REPORT

OptimaCCS Carbon Capture and Storage Infrastructure Optimization

North Carolina Case Study

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EXECUTIVE SUMMARY

In 2001, the Intergovernmental Panel on Climate Change (IPCC) concluded that greenhouse gases (GHGs) are the major contributor to global climate change. While coal is the most abundant domestic resource, it is also the most GHG-intensive energy source. In North Carolina, 14 of the 15 largest sources of GHGs emissions are coal-fired power plants—producing in excess of 65 million tons of carbon dioxide equivalent (CO_2e) in 2010 (U.S. EPA 2012). Addressing these emissions is essential for the proper utilization of the coal resource and the reduction of GHGs.

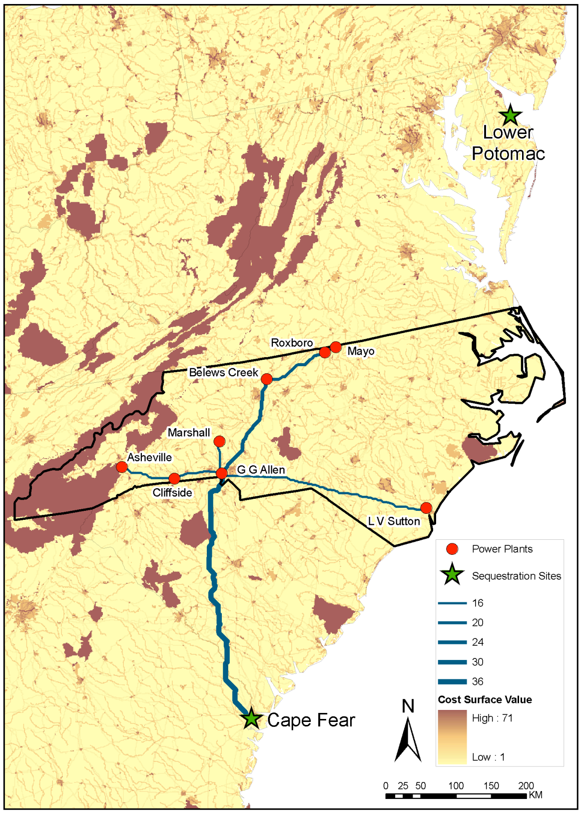
The use of carbon capture and storage (CCS) in the United States could allow coal-fired power generation to remain a major component of the nation's energy mix by reducing its carbon emissions. The cost of capturing carbon dioxide (CO_2) will affect the deployment of CCS, as will the costs of CO_2 pipeline transport and underground injection. The latter can increase CCS costs by \$2–\$100 per ton of CO_2, depending on the locations of coal plants relative to storage sites, the quantity of captured CO_2, and the rate that it can be pumped underground. Transportation and storage costs can be minimized, however, by optimizing the design of the CO_2 transport system.

Duke University has developed software for this purpose. OptimaCCS maps out cost-efficient options for overall CCS network design, including pipeline routes, necessary pipe diameters and lengths, efficiencies from using shared pipelines, and the impact of sequestration costs. In a previous whitepaper, researchers applied OptimaCCS to evaluate the costs and design of a CCS system within Texas. In this second state-specific whitepaper, we perform a similar analysis focusing on coal-fired power plants in North Carolina. Unlike Texas, North Carolina does not have cost-effective onshore options for storing CO_2 emissions in geologic formations. If storage is limited to onshore options, a pipeline system that transports CO_2 to out-of-state reservoirs would be required to make CCS projects in North Carolina economically feasible.

Figure ES-1 below illustrates the results produced by OptimaCCS. Both illustrations (a and b) show cost-efficient designs for CCS networks that connect existing coal plants to potential storage sites in the Lower Potomac (Delaware) and Cape Fear (South Carolina) basins. In this illustration, the cost of injection is lowest at the Lower Potomac storage site. The network on the left (a) is the result when injection costs are ignored; the network on the right (b) is the result when injection costs are accounted for.

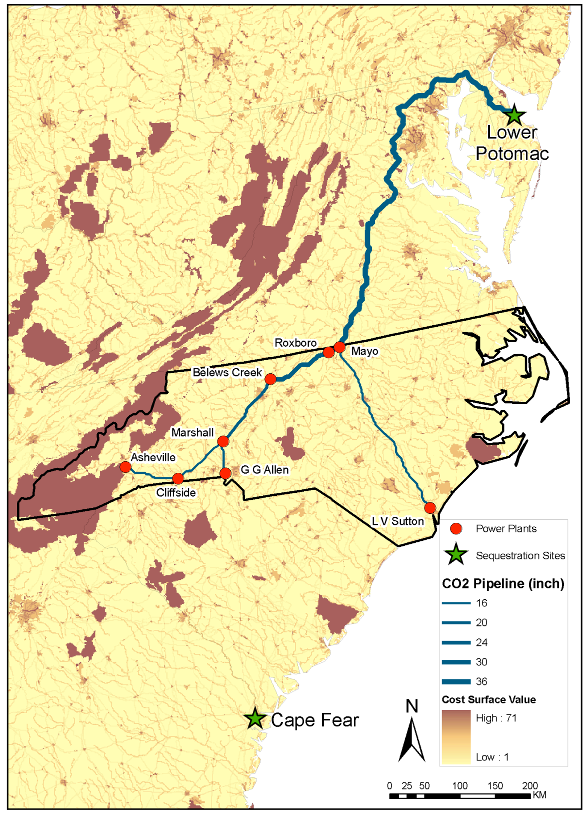
Figure ES-1:OptimaCCS results

a. Injection costs ignored



No.	Characteristics	Values
1	Distance (km)	1,185
2	Largest pipe size (inches)	36
3	Pipeline and compressor cost (million $)	$1,367
4	Injection cost (million $)	$3,243
5	**Total cost (million $)**	**$4,610**

b. Injection costs accounted for



No.	Characteristics	Values
1	Distance (km)	1,366
2	Largest pipe size (inches)	36
3	Pipeline and compressor cost (million $)	$1,778
4	Injection cost (million $)	$580
5	**Total cost (million $)**	**$2,358**

The associated tables summarize the key characteristics of the two CCS networks. Note that by considering injection costs in the design of the CCS network, overall costs are reduced by $2.3 billion. This highlights the gains in systematic planning for CCS infrastructure achievable using OptimaCCS.

1. INTRODUCTION

The Intergovernmental Panel on Climate Change (IPCC) in 2001 concluded that a significant reduction in GHG emissions would be necessary to reach climate stabilization. If North Carolina is going to reduce GHG emissions, all viable options for reduction within the state must be explored. As the largest contributor to North Carolina emissions at 41%, the electricity sector must play a critical role (Williams et al. 2007). Because coal dominates electricity-sector emissions in North Carolina, any credible GHG reduction strategy must address current coal use. One way to reduce carbon emissions from coal is to capture and store carbon emissions in geologic reservoirs. Collectively, these technologies are referred to as carbon capture and storage (CCS).

A CCS system consists of three major elements:

- technology to capture emissions at industrial sites and power plants;
- a pipeline network to transport carbon from the source to the storage sites; and
- geologic sinks to store carbon safely.

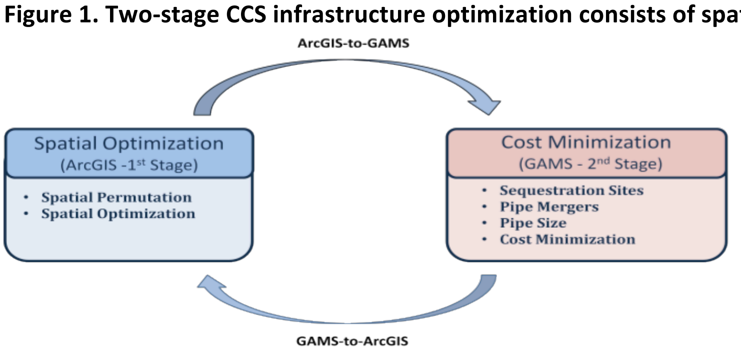
A major hurdle to the deployment of CCS is its high cost. The cost of capturing carbon depends on a number of factors, including how the plant generates power, what type of fuel is used, the plant's capacity, the capture technology implemented, and how much CO_2 is captured. Transportation and injection costs are highly variable and are determined by the spatial arrangement of the plants, the quantity of CO_2 to be transported, the location of sequestration sites, injection costs at these sites, and the level of cooperation among power plant operators.

A comprehensive system design—one that it is optimized based on all of the major factors that affect a CCS system—can significantly reduce the overall cost of the system (Middleton and Bielicki 2009). Researchers at Duke University's Nicholas Institute for Environmental Policy Solutions and Nicholas School of the Environment developed a spatial economic model, OptimaCCS, which minimizes CCS pipeline construction and injection costs by considering

- the most cost-effective CCS pipeline network design for transporting and injecting CO_2;
- site-specific costs associated with CO_2 transportation and injection;
- possible cost reductions from collaboration on pipeline construction by power plant operators; and
- the relationships between site-specific injection costs and the resultant CCS infrastructure.

OptimaCCS evaluates all of these decisions simultaneously by combining the spatial optimization capabilities of ArcGIS with the cost minimization capabilities of GAMS, a mathematical optimization program (Figure 1).

Figure 1. Two-stage CCS infrastructure optimization consists of spatial optimization and cost minimization



By integrating the spatial and mathematical optimization, OptimaCCS identifies the most cost-effective design for CCS infrastructure, one that leverages economies of scale by aggregating the flow of CO_2 from power plant point sources into a trunk pipeline that feeds one or more CO_2 sequestration sites.

2. NORTH CAROLINA CASE STUDY

2.1. Deployment scenarios

We demonstrate OptimaCCS using a set of coal-fired power plants and candidate sequestration sites in North Carolina. We calculate the costs of two scenarios: one in which storage is ignored, and one in which storage is considered. We also analyze different injection cost scenarios to assess how they affect the spatial arrangement of CCS infrastructure.

2.2. Power plants

The power plants in this example were selected using the Nicholas Institute's version of the U.S. Energy Information Agency's National Energy Modeling System, denoted as NI-NEMS. NI-NEMS identifies coal-fired power plants that would retrofit for carbon capture, based on an algorithm developed by the National Energy Technology Laboratory. This algorithm evaluates tradeoffs between retrofitting, retiring, and purchasing emission allowances.

Similar to the December 2011 Texas case study, we use the American Power Act (APA) (Kerry and Lieberman 2010) as the framework for our analysis, assuming the federal government provides \$95/ton[1] of captured CO_2, and that the initial price of CO_2 is \$20/ton starting in 2013. This price then undergoes an annual increase of 5%, as assumed in the U.S. Environmental Protection Agency's (EPA) analysis of the APA (U.S. EPA 2010). Based on these assumptions, NI-NEMS identified 8 existing coal-fired power plants as potential retrofit candidates. These are listed in Table 1, along with the amount of CO_2 that would be captured at each plant.

Table 1. Coal-fired power plants in North Carolina identified by NI-NEMS as having CCS potential

Plant name	Operator	County	Capacity (GW)	Emissions (Mt CO_2/year)	Captured (Mt CO_2/year)
Marshall	Duke Energy Corp.	Catawba	2.00	0.40	3.58
Roxboro	Progress Energy Carolinas Inc.	Person	3.30	040	3.58
G.G. Alan	Duke Energy Corp.	Gaston	1.15	0.18	1.59
Mayo	Progress Energy Carolinas Inc.	Person	0.73	0.41	3.68
Belews Creek	Duke Energy Corp.	Stoke	2.16	0.73	6.56
L.V. Sutton	Progress Energy Carolinas Inc.	New Hanover	0.67	0.29	2.59
Cliffside	Duke Energy Corp.	Cleveland	0.78	0.36	3.25
Asheville	Progress Energy Carolinas Inc.	Buncombe	0.41	0.13	1.20
	Total			**2.89**	**26.04**

The locations of the plants are shown in Figure 2. Together, the power plants have a combined capacity of 11.2 gigawatts (GW) and the potential to capture 26.04 Mt CO_2/yr.

2.3. Saline aquifers

National assessments of geologic reservoirs for storing CO_2 reveal that there is little in terms of viable onshore storage capacity in North Carolina. A new pipeline would be required to transport the CO_2 to out-of-state reservoirs if CCS were implemented in North Carolina. The two nearest potential saline aquifers

[1] The term *ton* (abbreviated *t*) in this paper refers to the metric ton (1,000 kg). The abbreviation *Mt* refers to the megaton (1 million tons).

are the Lower Potomac basin (Delaware) and the Cape Fear basin (South Carolina) (Figure 2). In characterizing these and 10 other such saline aquifers, Eccles et al. (2009) arrived at the estimates for capacity, average injection rate, and average CO_2 injection cost given in Table 2. Note that according to these estimates, the average injection cost at Lower Potomac is six times less than at Cape Fear.

Table 2. Average marginal CO_2 injection cost estimate

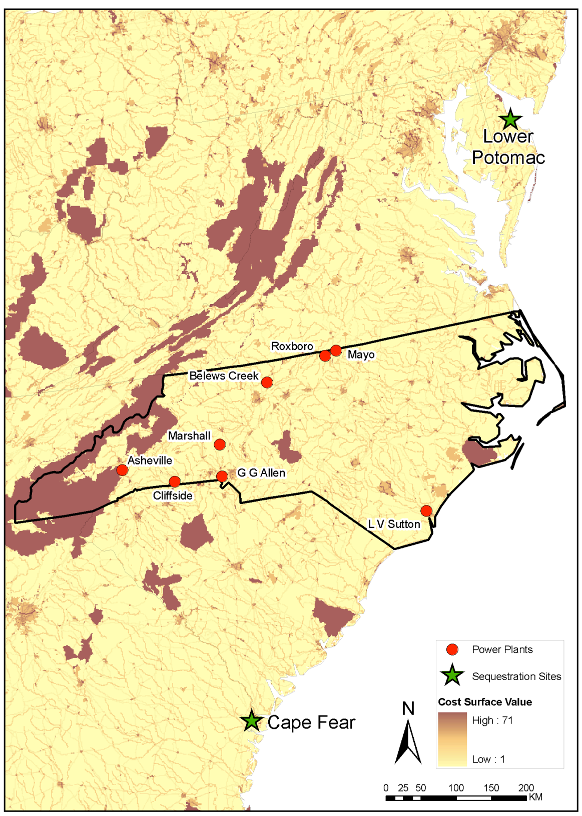
Saline aquifers	Avg. marginal injection cost ($/ton)
Lower Potomac	$0.74/ton
Cape Fear	$4.15/ton

Source: Eccles et al. 2009.

2.4. Cost surface

A cost surface developed at Massachusetts Institute of Technology (MIT) (Herzog et al. 2007) is utilized to represent the relative cost of constructing a pipeline through various types of terrain by considering both the geographical features as well as social and political data (Figure 3). The cost surface is a raster layer of the continental United States with a cell size of 1 km^2. The cell values are multipliers of an assumed baseline pipeline cost. This baseline pipeline cost (cost multiplier of 1) is for a pipeline that traverses a flat surface (without any obstacles) and includes fixed material, labor, and miscellaneous costs. The multiplier adjusts cost by factoring in the contribution of land slope, protected areas, and crossings of three line-type obstacles (waterways, railroads, and highways) (Herzog et al. 2007).

Figure 3. Map of candidate power plants identified by NI-NEMS and two saline aquifers with significant storage potential

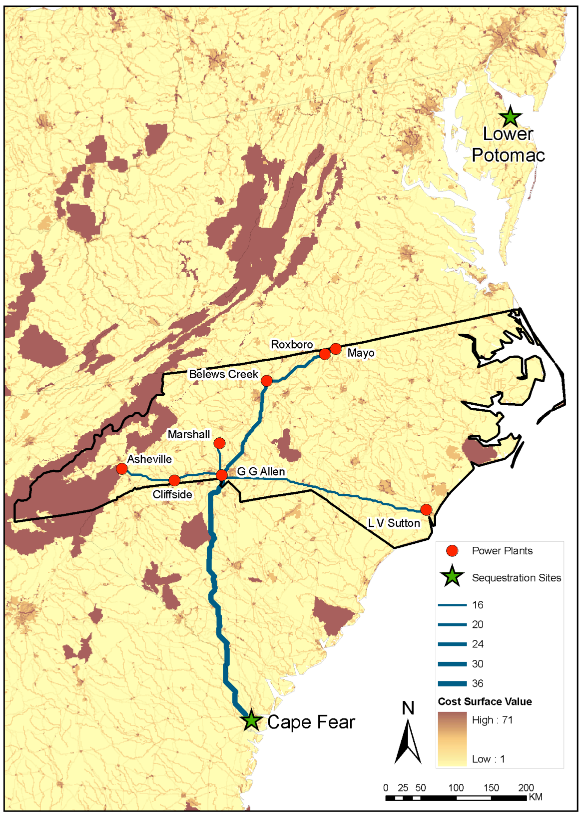


3. RESULTS

3.1. Scenario 1 – Injection costs ignored

Scenario 1 assumes storage costs are uniform among the three saline aquifers and thus not a factor in pipeline optimization. Only pipeline construction and transport costs are considered. This is similar to the analysis conducted by Herzog et al. (Herzog et al. 2007) for the West Coast Regional Carbon Sequestration Partnership (WESTCARB). However, we go a step further by allowing for pipeline convergence. This is done in OptimaCCS by identifying every pipeline segment as a potential hub for merging pipelines. Downstream of these mergers, greater efficiencies, and thus lower transport costs, are achieved by using larger pipelines appropriately sized to handle the merged flux of CO_2 emissions. In this example, such convergence occurs at the G.G. Allen power plant in Figure 3.

Figure 4. Optimal pipeline network assuming uniform storage costs



Under Scenario 1, Optima CCS connects each of the 8 power plants to the Cape Fear sequestration site (Figure 4). Because in this scenario we assume injection costs are equal among the sequestration sites, the pipelines are routed to the nearest sequestration site to minimize pipeline construction costs. The captured CO_2 from 8 power plants totals 26.04 Mt CO_2/yr and is moved through a network of 1,185 km of pipeline that would cost $1.37 billion to build (Table 3).

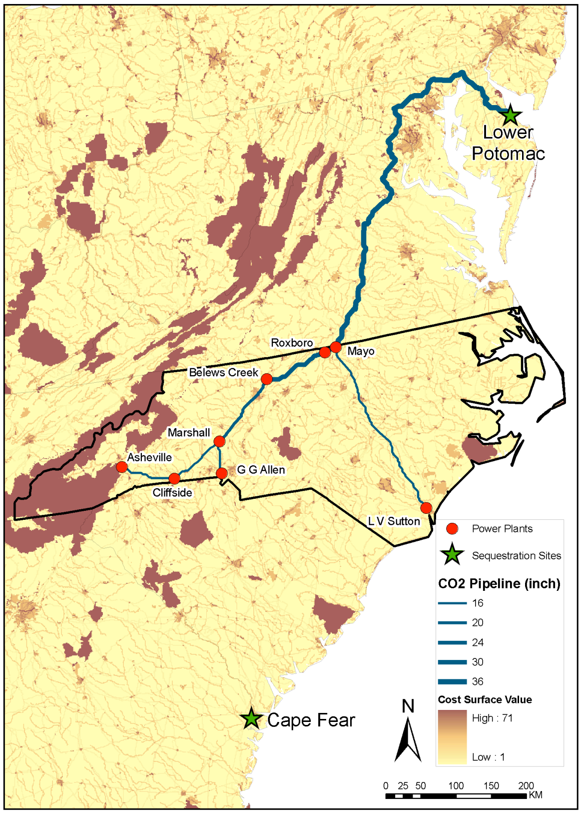
Table 3. Optimal network costs assuming uniform storage costs

Characteristics	Scenario 1
Distance (km)	1,185
Largest pipe size (inches)	36
Pipeline and compressor cost (million $)	$1,367
Injection cost (million $)	$3,243
Total cost (million $)	**$4,610**

3.2. Scenario 2 – Varying injection costs considered

Scenario 2 includes the different costs of storing CO_2 at the two saline aquifers as estimated by Eccles et al. (Table 3). Consequently, OptimaCCS analyzes the design of CCS infrastructure to minimize both pipeline and injection costs. The resulting pipeline network converges at the northernmost power plant, Mayo, and continues northward to the cheaper Lower Potomac sequestration site (Figure 5).

Figure 5. Optimal pipeline network assuming varying storage costs



Scenario 2 demonstrates that the more significant cost in the design of CCS pipeline networks is the storage cost. Table 4 compares the characteristics of the pipeline networks solved for under Scenario 1 and Scenario 2. Total pipeline lengths and costs in Scenario 2 are greater than in Scenario 1. However, when the different injection costs are also factored into Scenario 1, the storage cost for the first scenario ends up being six times more expensive than under Scenario 2. As a result, the overall cost of Scenario 2 ends up being almost half that of Scenario 1. So although the overall distance of the pipeline network is longer in Scenario 2 (1,366 km vs. 1,185 km) and pipeline construction costs are higher ($1,778 million vs. $1,367 million), the cheaper injection cost at Lower Potomac outweighs these factors, making the site a more economic sequestration option.

Table 4. Optimal network costs assuming varying storage costs

Characteristics	Scenario 1	Scenario 2
Distance (km)	1,185	1,366
Largest pipe size (inches)	36	36
Pipeline and compressor cost (million $)	$1,367	$1,778
Injection cost (million $)	$3,243	$580
Total cost (million $)	**$4,610**	**$2,358**

3.3. Varying injection costs and sensitivity

The outcome of the comprehensive optimization depends heavily on site-specific injection costs (Eccles et al. 2009), which may shift due to site-specific factors not considered here (e.g., more granular geologic data revealing storage is in fact more expensive at Lower Potomac than at Cape Fear, higher well-drilling costs). Additionally, the outcomes of comprehensive optimization do not lend themselves to a straightforward understanding of the relationship between site-specific injection cost and the infrastructure costs that would be required at a sequestration site.

With these shortcomings in mind, we progressively lower the relative difference in injection costs between the Lower Potomac and Cape Fear sequestration sites to establish the storage cost difference needed to shift the resultant CCS infrastructure from Lower Potomac to back to the nearer Cape Fear location. We find these relative costs must fall below \$1.27/Mt CO_2 (Table 4).

Table 4. Relative difference of marginal injection costs to Lower Potomac baseline cost with Lower Potomac serving as a single sequestration site

No.	Saline aquifers	Avg. marginal injection cost (\$/ton)
1	Lower Potomac	Baseline
2	Cape Fear	Baseline + \$1.27/ton

This analysis eliminates the dependence of the results on absolute values for injection costs, which are hard to constrain, and replaces them with an emphasis on marginal costs of injection.

4. CONCLUSION

Through our case study in North Carolina, we demonstrate that OptimaCCS can offer cost-effective designs for deploying CCS infrastructure under a range of spatial and economic constraints. Key points illustrated by this demonstration:

- While transport costs are significant, injection costs over the lifetime of the CCS system are likely to be even more significant—and thus bear a greater influence on the design of a CO_2 pipeline network—than the distances between CO_2 sources and storage sites.
- The greatest cost savings are achieved when the design of the pipeline network considers both transport and storage constraints.
- Current assessments indicate North Carolina has limited onshore capacity for storing CO_2 in saline aquifers. To employ CCS project in North Carolina, the captured CO_2 has to be transported to either Lower Potomac (Delaware) or Cape Fear (South Carolina).
- Currently injection costs at Cape Fear are \$3.40/Mt CO_2 more expensive than at Lower Potomac, making Cape Fear less economical for plant operators in North Carolina. Reducing this differential to ≤\$1.27/Mt CO_2 through technological innovation would make Cape Fear the optimal sequestration site.

Our illustration of OptimaCCS assumes all CCS infrastructures are deployed simultaneously, so these are best-case scenarios in terms of cost. Expenses will rise as infrastructure is deployed piecemeal over time. We are developing the ability to increment CO_2 capture retrofits as they occur and to determine the correct sequence of segmented infrastructure expansions for economic efficiency.

The scenarios in our case study show that comprehensive optimization yields a potential cost savings of roughly \$2.3 billion and highlights the importance of systematic planning for CCS infrastructure at different levels of cooperation between CO_2 sources and storage sites.

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