INTEGRATED CCS PRE-FEASIBILITY STUDY FOR WESTERN NEBRASKA

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INTRODUCTION

In collaboration with the Nebraska Public Power District (NPPD), the Energy & Environmental Research Center (EERC) has conducted a pre-feasibility study for a commercial-scale carbon dioxide (CO_2) geologic storage complex in western Nebraska, integrated with potential CO_2 capture at Gerald Gentleman Station (GGS). GGS is the largest coal-fired electricity-generating station in Nebraska, emitting 8.5 million tonnes (Mt) of CO_2 annually, and is located near the town of Sutherland. This pre-feasibility ("Phase 1") project has been executed as part of the U.S. Department of Energy (DOE) CarbonSAFE Program, where projects are required to demonstrate the potential to capture and store at least 50 Mt of CO_2 over a 25-year operational period.

The EERC and NPPD established a coordination team to address identified challenges to a potential Nebraska carbon capture and storage (CCS) project, drawn from local stakeholder organizations including regulatory agencies and industry. The coordination team met twice in Lincoln and via several Webinars, providing feedback and guidance throughout the pre-feasibility study.

The pre-feasibility assessment comprised three main technical themes, all using published information sources.

REGIONAL AND STAKEHOLDER ANALYSIS

A review of geographic and socioeconomic characteristics identified a five-county area around and to the southwest of GGS as the focus of project assessment (Figure 1).

A public outreach plan was developed for implementation in any further phases of CCS assessment in western Nebraska, for example a CarbonSAFE Phase 2 feasibility study.

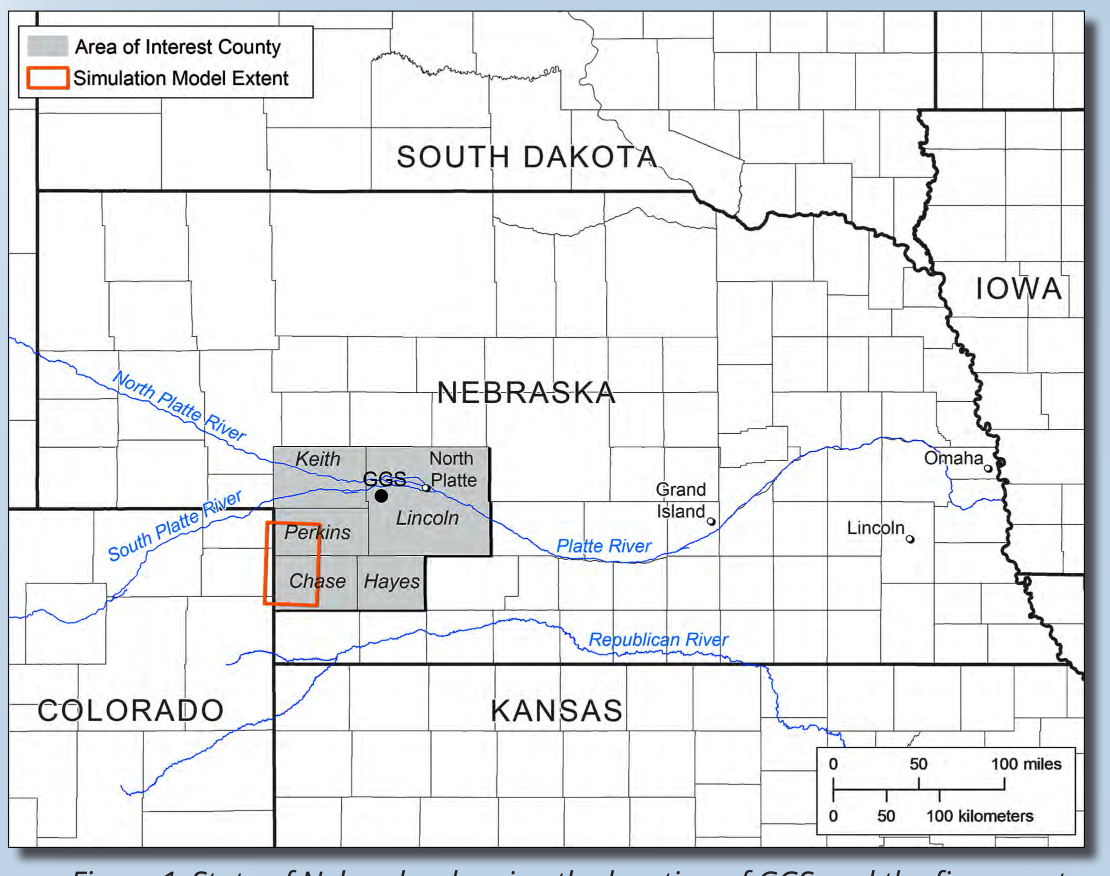

Figure 1. State of Nebraska showing the location of GGS and the five-county study area as well as the region of further geologic evaluation (orange rectangle).

SCENARIO ANALYSIS

GGS is the only single major source of CO_2 emissions capable of satisfying the CarbonSAFE 50-Mt-scale requirement within the study region. Chemical absorption using amines was identified as the most viable technology for postcombustion CO_2 capture at GGS. The total cost of a CCS project at GGS Unit 2 (GGS2) was estimated for a variety of capture scenarios (Table 1, Figure 2), using the Carnegie-Mellon University Integrated Environmental Control Model (IECM). The total avoided cost of a CCS project was estimated as $70/tonne and included the capture facility and parasitic load, a flue gas desulfurization (FGD) plant required for the use of amine solvent technology, transport via pipeline (Table 2), and dedicated storage infrastructure.

Table 1 – GGS2 IECM Modeling Matrix

Solvent	Econamine FG+					
% Capture	65	80	90	65	80	90
Auxiliary Boiler?	Yes	Yes	Yes	No	No	No
Solvent	Cansolv					
% Capture	65	80	90	65	80	90
Auxiliary Boiler?	Yes	Yes	Yes	No	No	No

Figure 2. Capture costs using a natural gas-fired auxiliary boiler to provide steam compared with avoided costs estimated by the IECM for Fluor's Econamine FG+ and Cansolv processes if deployed at GGS2, assuming inclusion of the wet FGD unit as a part of the capture system.

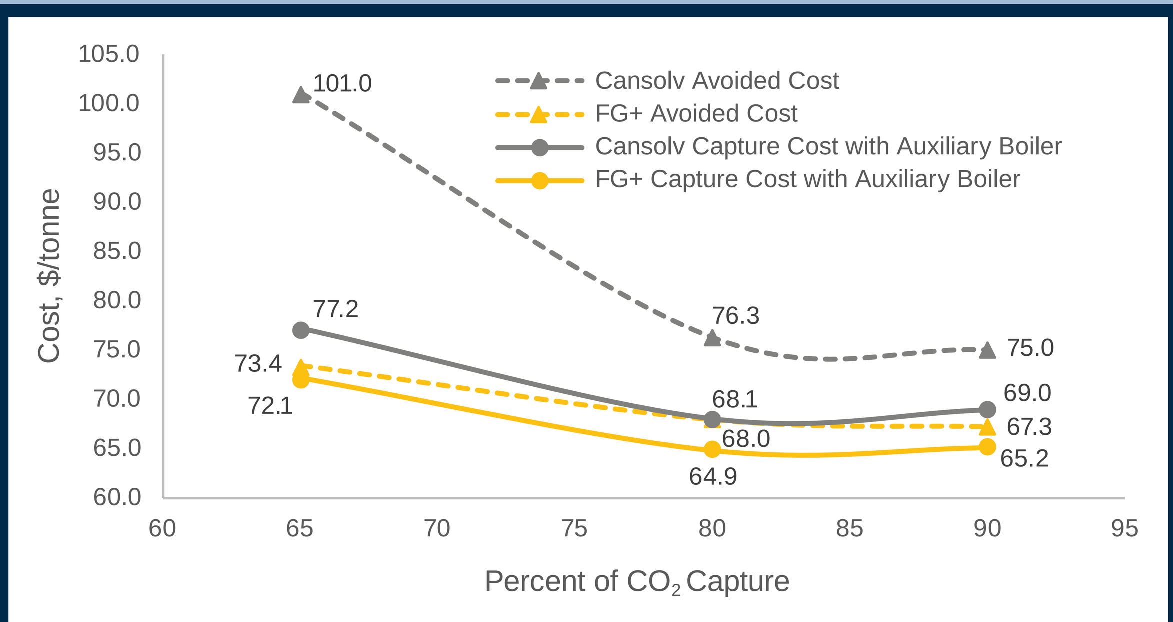

Table 2 – Preliminary Pipeline Economics for Potential CO_2 from GGS2

Capture Level (CO_2 produced)	90% (3 Mt/yr)			80% (2.6 Mt/yr)		65% (2.1 Mt/yr)	
Pipe Diameter, in.	20[1]	18		18		18	
Model	DOE	DOE	IECM	DOE	IECM	DOE	IECM
CAPEX, million	$96	$86	$70	$86	$70	$75	$65
OPEX, million[2]	$22	$22	$11	$22	$11	$22	$11
Total, million[2]	$120	$110	$81	$108	$81	$97	$76
Total CO_2 Transported,[2] Mt	89			79		64	
Cost CO_2, per tonne	$1.3	$1.2	$0.9	$1.4	$1.0	$1.5	$1.2

1 The IECM did not calculate a 20-in. pipe diameter.
2 Total over the assumed 30-yr pipeline lifetime.

Nebraska has no legislation in place to address typical CCS-specific issues, for example, pore space ownership for storage. Long-term liability therefore falls under the U.S. Environmental Protection Agency Underground Injection Control Program regulations.

SUBBASINAL ANALYSIS

Modeling and simulation studies identified an area to the southwest of GGS with the potential for storage of 50 Mt of CO_2 in the Cloverly Formation, constituting the most prospective deep saline formation and comprising sandstones with shales (Table 3, Figure 3). The area of review (AOR) that would be required for monitoring under a Class VI operating permit was estimated to range between 400 and 700 square miles (Figures 4 and 5). The viability of this storage option is subject to significant uncertainty due to the relatively limited amount of existing characterization data available to the pre-feasibility study; for example, dynamic simulation indicated that the proposed storage rate might require as few as two or as many as 14 injection wells. A key uncertainty is the relative proportion and distribution of sandstone and shale within the Cloverly Formation.

A preliminary, semiquantitative risk assessment also suggested uncertainty over storage capacity and injectivity constitute the most significant project risks at this pre-feasibility stage. None of the assessed risks were considered to rule out the possibility of a project moving to deployment.

Table 3 – Arithmetic Mean Values for Porosity and Permeability of Sand and Shale in the Three Models

	MODEL					
Property	P90		P50		P10	
Facies	Porosity, %	Permeability, mD	Porosity, %	Permeability, mD	Porosity, %	Permeability, mD
Sandstone	25.0	425	18.6	211	16.0	161
Shale	12.1	0.00001	9.72	0.00001	7.95	0.00001

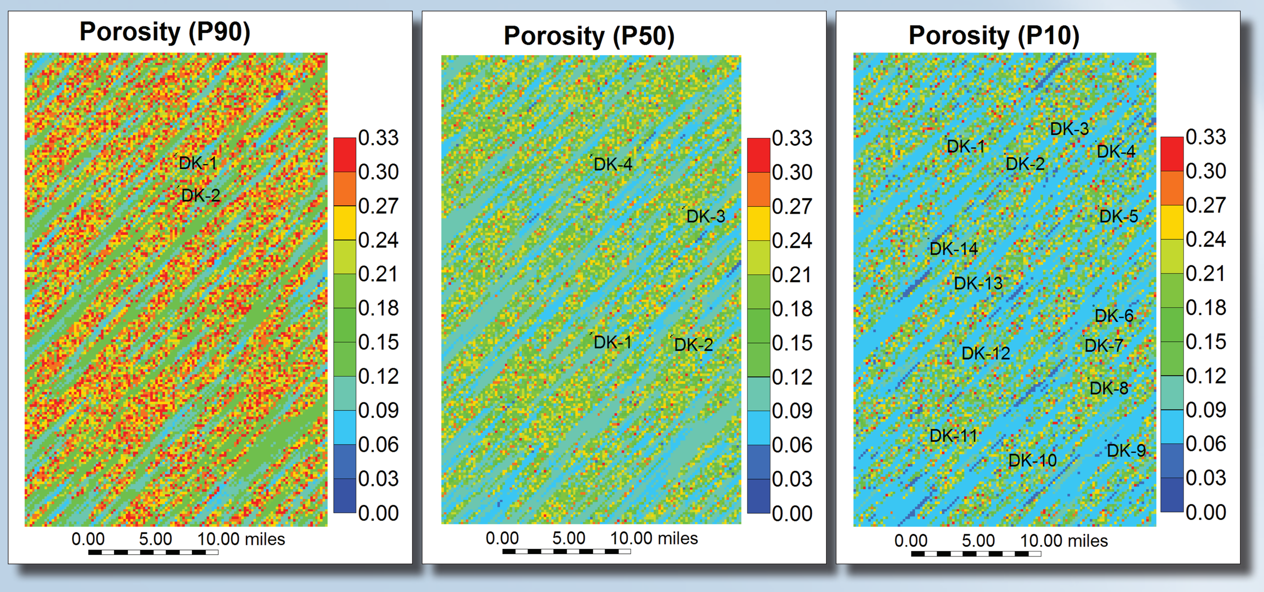

Figure 3. Porosity distributions (in plan view) with the potential well locations for CO_2 injection for P90, P50, and P10 models (from left to right). The injection wells are labeled "DK" (Dakota). The Cloverly Formation is the lower Dakota Group.

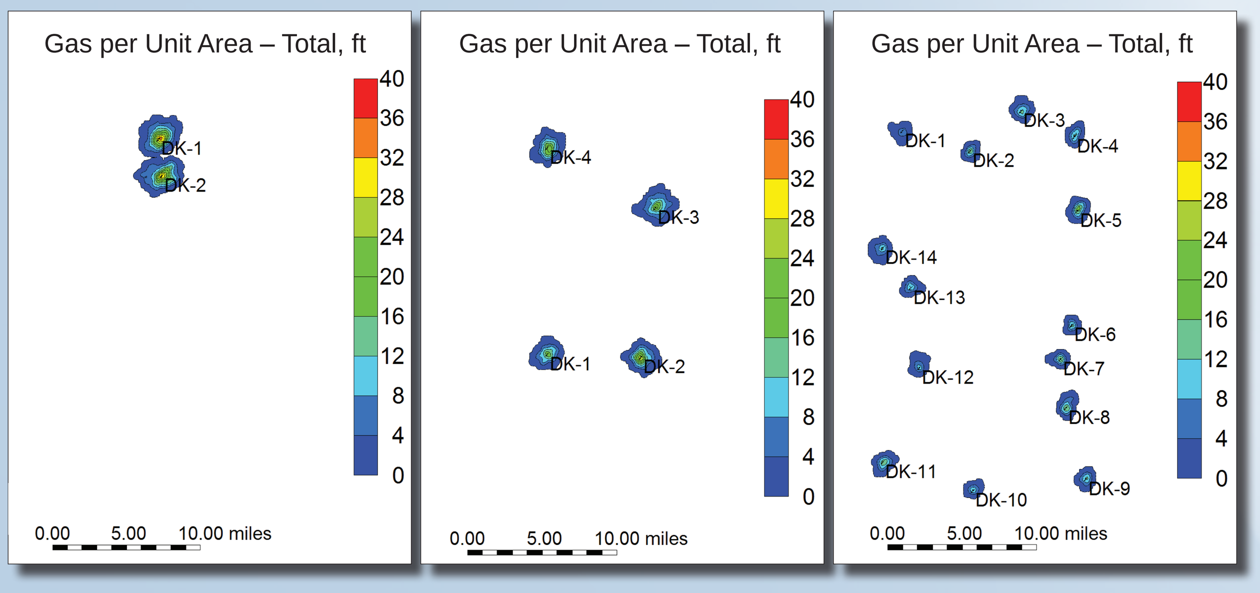

Figure 4. Simulated CO_2 plumes (in plan view) for the P90, P50, and P10 models (from left to right) at the end of a 25-year CO_2 injection operation.

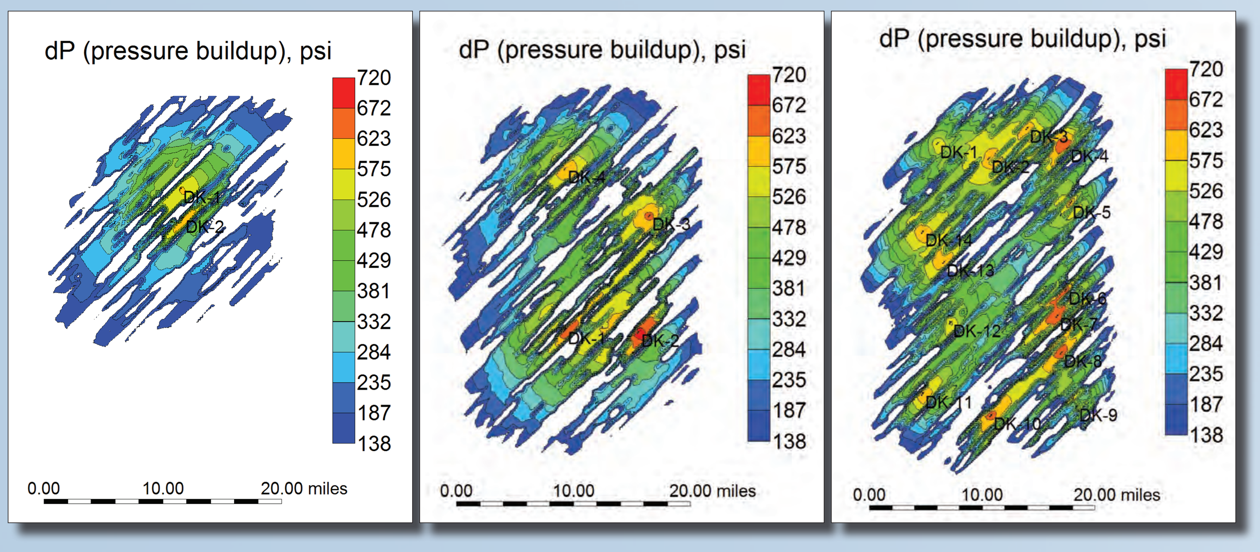

Figure 5. Simulated pressure plumes (in plan view) for the P90, P50, and P10 models (from left to right) at the end of a simulated 25-year CO_2 injection operation. The lower limit in pressure scale is bounded by the pressure threshold value of 138 psi.

SUMMARY AND CONCLUSIONS

In summary, the work undertaken in this Phase 1 pre-feasibility study has shown that western Nebraska has potential to host a commercial-scale CCS project, including a dedicated storage container for 50 Mt of CO_2. However, the following key challenges would need to be overcome:

1. The business case for deploying CCS projects is uncertain, with recently announced federal tax credits unlikely to compensate for the cost of CCS deployment at a coal-fired power station such as GGS. Sales of CO_2 for EOR could provide additional revenue but the combined benefits of tax credits plus EOR sales would still be unlikely to cover the costs of a CCS project at GGS, as estimated by this pre-feasibility study.
2. The potential 50-Mt CO_2 dedicated storage container defined in this pre-feasibility study should be regarded as having a relatively low level of readiness to support a CCS project. Significant further work, including exploratory drilling and geophysical surveys, would be required to provide sufficient certainty to support an investment decision in a Nebraska CCS effort.
3. Public outreach would be a vital element in western Nebraska, where sensitivities around such environmental issues as water resource protection and pipeline construction would need to be carefully addressed.

ACKNOWLEDGMENTS
This work was funded by DOE and NPPD. Technical support was provided by Schlumberger Carbon Services and Computer Modelling Group Ltd.