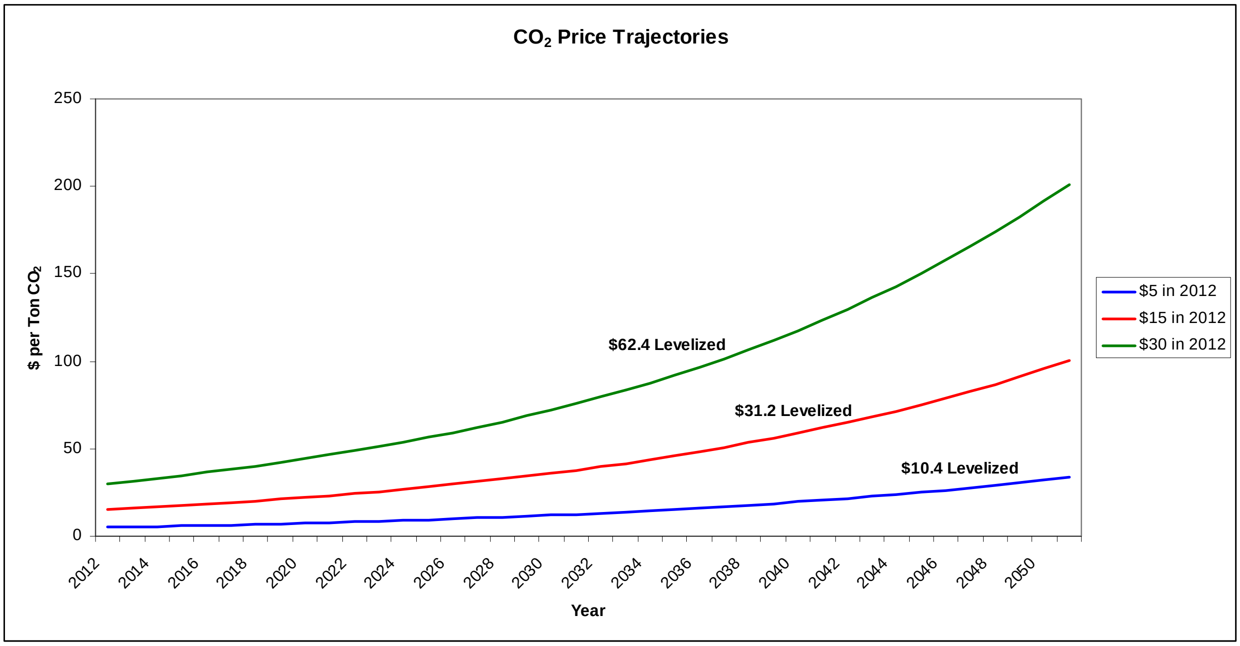
[59] Greenglass, 2006.
[60] The optimal year the CCS and pipeline come on-line varies according to the assumed CO2 price.
[61] We assumed that additional IGCC capacity is needed because it has a lower capacity factor than SPC; the two scenarios result in the same level of generation.

Assumptions

For each of the two general scenarios, we assumed that the SPC or IGCC plants would be built first. The CCS/pipeline system would be added later as it became cost-effective with a sufficiently high CO_2 price. The higher the CO_2 price, the sooner the CCS/pipeline system would be installed, and the lower the total CO_2 emissions – the sooner carbon is stored, the less is released to the atmosphere over the life of the plant. We analyzed a range of CO_2 prices from $0 to $30 per ton. For each CO_2 price, we assumed that it will escalate in real terms at a rate of 5% per year. See Figure 3. For example, a $15 per ton CO_2 price as reported in this paper begins at $15 in 2012, but grows to $95 per ton in 2050. That same price trajectory is equivalent to a flat or levelized price of $31 per ton over the same timeframe. For each CO_2 price and each plant technology, we found the optimal year to build the CCS/pipeline system.

Figure 3: CO_2 Price Trajectories



Our default SPC and IGCC cost and performance assumptions are presented in Table 4. Base plant costs and performance criteria are taken from the 2006 EPA report, *Environmental Footprints and Costs of Coal-Based. Integrated Gasification Combined Cycle and Pulverized Coal Technologies*. Capture costs and performance implications for base plants, as well as the methodology for adding make-up plants after de-rating, are derived from *Capture-Ready Power Plants – Options, Technologies and Economics* by Mark Bohm, MIT, 2006.

[62] The optimal year the CCS and pipeline come on-line varies according to the assumed CO2 price.

Table 4: Plant Cost and Operating Characteristics

Base Plant	IGCC	SPC
Capacity factor	80%	85%
Plant life	40	40
Heat rate	8,167	8,900
Overnight cost ($ per KW)	1,670	1,430
Fixed O&M ($/kWe/yr)	35.21	25.07
Variable O&M (mill$/kWh)	2.65	4.18
O&M real escalation rate per year	0.1%	0.1%
Capture Equipment		
Total overnight cost ($ per KW)	306	432
Capacity de-rating	19%	30%
Heat rate with capture	10052	12785
Fixed O&M with capture ($/kWe/yr)	41.44	33.00
Variable O&M with capture (mill$/kWh)	4.04	11.00
Implicit Total Capital Cost with Capture ($ per KW)	2363	2487

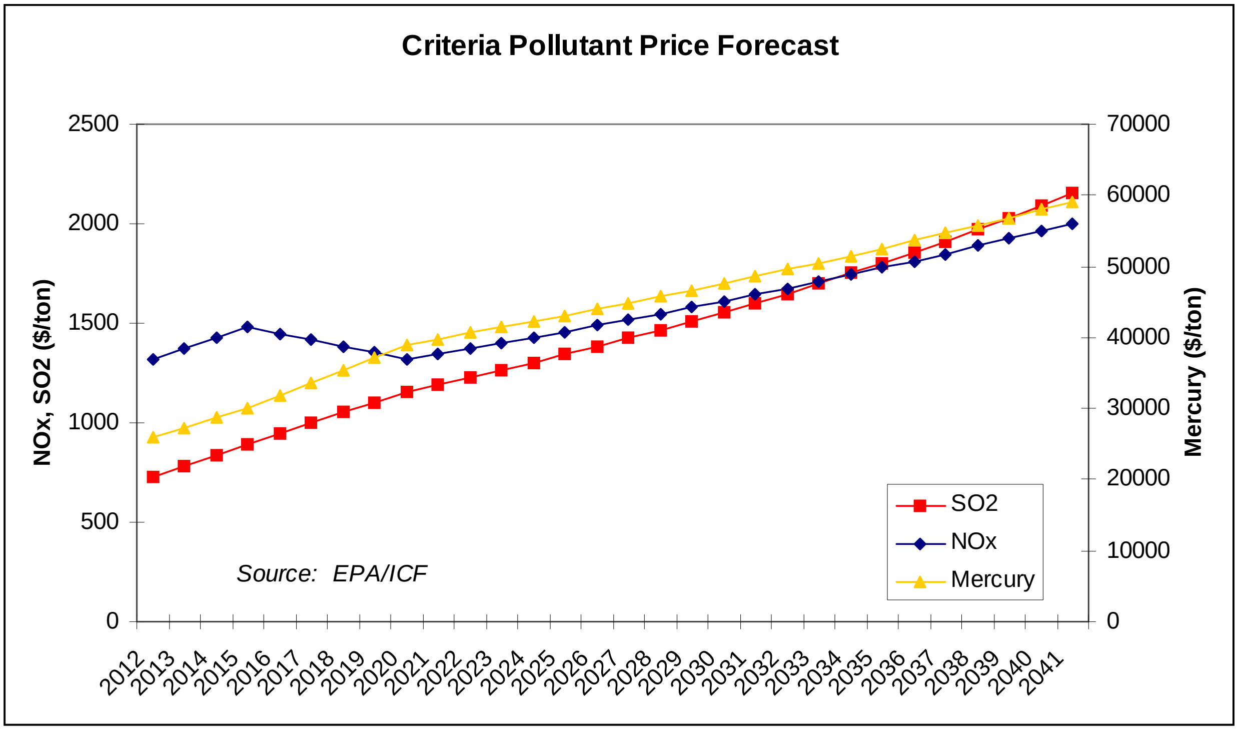
IGCC emits fewer tons of NOx, SO_2 and mercury than SPC (see Table 5). The full cost of criteria pollutants is included in the cost of SPC and IGCC based on EPA criteria pollutant price forecasts (Figure 4). We also used the southeastern regional fuel price forecast from the Energy Information Administration's Annual Energy Outlook 2006.

Table 5: Criteria Air Emissions[63]

	NOX rate (lb/MMBTU)	SO2 rate (lb/MMBTU)	Mercury rate (lbs/Trillion BTU)	NOX rate (lb/MWh)	SO2 rate (lb/MWh)	Mercury rate (lbs/kWh)
IGCC	0.020	0.018	0.379	0.150	0.133	0.003
PC	0.110	0.089	1.137	0.953	0.771	0.010

[63] Personal Communication, 2006 and Brickett, 2006

Figure 4: Criteria Air Pollutant Price Assumptions[64]



I. Construction of a multi-state pipeline

The Appalachian Basin and Gulf Coast regions contain robust geologic CO_2 reservoirs. A CO_2 pipeline linking North Carolina with these regions could be built along existing natural gas pipeline rights of way. Electricity-generating utilities outside North Carolina could also use this pipeline for CO_2 transport, and costs could be divided amongst participating utilities.

The Gulf Coast Region is an attractive site for geologic carbon sequestration because of the magnitude of potential geologic storage capacity, the existing knowledge of regional geology, and the technological infrastructure already in place from the petroleum and natural gas industries. Numerous depleted oil and gas reservoirs provide a known storage capacity for 2,500 $MMTCO_2$. Enhanced oil recovery in some areas is expected to add another 15% in storage capacity and can provide oil revenue to offset some costs associated with capture and storage. We did not assume any offsetting revenue from enhanced oil recovery in our analysis. Further, deep saline aquifers in the Gulf Coast region can provide additional and even larger geologic storage.[65]

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is preparing detailed estimates for storage capacity in the Appalachian Basin. Unmineable coal beds and depleted oil and gas reservoirs in this region are estimated to contain 25,000 $MMTCO_2$ and 2,000 $MMTCO_2$ storage capacity, respectively.[66] Extensive deep

[64] From EIA/ICF modeling of the CAIR rule.
[65] Ambrose et al, 2005.
[66] MRCSP, 2005.

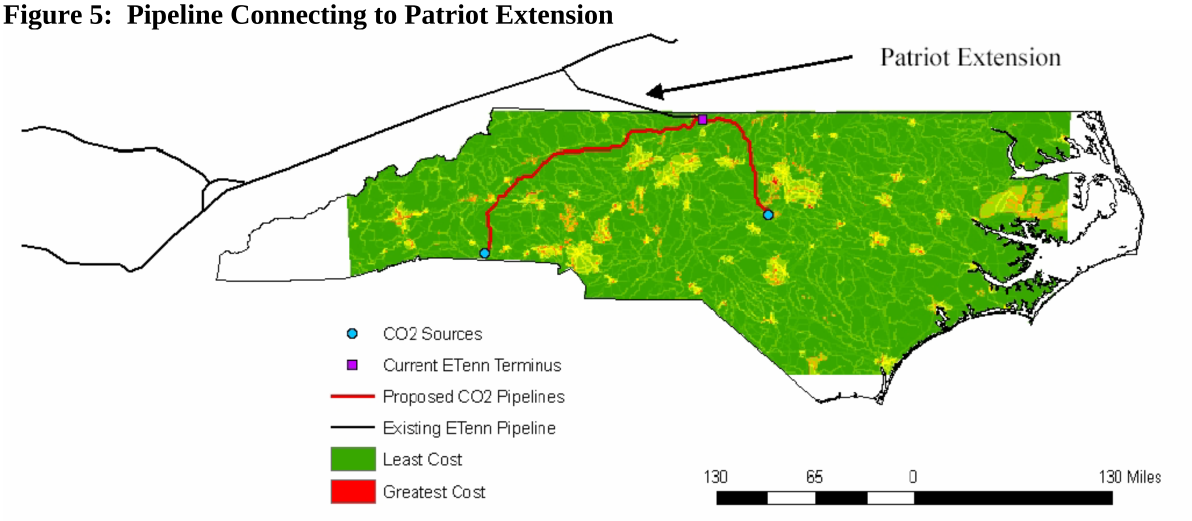
saline aquifers in this region may contain up to 500,000 $MMTCO_2$ of storage capacity.[67] However, concerns remain regarding groundwater contamination by CO_2.[68]

The largest available pipeline (36" diameter) could support a maximum CO_2 flow rate of 57 $MMTCO_2$/yr, which is sufficient to handle captured emissions from 11,050 MW of IGCC capacity. We did not assume any particular locations for the out-of-state capacity and made the simplifying assumption that total costs for feeder pipelines leading to the main pipeline from the other plants would be 5 times the cost of the feeder pipeline from the North Carolina plants.

The East Tennessee Pipeline extends to both geologic reservoir regions of interest (Figure 6) and connects to North Carolina via the Patriot Extension (Figure 5). We therefore evaluated the possibility of installing and connecting a dedicated pipeline that could transport CO_2 from North Carolina sites to the Patriot Extension. We performed a spatial analysis to calculate the least-cost paths, taking into account costs per mile associated with construction costs in populated areas, wetlands, and waterway, railroad, and highway crossings (see p. 10 for further explanation).

The least cost path distance from one North Carolina site to the Patriot Extension/East Tennessee terminus is approximately 275 miles with an installation cost of $193,793,764, while the least cost path distance from another North Carolina site to the pipeline terminus is 133 miles at a cost of $93,791,213 (Figure 6).

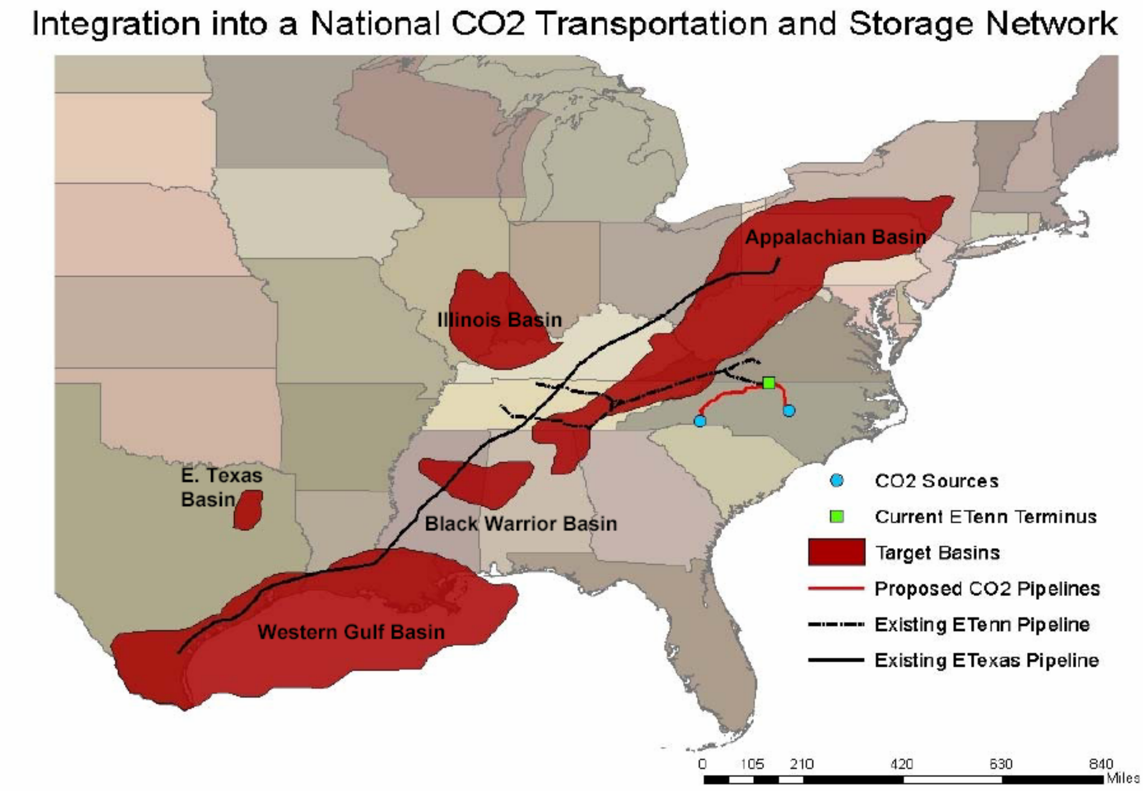
Figure 5: Pipeline Connecting to Patriot Extension



The Texas Eastern pipeline runs 9,040 miles from the Appalachian Basin to the Western Gulf Coast Basin. The Texas Eastern pipeline intersects the East Tennessee pipeline in Tennessee. A second CO_2 pipeline would need to be constructed along the East Tennessee right of way in order to connect North Carolina's utilities to the Texas Eastern pipeline allowing CO_2 to be piped to either of the targeted sequestration regions (Figure 6). A 1,730 mile segment of the Texas Eastern right of way would be sufficient for CO_2 transport to both the Appalachian Basin and the West Gulf Coast region, while a 523 mile length of the East Tennessee right of way would be required to connect the North Carolina pipelines to the Texas Eastern.

[67] MRCSP, 2005.
[68] Beecy and Kuuskraa, 2001.

Figure 6: Interstate Pipeline



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Based on this analysis, total pipeline capital costs would be approximately $5 billion. Annual pipeline and storage costs are shown in Table 6 and are based on a methodology described in Appendix A.

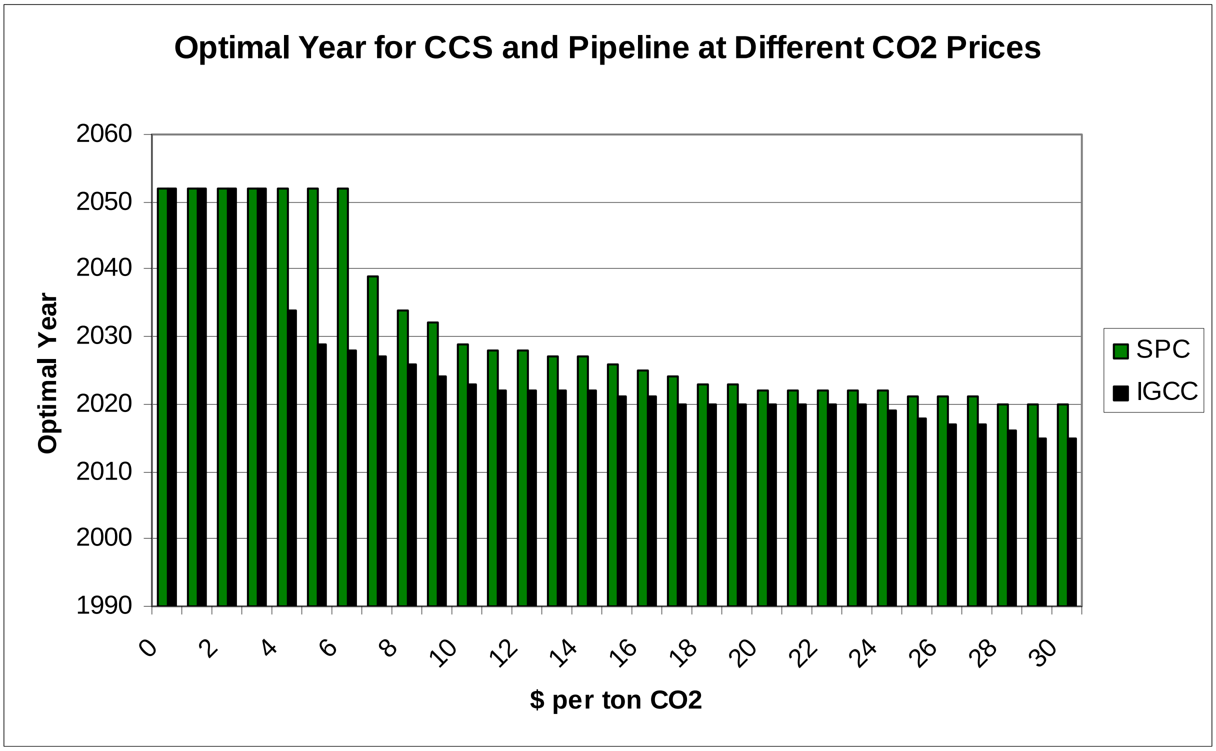
Table 6: Annual Pipeline and Storage Costs

Cost Categories	IGCC with CCS $ millions	SPC with CCS $ millions
Connector Pipeline Construction	224	224
East Tennessee (36") Pipeline Construction	98	98
Texas Eastern (36") Pipeline Construction	333	333
Well Capital Equipment	0.6	0.7
Well drilling	15	19
Storage Site evaluation	0.2	0.2
Pipeline O&M	11	11
Well O&M	16	20
TOTAL	699	707

Results

We analyzed a range of CO_2 prices, from $0 to $30 per ton ($0 to $62.40 levelized). For each CO_2 price, we found the optimal years to add CCS and build the pipeline and storage system for SPC and IGCC. See Figure 7. A CO_2 price of $29 per ton is needed to justify adding the CCS/ pipeline system by 2015 for IGCC; the same price justifies the CCS/pipeline system for SPC in 2020. A CO_2 price of at least $5 per ton in 2012 is needed to justify the investment of a CCS/pipeline system for IGCC any earlier than 2030. A CO_2 price of at least $11 is needed to invest in a CCS/pipeline system for SPC any earlier than 2030.

Figure 7: Optimal Years for CCS and Pipeline Investment



Because the CCS/pipeline system would come on-line at different times with different CO_2 prices, total emissions also varies with CO_2 price. The higher the price, the sooner the CCS/pipeline system comes on-line, and the lower the total emissions. See Figure 8. IGCC with CCS results in 8% to 55% lower emissions than SPC with CCS depending on the CO_2 price.

Figure 8: Total Lifetime CO_2 Emissions

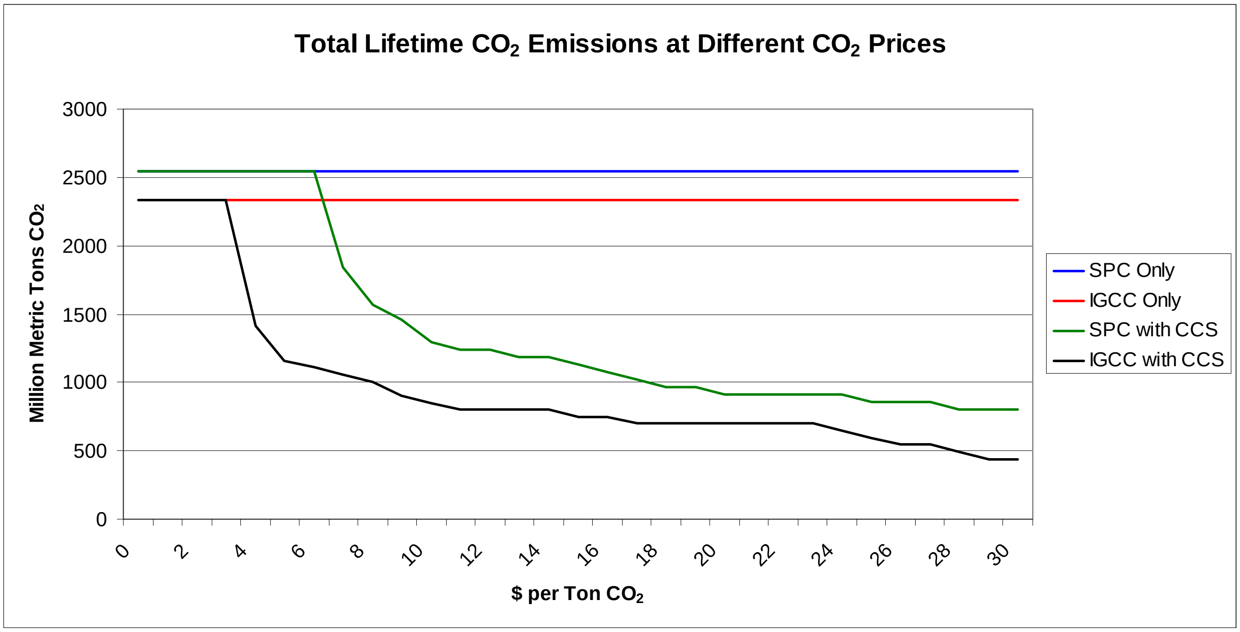
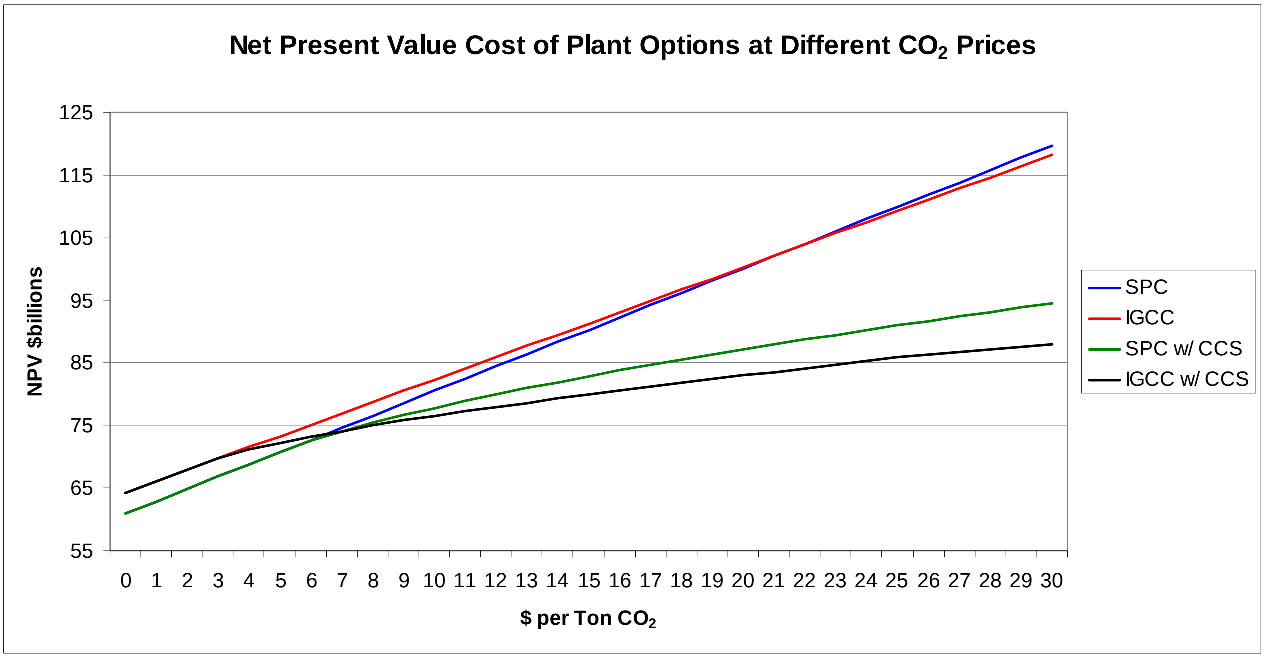


Figure 9 shows the net present value of the different coal technology options over a range of CO_2 prices. Below $7 per ton ($14.6 levelized), installing CCS and building a pipeline is never cost-effective; SPC has the lowest NPV cost in this range of CO_2 prices. Above around $7 per ton CO_2, the NPV cost of SPC can be lowered by investing in the CCS/pipeline system (the higher the price, the sooner the investment). Interestingly, at about the same price point, IGCC with the CCS/pipeline system becomes the option with the lowest NPV cost. The gap between the NPV cost of IGCC with the CCS/pipeline system increases with higher CO_2 prices.

If no carbon policy is implemented, and the price of CO_2 remains zero during the timeframe of the analysis, SPC would save $3.4 billion compared to IGCC. At $5 per ton ($10.4 levelized), SPC would save $1.6 billion. But at $10 per ton ($21 levelized), IGCC with CCS would save $1.3 billion compared to PC with CCS, and at $25 per ton ($52 levelized), IGCC with CCS would save $5.2 billion.

Figure 9: NPV Cost of Plant Options at Different CO_2 Prices



While post-combustion technology promises to lessen the risk of SPC in a carbon constrained world, IGCC with CCS fares better in this analysis than SPC at moderate to high CO2 prices. Many assumptions that were factored into this analysis are uncertain and could turn out to be different, leading to a different conclusion. For example, carbon policy and a carbon price may not come into play until much later than 2012. IGCC costs may turn out to be higher than expected. Post-combustion capture for SPC may also cost more than estimated. IGCC performance may be lower than expected.

Sensitivity Analysis

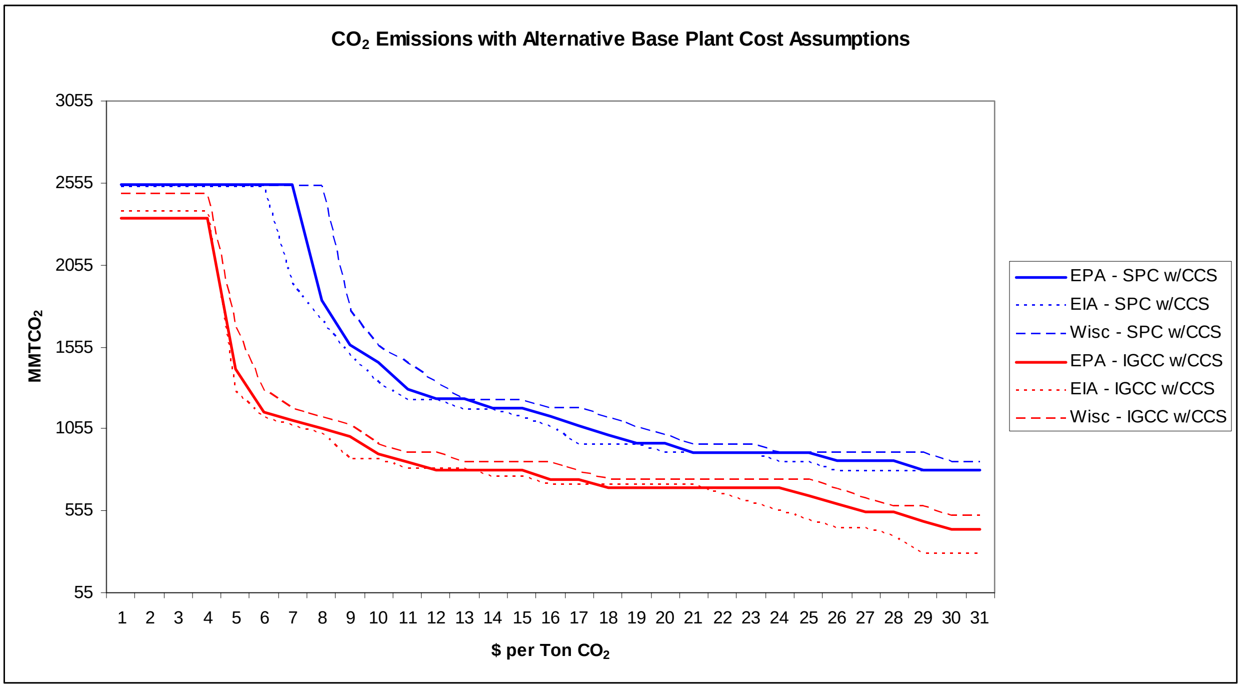
In order to provide some context for how results may change, we repeated the analysis with alternative base assumptions from the literature for cost and performance of SPC and IGCC. The Energy Information Administration publishes the Annual Energy Outlook, and in it are peer-reviewed cost and performance estimates for a variety of technologies including SPC and IGCC. We used these EIA assumptions as one alternative. The Public Service Commission of Wisconsin formed a Clean Coal Study Group to assess the cost and reliability of IGCC technology. The group released a report on its findings in August 2006. We used the Wisconsin assumptions for Eastern coal as another alternative. To put the default analysis in context, we included those results in this section as well.

One of the reasons we selected EPA assumptions as our default is that the cost and performance assumptions fall in the middle of the other two sets of assumptions. Not surprisingly, the results with EPA assumptions fall in the middle as well.

There are many other estimates of SPC and IGCC cost in the literature, though none is as recent or pertinent as the ones included here. The Electricity Policy Research Institute (EPRI) recently released a report evaluating SPC and IGCC options for a Texas utility. We decided not to include those estimates because the quality of the coal assumed in that analysis is significantly different than what would be used in North Carolina. As a result, the cost and performance of the technology designed specifically for the Western coal used in Texas would be quite different than the technology designed for Eastern coal used in North Carolina. Including the EPRI assumptions would lead to an apples-to-oranges comparison.

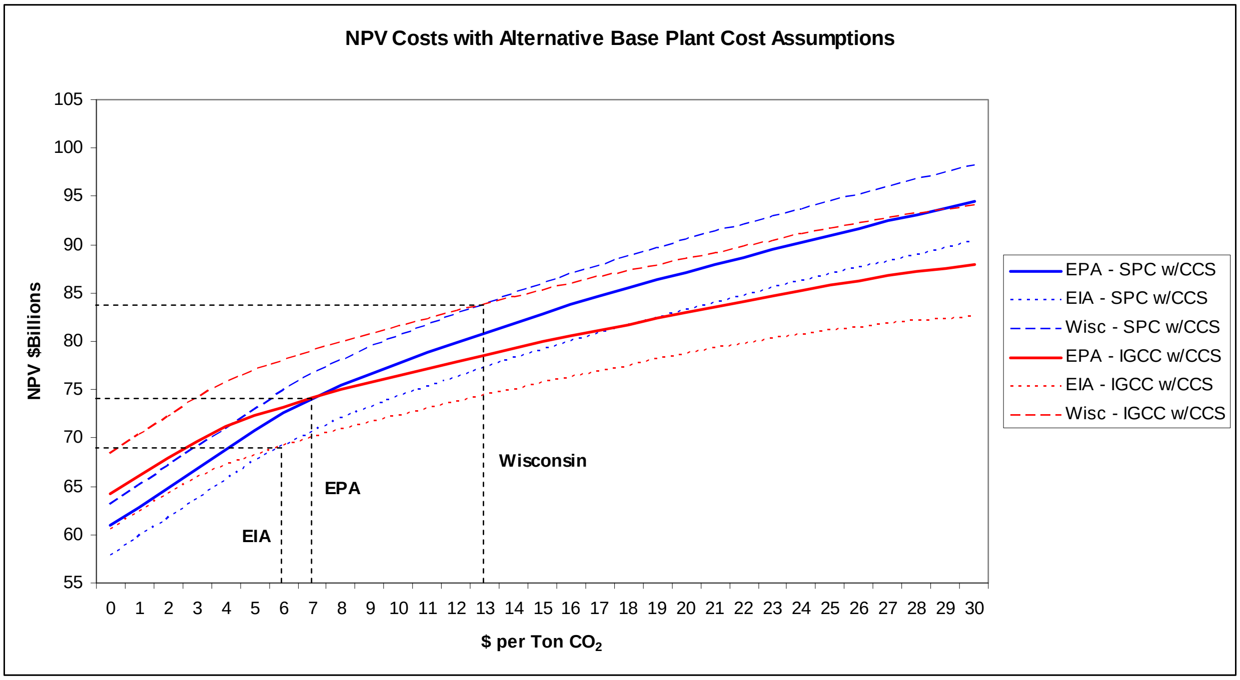
Timing of the CCS/pipeline system varies somewhat with alternative cost and performance assumptions and is primarily responsible for the differences in total CO_2 emissions shown in Figure 10. All the assumptions show CO_2 emissions from SPC within a narrow band. Differences are almost entirely the result of differences in optimal timing of the CCS/pipeline system. As a mature technology, this common agreement, which is directly related to similar assumptions regarding heat rate, is of little surprise. To the extent that timing of CCS is different, the assumptions differ in regard to cost. The assumptions show a wider range of CO_2 emissions for IGCC, which is also not surprising given the uncertainty around the performance of IGCC. The Wisconsin assumptions show CO_2 emissions from IGCC in the absence of CCS to be only slightly lower than emissions from SPC; however, as with the other assumptions, once CCS is installed, CO_2 emissions converge to a much tighter band in the middle CO_2 price range. At higher prices, when CCS is installed right away, the influence of differing heat rate assumptions for IGCC becomes greater again.

Figure 10: CO_2 Emissions with Alternative Base Plant Cost Assumptions



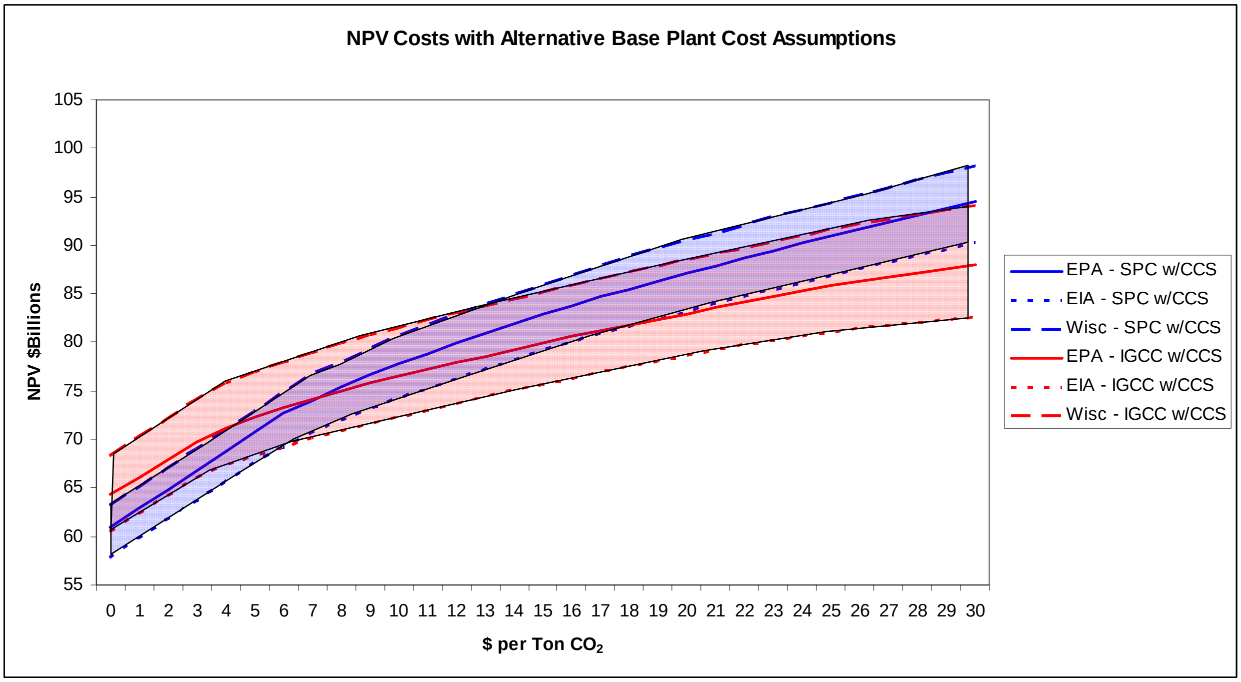
Each set of assumptions leads to a different crossover price of CO_2 in which the NPV cost of IGCC with CCS is lower than the NPV cost of SPC with CCS. See Figure 11. EIA numbers result in a $6 per ton CO_2 ($12.5 levelized) crossover price. The Wisconsin values result in a $13 per ton CO_2 ($27 levelized) crossover price. The default EPA assumptions lead to a $7 per ton CO_2 ($15 levelized) crossover price.

Figure 11: NPV Costs with Alternative Base Plant Cost Assumptions



The same results that were shown in Figure 11 are presented in Figure 12 in a different manner. In this figure, the IGCC NPV costs are shown as a shaded red area, with the Wisconsin results forming the upper bound and the EIA results forming the lower bound. The SPC NPV costs are presented in a similar fashion, but shaded blue. The extent to which there is overlap between the NPV costs of SPC and IGCC in this figure is informative. Although this is not a probability distribution and should not be interpreted as such, what is clear is that, in practice, there may be little expected difference in total costs between SPC and IGCC, especially in the middle range of CO_2 prices. From an economic perspective, the choice of building SPC or IGCC is depends largely on the expectation of future CO_2 prices. In a low CO_2 price world, SPC is likely the best bet. In a middle CO_2 price world, the choice may be a toss-up, but until IGCC technology is fully commercialized and technology risks reduced, investors may reasonably opt for SPC, though SPC capture technology is less certain than IGCC at this point. But in a high CO_2 price world, the optimum choice seems clearly to be IGCC despite the risks.

Figure 12: NPV Cost Overlap



CONCLUSIONS

Public and business support for mandatory climate policy continues to grow in the United States, making mandatory climate policy increasingly likely in coming years. Whether this policy adds CO_2 as a fourth air pollutant under a comprehensive cap and trade program for clean air (i.e., Carper Bill), or is an independent carbon tax or cap and trade program (i.e., Lieberman/McCain), the effect on cost of power generation could be significant. For utilities in the process of adding new generation capacity with 30-50 year life-spans, considering the potential costs of carbon and other greenhouse gas emissions becomes essential.

If the EU-ETS carbon market is a predicator of a future value in a US system ($20+/ton), cost-benefit ratios begin to shift significantly for commercial-scale introduction of new technology. While ultimate U.S. policy details and mechanisms remain uncertain, there is little debate regarding the potential economic value of carbon and greenhouse gas emission control in a carbon-constrained regulatory environment.

Coupling SPC or IGCC with CCS can substantially reduce CO_2 emissions from coal powered generation and reduce total costs with moderate to high CO_2 prices. Perhaps the most unexpected finding and possible opportunity for North Carolina utilities is the likely economic viability to capture CO_2 and transport it to the Gulf Coast or Appalachian Basin where there is abundant geological storage capacity, provided remaining technical barriers can be overcome and costs turn out to be as expected. Because IGCC with CCS promises the lowest emissions at the lowest cost (once the technology is fully commercial), targeted policies to assist utilities in building and operating IGCC plants is critical to overcoming hurdles presented by this nascent technology so that IGCC can be commercialized and its potential realized.

APPENDIX A

Capital costs associated with pipeline construction from sites in North Carolina to the East Tennessee pipeline right of way were based on the least-cost path determined by a geographical information systems (GIS) analysis. Pipeline costs starting at the East Tennessee pipeline right of way are assumed to equal basecase assumptions for cost per mile from Beck, 2006 (see Table 7 below).

Table 7: Basecase Pipeline Costs

Table 2: Pipeline Costs per Mile
Source: R.W. Beck, 2006

Pipeline Diameter (in)	Cost ($/mile)
16	704,000
20	910,000
24	1,104,000
30	1,305,000
36	1,584,000

Details of the GIS analysis can be found in Greenglass, N. (2006). Table 8 shows cost multipliers for various geographic features used in the GIS analysis to determine the least-cost route.

Table 8: Pipeline Cost Multipliers[69]

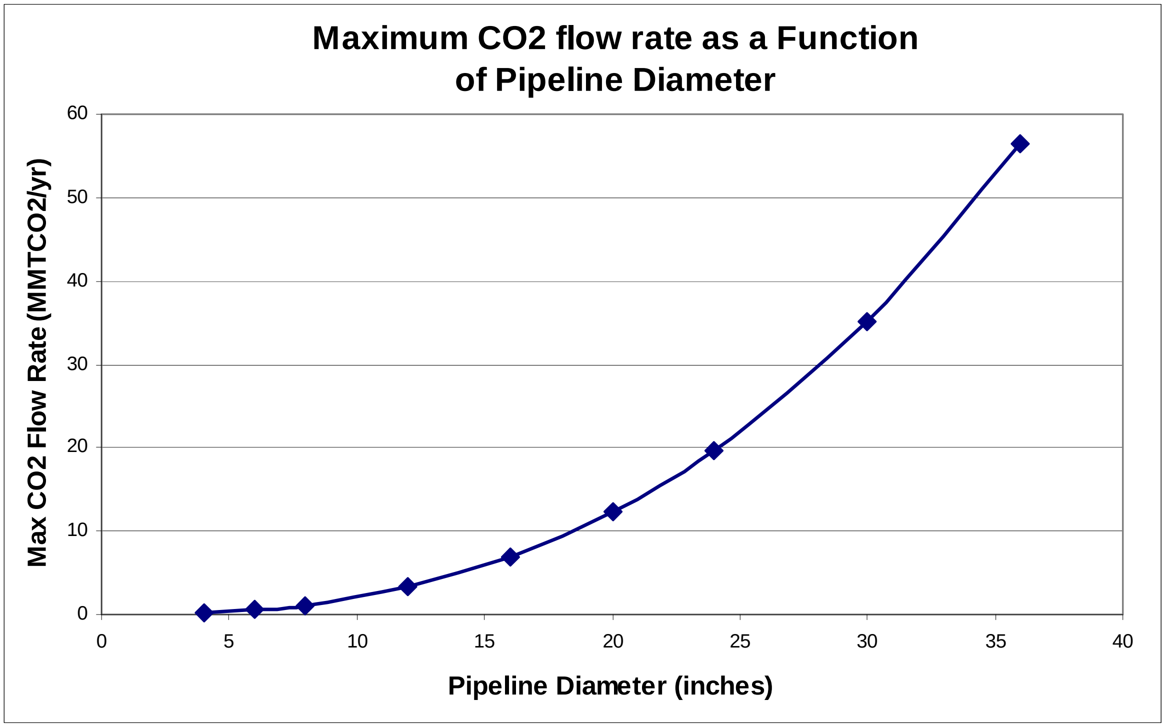
Pipeline Crossings

Construction Condition	Cost Factor
Base Case	1
Populated Area	15
Wetland	15
Waterway Crossing	10
Railroad Crossing	3
Highway Crossing	3

Diameter is the other major determinant of pipeline cost. Annual CO_2 flow is about 58 million tons CO_2, corresponding to a pipeline diameter of 36 inches (see Figure 13 below).[70]

[69] Herzog et al, 2006a
[70] For the Multistate scenarios, the connector pipelines leading from the IGCC plants to the main interstate pipeline are assumed to be 16 inches in diameter. The interstate pipeline for the Multistate 2400 scenario is 20 inches and for the Multistate 10400 is 36 inches.

Figure 13: Relationship Between CO_2 Flow Rate and Pipeline Diameter[71]



In addition to estimating pipeline costs, we also evaluated CO_2 storage costs based on methodology from EPRI (2002). (see Table 9 below). The first key input is the number of tons of CO_2 sequestered per day. Given the type of reservoir (saline aquifer or depleted oil well in these scenarios), the number of wells can be estimated. The number of wells then determines the cost of injection equipment, well drilling, and well O&M. Well drilling and subsurface maintenance costs are also a function of well depth. Site evaluation also adds an additional $1.7 million.

Table 9: CO_2 Storage Methodology

Storage Components	Formulas
Injection Equipment	43600*(7389/(280*# of wells))^0.5
Well drilling	0.0888e^(0.0008*Well-depth)* $1,000,000 * # of wells
Well O&M Cost per Year	
Daily	6700*# of wells
Consumables	17900*# of wells
Surface maintenance	13600*(7389/(280*# of wells))^0.5
Subsurface maintenance	5000*well depth/1219
CO_2 monitoring	Tons CO_2*0.1
# of Wells	
Depleted Oil	360 tons CO2/day/Well
Aquifer	9363 tons CO2/day/Well

[71] Herzon et al, 2006a

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