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Lessons Learned to Date for Application to Large Scale Carbon Dioxide Storage

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Over the past three decades the oil and gas industry has developed full-system approaches for safe and cost-effective injection of carbon dioxide (CO2). Projects have been executed successfully that inject into formations spanning a full range of depths, reservoir quality, pressures and temperatures. Injection has been into both aquifers and hydrocarbon bearing intervals. Lessons learned about site selection, storage design and site monitoring are directly applicable to current and future carbon dioxide geo-sequestration projects.

Large scale storage of CO2 designed for long term permanence of storage, however, will require improved understanding of basin scale structural architecture, reservoir connectivity and hydrodynamics. Estimates made by the IPCC and others are that most of the global useable storage capacity lies in deep saline formations where brine filled reservoirs with sufficient porosity and permeability to store large volumes of CO2. However, the majority of operational experience lies in oil and gas fields that are proven structural traps for hydrocarbons but have limited volumes of pore space within the structural traps or are not conveniently located to large stationary sources of CO2 emissions. Pressure and production / injection data and related basin studies from areas where long term oil and gas production has been combined with gas and brine injection provide a useful framework for capturing lessons learned that can be applied to the deep saline formations that lie in-between oil and gas fields.

In this paper the focus will be on storage project field experience in varied geological environments and a basin study where data has been collected and analyzed over several decades. Also discussed will be options to optimize well rates and location to maximize the storage volumes of CO2 injection in a large scale scenario. Safe, efficient and reliable long term storage of CO2 will require knowledge and observance of limits on cap rock fracture pressures, location of formation spill points and controlled rates of injection to mitigate adverse sweep related to gravity override of injected gas.

Interdisciplinary study outcomes and key design parameters for three different storage scenarios will be discussed. One will be a depleted oil field in an anticline structure connected to a regional aquifer; a second will be storage into a deep and lower quality aquifer underlying a gas field and a third will be assessment of potential storage in a large regional aquifer in pressure communication with active producing fields. Also, by use of materials from a basin wide study we will illustrate that site specific geological and engineering data combined with detailed dynamic modeling is very important to a complete appraisal of storage site integrity and capacity.

Brief synopses of the examples to be discussed are given below:

1. Storage in a depleted oil and gas field with the structural trap being a salt supported structure and spill point connections to a large sedimentary basin containing other oil and gas fields

    The subject depleted field is a large anticline dome structure with an excellent multi-darcy sandstone formation that previously produced oil while both water and gas were re-injected for pressure maintenance. In the final stages of production the natural gas was produced from the crest of the structure with resulting loss of pressure in the reservoir. Since that time the underlying regional aquifer has been entering the reservoir by flow through structural spill points and re-pressuring the multiple porous sand intervals. Modeling of the reservoir was done to test the sensitivity of storage efficiency to key reservoir parameters on quantity and efficiency of storage in this field. Given that the field had previously contained oil, the model was also run to determine if enhanced oil recovery could be monetized as part of the project. To model the safety constraints of the injection-only operation, the injection pressure in injection wells located at the crest of the structure was kept below the original pressure of the gas cap at time of field discovery

2. Storage in a deep saline carbonate formation adjacent to a producing gas field

    The subject of the second study is a field produces gas from a deep, thick multi-zone carbonate on the crest of a regionally plunging anticline. The in situ gas is 20% methane with the rest being inerts that are stripped from the sales gas at the gas plant. Two downdip injectors are re-injecting 60MMscf/d acid gas (65% H_2S, 35% CO_2) into the aquifer some 40 miles removed from the crestal production area – one of the world's largest acid gas re-injection projects. The injection zone is 17,000 feet depth, is 800 feet thick with a porosity of 8-10% and permeability of 10-50 md. The study looked at plume migration and possible inter-well interference from multiple acid gas injection wells.

3. Storage in a deep saline sandstone formation with demonstrated pressure connectivity to producing oil and gas fields

    The third study looked at options for CO_2 sequestration in a large regional aquifer where ongoing oil and gas production occurs from connected formations and was designed to investigate conditions and timeframes where contamination could occur. The target formation is a thick multi-darcy sandstone with interpreted discontinuous shale layers and coal seams that will serve as baffles but are not expected to be barriers to the CO_2 plume as it migrates after injection. The driving force for plume migration will be its buoyancy, the basin hydrodynamics and pressure sinks caused by the producing fields. Injection of CO_2 significantly below the producing horizon was assumed. It was recognized, however, that long term containment of the CO_2 would likely be achieved via the same overlying regional seal which allows for hydrocarbon traps in the region. It was therefore expected that ultimately the CO_2 would migrate into depleted fields that would provide for ultimate containment

4. Basin wide hydrodynamics in the presence of large scale and long term injection and production operations from multiple oil and gas fields and a known recharge zone in outcrops

    The fourth basin study looked at the hydrodynamics in a large regional aquifer with a multi-decade history of oil and gas production and injection of both brine and inert gas to and from connected formations. The target formation is high permeability sandstone with layering and variable quality sub units. A North-South fault creates a trap for hydrocarbons but does not completely segregate brine and pressure responses across the basin. The driving force for brine movement is the pressure sinks caused by the producing fields. The pressure sources include brine disposal, inert gas injection and natural recharge at the locations of outcrops. Injection of CO2 on a large scale would introduce another pressure source. Large scale CO2 plumes would be steered by the basin pressure gradients and local geology. It is therefore expected that some of the CO2 would migrate into depleted oil and gas field structures that would provide for ultimate containment.