Natural CO_2 Reservoirs on the Colorado Plateau and Southern Rocky Mountains: Candidates for CO_2 Sequestration.

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Abstract

Numerous natural accumulations of CO_2-dominant gases have been discovered as a result of petroleum exploration in the greater Colorado Plateau and Southern Rocky Mountains region. Some CO_2 fields, notably Bravo Dome (NM), McElmo and Sheep Mountain (CO), Farnham Dome (UT), Springerville (AZ), and Big Piney-LaBarge (WY) have been produced for commercial purposes. CO_2 concentrations are frequently more than 98%, indicating that these subsurface accumulations provide excellent analogues for studying the long-term effects of underground CO_2 storage. They may also provide sites for storing additional CO_2 if it can be separated from the flue gases of coal-fired power plants in this part of the U.S. This paper reviews the characteristics of many of the known CO_2 fields as the first phase of a three-year project.

Most CO_2 fields are similar to conventional natural gas fields, with the gas trapped in dome-like structures. The most common reservoir lithologies are sandstone and dolomite, with mudstone and anhydrite being the most common sealing rocks. The horizontal dimensions of the gas reservoirs (~ 10 km) are typically 100 times larger than the reservoir thickness. Stacked reservoirs (or gas occurrences) are not uncommon, indicating that gas has migrated up through the sedimentary section. The gas storage in the well-known reservoirs ranges from 1 – 100 trillion cubic feet (TCF; gas at standard temperature and pressure; 28 – 2800 billion m^3) with 1 – 10 TCF being common. This compares with a CO_2 volume of 4 TCF (100 billion m^3) issued from the stacks of a 1000 MW coal-fired plant over 20 years. Initial findings about the pore fluid chemistry at depth, and evidence for reactive effects of rock-CO_2 fluid interactions are discussed. The physical and chemical characteristics of these reservoirs will be used to constrain

numerical models of the effects of CO_2 injection into reservoir rocks similar to those found on the Colorado Plateau, using the simulator CHEMTOUGH2.

Introduction

The greater Colorado Plateau-Southern Rocky Mountains region contains numerous occurrences of natural CO_2 that have been discovered during exploration for oil and gas fields (Fig. 1). These occurrences provide a natural laboratory for studying the effects of long-term, subsurface storage of CO_2. If core, cuttings or well logs are available, inferences about the reservoir rocks and the surrounding seal rocks may be possible. Whereas laboratory simulation of the fluid-mineral reactions between CO_2 and reservoir rocks has been difficult and necessarily of short duration, natural CO_2 reservoirs offer opportunities to assess the long-term reactions (Pearce et al., 1996; Gunter et al., 1997). The effectiveness of seals can also be examined, including the effects of CO_2 leaking into overlying aquifers and whether these natural leaks pose significant environmental threats or impacts. Many of these natural CO_2 reservoirs are situated close to coal-fired power plants (Fig. 1). If CO_2 can be economically separated from power plant flue gases, some of these reservoirs may be suitable candidates for sequestering the CO_2.

The purpose of this paper is to present results from the start-up phase of our DOE-funded project to investigate the reactive behavior of CO_2 in saline aquifers beneath the Colorado Plateau. We review the characteristics of the published natural occurrences of CO_2, their production history, and where available, the fluid chemistry of the reservoir pore water. In a companion paper (White, 2001, this volume) the initial phase of numerical simulation of the reactive chemistry of CO_2-water-rock with CO_2 injection is presented.

Natural CO_2 Production Rates and Volumes

The CO_2 that has been naturally trapped in sedimentary rocks (reservoirs) of the Colorado Plateau and Southern Rocky Mountains region is present in concentrations that can exceed 98% purity. Many of these reservoirs (surface locations known as “fields”) have been developed for CO_2 production for dry ice sales, industrial uses, or for subsurface injection to enhance oil recovery. Because of the limited use of CO_2, and the remote locations compared to potential markets, only five reservoirs remain commercially viable (2001). Four of the five reservoirs are shown on Fig. 1 with CO_2 pipelines leading to the respective markets (the fifth is McCallum, CO). The dominant use is enhanced oil recovery. The largest active production occurs at McElmo Dome, near the Four Corners, where approximately 15 Mt/y (million tonnes/year; ~ 300 billion cubic feet (BCF)/year at standard temperature and pressure) of CO_2 is piped 800 km to the Permian Basin in West Texas (Colorado Oil and Gas Conservation Commission website). A small fraction of the CO_2 is piped westwards to the Greater Aneth oil field in Utah. A second pipeline to the Permian Basin transports close to10 Mt/y of CO_2 from Bravo Dome (NM; 70% of the flow) and Sheep Mountain (CO; 30%). CO_2 is also produced from the Big Piney-LaBarge field, (WY, includes three field units known as Fogarty Creek, Lake Ridge and Graphite; data from Wyoming Oil and Gas Conservation Commission, 2/2001). Approximately 1 Mt/y is piped to each of Wertz oil field (WY) and Rangely oil field (CO). However, the LaBarge gas processing plant (Shute Creek) vents an additional 6 Mt/y of unwanted CO_2 production, largely because of the value of the other gases produced along with the CO_2 (CH_4, N_2, He; Doelger et

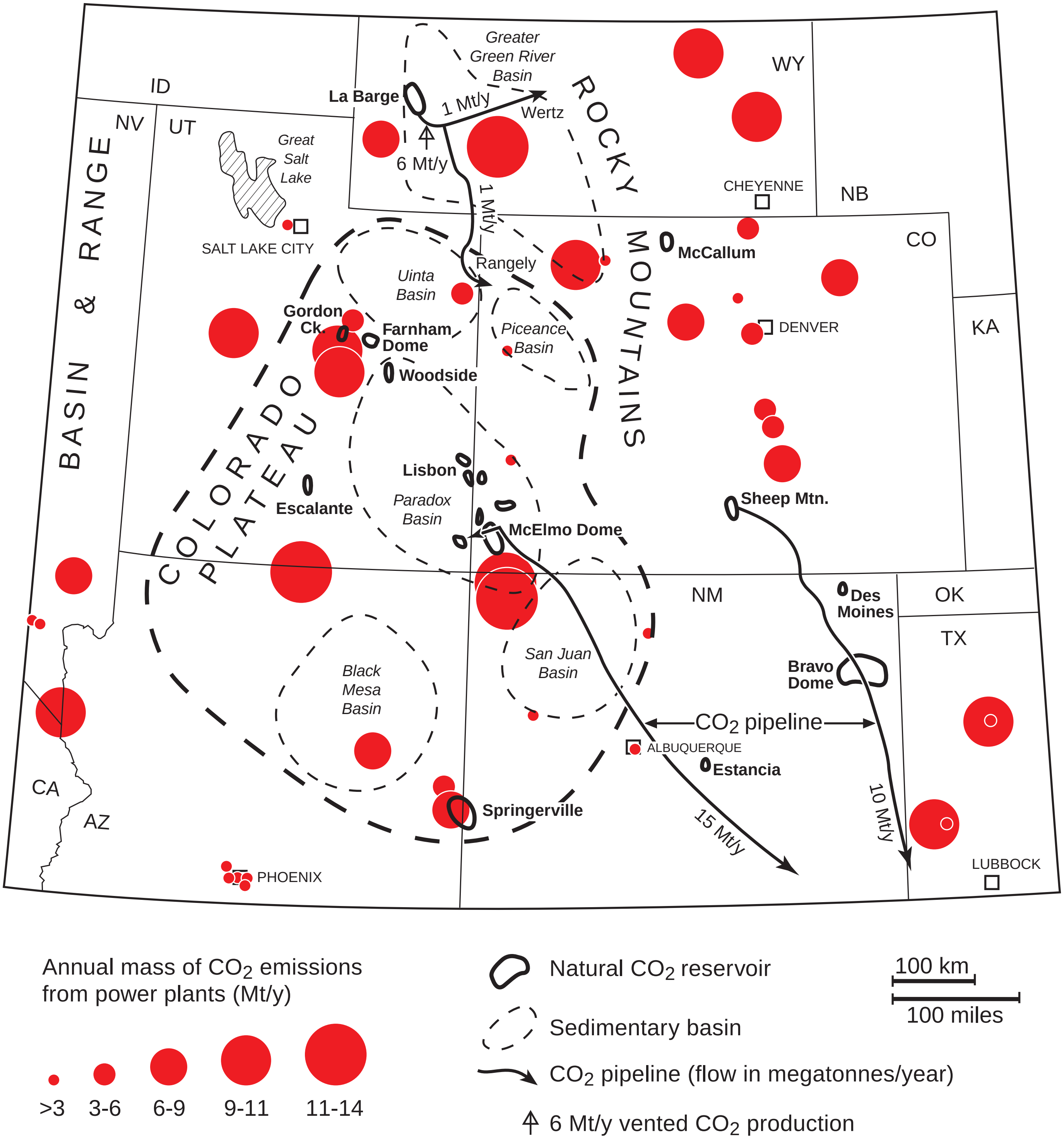

Fig. 1. Synthesis of data relating to CO_2 fluxes and concentrations around the Colorado Plateau. Power plant emissions are from Hovorka (1999; numbers rounded off); natural CO_2 reservoirs are from references listed in text; CO_2 pipelines and fluxes from references in text.

al., 1995). McCallum field (CO) produces about 0.06 Mt/y of CO_2, apparently for industrial uses.

The largest cumulative volumes of CO_2 produced from these fields (through 1999) are at McElmo (3.3 TCF; 92 billion m^3), Bravo Dome (1.9 TCF), Big Piney-LaBarge (~ 1.7 TCF; > 2 TCF total gas), Sheep Mountain (1.2 TCF), and McCallum (0.7 TCF). These volumes (or equivalent masses) allow comparison with the flux of CO_2 gas from fossil fuel-fired power plants. Qualitative comparisons can be made from Fig. 1, based on the size of the emissions symbol (after Hovorka, 1999). The CO_2 field extraction rates (1-15 Mt/y; million tonnes/year) are similar in magnitude to the CO_2 emissions rate from the power plants. Alternatively, if the theoretical CO_2 emissions from a 1000 MW coal-fired plant are assumed to be 9 Mt/y (DOE, 1999), then the volume of CO_2 at standard temperature and pressure after 20 years is 3.6 TCF. This is similar in magnitude to the total volume of gas withdrawn from McElmo Dome field since large-scale production began in 1982. The total gas stored in many of the CO_2 fields shown on Fig. 1 is typically in the range of 1 – 100 TCF per field (where reserve estimates have been published). Big Piney-LaBarge is the largest, with reserves estimated to be more than 100 TCF, but more commonly reserves are in the range of 1 – 10 TCF. These estimates qualitatively indicate that the type and size of structures that have naturally trapped CO_2 are suitable for storing a significant volume of power plant CO_2 emissions. We therefore review their characteristics to provide a better understanding of how the gas is stored, and the nature of the reservoir-seal rocks.

Summary of CO_2 Field Characteristics

Notable characteristics of the major CO_2 fields in the Colorado Plateau-Southern Rocky Mountains region are listed as an Appendix to this paper. A review of these suggests that CO_2 reservoirs are not substantially different to conventional natural gas reservoirs. The gas collects in structures capable of trapping low-density fluids. Typically these are anticlines (broad folds) of permeable rock units capped with low permeability units. Occasionally the traps may be fault bounded, and occasionally a facies change (lateral change in lithology within the unit) may provide a boundary zone. An example of a large trapping structure is shown in Fig. 2, the Big Piney-La Barge anticline. An unusual feature of this reservoir is the density stratification of the gases (Doelger et al. 1993). The CO_2 has its greatest concentration in the deeper parts of the reservoir; CH_4 concentrations are highest near the highest part of the reservoir. It is possible that this effect could be enhanced by CO_2 exolving from the underlying pore water when deep production wells locally de-pressure the reservoir.

In all cases the geometry of these reservoirs is such that the horizontal dimension greatly exceeds the vertical dimension. Typically the reservoir thickness is of the order of 100 m or less, and the horizontal dimension of the order of 10 km, a ratio of 1:100. This is indicative of the gross permeability anisotropy of the trapping structure. The permeability of the reservoir units (i.e. producing intervals) typically exceeds 10 mD, whereas the low permeability of the overlying sealing units characteristically is on the order of μD or less. Faults, fractures, lateral changes in lithology and the effects of post-depositional mineral alteration can cause the permeability and porosity (i.e. storage capacity) of both reservoirs and seals to vary greatly, causing complexity in an apparently simple reservoir-trapping structure. In many of the CO_2 fields, gas is found at multiple depths indicating that the gas has migrated vertically through the sedimentary column. This has implications when considering the long-term effects of CO_2 injection into these or other similar sedimentary structures.

The most common reservoir lithologies are sandstone, dolomite, and fractured basement rock. Sandstone and carbonate reservoirs are the most common natural gas reservoirs. The significance of the frequency of dolomite ($MgCa[CO_3]_2$) reservoirs trapping CO_2, rather than the more commonly occurring limestone ($CaCO_3$) reservoirs is not known. Dolomite can be naturally very porous as a result of the dolomitization process of limestone, and can occur early (soon after deposition), so high porosity is not necessarily an indicator of reaction processes with CO_2-rich fluids.

Predominant seal lithologies appear to vary between mudstone/shale units and anhydrite ($CaSO_4$). There are no obviously unusual characteristics reported about the sealing lithologies or the trapping structures that point towards precipitation reactions caused by the presence of CO_2-rich fluids.

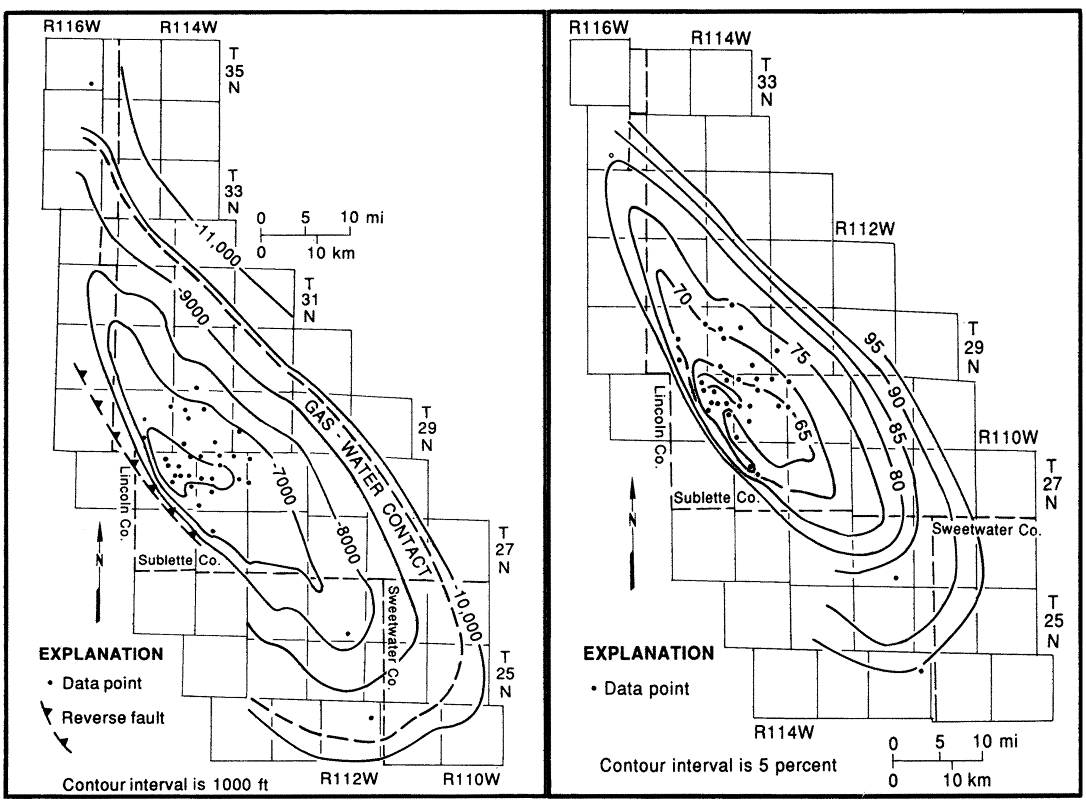

Fig. 2: Structural contours (elevation in feet above sea level) on the top of the main reservoir unit of the Big Piney-La Barge CO_2 field *(left figure)*. Percentage of CO_2 within the main reservoir unit *(right)*. Less dense gases (especially CH_4 and N_2) are more concentrated towards the top of the reservoir. Both figures from Doelger et al. (1993).

There appears to be only one published study that has investigated possible fluid-rock interactions in these fields as a result of the presence of CO_2-rich fluids (Pearce et al., 1996). They investigated the evidence for reactions within the Tubb Sandstone reservoir of the Bravo Dome field. They reported dissolution of early anhydrite, dolomite and detrital plagioclase and attributed this to the introduction of CO_2-rich groundwater. They also speculated that precipitation of halite and calcite could have contributed to the sealing potential of overlying rocks, but admitted there was no evidence for this at Bravo Dome. Investigation of the fluid-rock interactions at other CO_2 fields in the Colorado Plateau-Southern Rocky Mountains region is an important part of our present study.

Pore Water Chemistry

Large changes in pore water chemistry occur across the Colorado Plateau-Southern Rocky Mountains region, due partly to the variations in lithology and solubility, and also to the extent of flushing by meteoric water movement. The Pennsylvanian evaporite (salt) deposits of the Paradox Basin are not surprisingly associated with highly saline groundwater, whereas near-surface waters being recharged from adjacent mountains tend to be relatively unmineralized and pristine. Few of the publications about the CO_2 fields include data on the co-existing pore water chemistry, although the presence of acidic water corroding the steel casing of CO_2 production wells is a common occurrence. Pore water chemistry is an important factor influencing the amount of CO_2 that is dissolved in the water, and the extent to which precipitation of carbonate minerals may permanently sequester CO_2 at depth. We have therefore begun reviewing the available data on the chemistry of groundwaters of the region. At this time we have only considered data from eastern Utah and the Four Corners area.

Papers on the hydrology of groundwater of the Utah portion of the Colorado Plateau include Hanshaw and Hill (1969), Avery (1986), Howells (1990), Freethy and Cordy (1991), Gwynn (1995) and Spangler et al. (1996). For this paper, we have sorted the compilation of chemical analyses in Gwynn (1995) by depth and location in order to highlight the gross chemical trends and differences. The compilation includes oil-well brine, shallow well-water and springs. The county location was used as a primary sort criterion, and analyses falling within 200 – 300 m elevation intervals (or other convenient breaks based on data frequency) were then averaged. A few obviously anomalous analyses were excluded.

In Fig. 3 we contrast the trends in the major anions from the Paradox Basin (Grand and San Juan Counties) with that in the southern Uinta Basin (Grand and Emery Counties). The 32 average analyses depicted represent a total of over 650 individual analyses. In both regions, the chloride concentration increases by approximately four orders of magnitude over a depth range of 3 – 4 km. In contrast, the sulfate concentration increases 1 – 2 orders of magnitude over the first 1 – 2 km of depth and then is fairly uniform with increasing depth; the bicarbonate concentration is remarkably uniform over all depths. The principal difference between the two areas is the presence of saline waters at shallower depth in the Paradox Basin due to the presence of relatively thick salt deposits.

Consideration of the full analyses indicates that the waters of the southern Uinta Basin are generally a calcium-sulfate-bicarbonate type at elevations of more than 1 km above sea level (asl), and a sodium-chloride-sulfate type at intermediate depths which trends towards a sodium chloride water below sea level. In the Paradox Basin, the shallow waters are also a calcium-sulfate-bicarbonate at shallow depth (elevations more than about 1.5 km asl), changing to a sodium chloride water at greater depth. The concentration of total dissolved solids (TDS) in both areas increases from several hundred mg/kg at shallow depth, to almost 200,000 mg/kg at depth.

The analyses available from the Bravo Dome CO_2 reservoir (New Mexico) are similar to the intermediate concentration waters depicted in Fig. 3, being a sodium chloride water with slightly elevated bicarbonate levels (TDS 27,000 – 44,000, Cl 11,000 – 23,000, HCO_3 3,300 – 3,900, SO_4 1,400 – 1,900 mg/kg). Although our analysis of the groundwater chemistry trends is incomplete, we believe the trends shown in Fig. 3 are probably typical for most of the Colorado Plateau – Southern Rocky Mountains region.

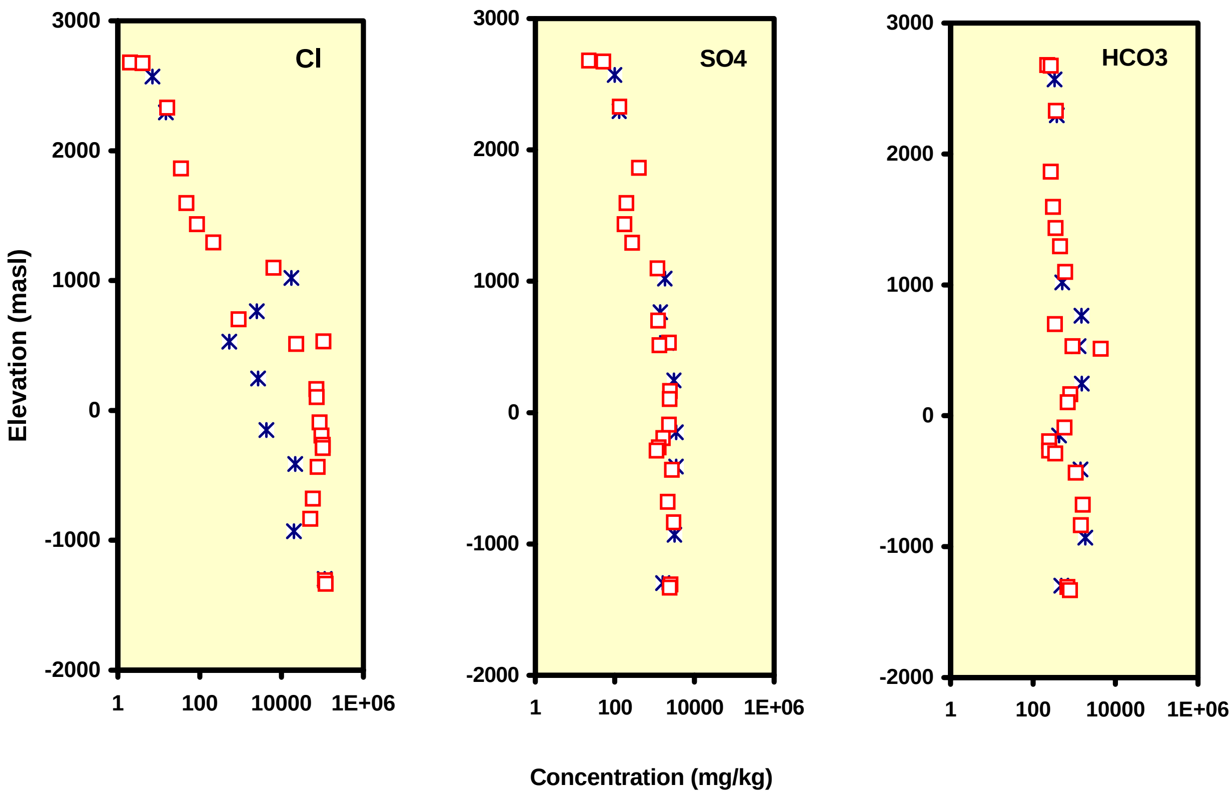

Fig. 3: Trends in anion concentrations with depth beneath the Utah portion of the Colorado Plateau. Squares are from the Paradox Basin in southeast Utah; crosses are from the vicinity of the Uinta Basin in central and northeastern Utah (basin locations in Fig. 1). Each point represents an average over a selected depth interval. Data are from oil wells, shallow wells and springs (Gwynn, 1995; and other data on file at the Utah Geological Survey).

Near-Surface Evidence of CO_2 Flux

The perfect reservoir and trap rarely exist, with most reservoirs leaking to some degree. The critical question is the rate of gas loss towards the surface and its ultimate fate. In the petroleum exploration industry, surveying for shallow soil gases or submarine pore fluid chemistry anomalies is a common exploration tool. The shallow anomalies can point to a possible reservoir at depth, and furthermore may indicate the nature of the trapped fluid (Schumaker and Abrams, 1998). Evidence of natural CO_2 leakage to the surface occurs in eastern Utah (near Crystal Geyser south of the town of Green River, between Farnham Dome and Woodside on Fig. 1). Travertine has been precipitated, and a nearby abandoned well geysers intermittently (Baer and Rigby, 1978).

Extensive bleached zones visible within red sandstone outcrops around the Colorado Plateau have been commented on for many years. Recent work by Chan et al. (2000) suggests saline groundwater that has interacted with hydrocarbons, organic acids, or H_2S, has reduced the ferric iron to more soluble ferrous compounds, and at shallower depth these waters have mixed with oxygenated groundwater causing precipitation of iron and manganese cements. We question whether groundwater saturated with CO_2 could also cause bleaching of red sandstone. The pore water from CO_2 reservoirs rapidly corrodes steel production casing, and in geothermal settings, shallow CO_2-rich waters have been known to corrode both grout and casing within a matter of years (e.g. Hedenquist and Stewart, 1985). It is interesting that the production zone from fractured basement granite beneath the Springerville (Arizona) CO_2 field is extensively altered (Rauzi, 1999), whereas non-productive basement is apparently not altered. We are currently investigating core from this field to see whether the alteration is consistent with interaction with CO_2-rich fluids.

One of the major concerns about subsurface sequestration of CO_2 is the potential for the gas to return to the surface in relatively large volumes, not only negating the original sequestration intent, but also causing a potential environmental hazard through ponding in low-lying areas. As part of our present study we hope to ascertain the extent to which CO_2 is naturally seeping to the surface in the vicinity of known CO_2 reservoirs. For example, the main reservoir at Farnham Dome (central Utah) is only at 900 m depth, whereas that at nearby Gordon Creek is at 3300 - 3900 m depth. We suspect the shallower the reservoir, the more chance for surface leakage and the less chance for sequestering the CO_2 as dissolved species in the groundwater or as carbonate. Numerical modeling using the simulator CHEMTOUGH2 will assist interpretation of the results (White et al., this volume).

Conclusions

About 10 natural CO_2 fields in the Colorado Plateau-Southern Rocky Mountains region have been exploited at some time for their gas. Many more occurrences of high CO_2 concentrations have been encountered by exploration wells in this region. Five fields are still in production, largely to assist oil production through CO_2 injection. Of the 33 Mt/y of produced CO_2, 25 Mt/y is transported from McElmo Dome, Sheep Mountain and Bravo Dome by two 800 km-long pipelines to West Texas. An additional 8 Mt/y is produced from the Big Piney-La Barge field, but 6 Mt is currently vented to the atmosphere.

The natural CO_2 fields provide analogues for assessing the long-term effects and effectiveness of injecting flue gas CO_2 into basins containing saline aquifers. The natural CO_2 reservoirs do not appear to have significantly different characteristics to conventional natural gas reservoirs. They occur in structural highs which facilitate the trapping of low density pore fluids in naturally saline aquifers. The dominant reservoir lithologies are sandstone, dolomite, and fractured basement and sealing rocks are predominantly low permeability mudstone/shale or and/or anhydrite. Permeability anisotropy in the sediments ensures that the horizontal dimensions (~ 10 km) are typically 100 times greater than the reservoir thickness. The estimated gas storage of many of the produced CO_2 reservoirs appears to be comparable to the amount of CO_2 gas that would be emitted from a 1000 MW power plant over 20 years.

Based on the chemical data available from eastern Utah, pore fluid chemistry varies from a relatively dilute (< 1000 mg/kg TDS) calcium-sulfate-bicarbonate water at shallow depths, to a sodium chloride brine (TDS > 100,000 mg/kg) below about 1 km below sea level. Lithology and the extent of meteoric recharge appear to be the dominant factors controlling the water chemistry.

Many CO_2 fields have multiple, stacked “reservoirs,” indicating movement of CO_2 vertically through the sedimentary column (e.g. see Escalante field in Appendix). The variability of reservoirs and their trapping rocks points to natural complexity in most basins. Assumptions of the existence of a perfect reservoir with an impermeable boundary for permanently trapping injected CO_2 are probably unrealistic. The implications for injecting CO_2 separated from flue gases may be to ensure that the subsurface migration path for CO_2 is long, both spatially and temporally, thereby maximizing the opportunities for sequestering the CO_2 as dissolved species and carbonates in deep reservoirs. Despite the abundance of CO_2 reservoirs in the Colorado Plateau-Southern Rocky Mountains region, and the inferred widespread, active flux of CO_2 to the surface, no hazards from surface CO_2 accumulations are known. More work is needed in the vicinity of known CO_2 fields to study the nature and rate of surface leakage.

Numerical modeling of the multi-phase, reactive effects of CO_2-rich fluids and the country rock is an important component of this project. The simulator CHEMTOUGH2 will be used, as reported in a companion paper (White et al., this volume). This modeling will hopefully provide insight into the fate of injected CO_2 and will clarify some of the present uncertainties regarding the subsurface movement of CO_2. Constraints available from CO_2 reservoir analogues in the Colorado Plateau-Southern Rocky Mountains region should greatly assist this study.

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Appendix: Characteristics of major CO_2 fields in Colorado Plateau-Rocky Mountains

References are included in the above list. Some fields have additional discussion where information has not been previously published, or the material is in reports with limited availability. Other fields with high reported CO_2 concentrations exist in the same region, but are not described here. Some of these are shown on Fig. 1. Volumes and flow rates are given in both SI and conventional oil industry units (28 m^3 = 1 thousand cubic feet, or MCF; MM = million; B = billion; T = trillion). Production flow rates and volumes are at standard temperature and pressure. 379 standard CF of CO_2 = 44 lbs, or 20 kg; i.e. 1 million tonnes = 19 BCF CO_2.

Farnham Dome, Utah

Area: 10 km^2
Average Depth: 900 m
Reservoir Lithology: Jurassic Navajo Sandstone forming a north-trending anticline, faulted on its west side.
Net Thickness: 12 m (40 ft) average thickness of the gas saturated interval
Gross Thickness: 100 m (330 ft) average formation thickness
Seal Lithology: Carmel Formation, interbedded limestone and shale
Gas Composition: CO_2 98.9%, N_2 0.9%, O_2 0.2%, HC 0%
Production History: Produced 135 million m^3 (4.8 BCF) gas, which was transported via surface pipeline to a nearby dry-ice plant. Production first began in 1931. In 1972 the field was shut in when the dry-ice plant was closed.
Porosity and Permeability: The average porosity is 12% intergranular, in a moderately homogenous eolian sandstone. Permeability is unknown but may be high (>100 mD) based on the high initial gas flow rates (453,000 m^3 [16 MMCF])
Secondary Reservoir: The Triassic Sinbad Limestone Member of the Moenkpoi Formation tested 76,500 m^3 (2.7 MMCF) of CO_2 gas but was never produced. The Sinbad Limestone is typically a low-porosity, low-perm, reservoir that ranges in thickness from 15 to 46 m (50 to 150 ft) in the Farnham Dome area (1400 m depth). The high gas flow test rate indicates fracturing may be an important component of the reservoir. The overlying seal is the upper member of the Moenkopi that is composed of interbedded red shale and siltstone.
Reference: Morgan and Chidsey (1991).

Big Piney – La Barge Area, Wyoming

Area: 3500 km^2

Average Depth: 4500 m
Reservoir Lithology: Mississippian Madison shallow shelf dolomitized limestone; (reservoir predominantly dolomite)
Net Thickness: 136 m (450 ft) average thickness of the gas saturated interval
Seal Lithology: Upper Madison sabkha deposits with a karst breccia on top overlain by Pennsylvanian Weber Sandstone
Gas Composition: HC 1 to 22%, CO_2 66% to 90%+, N_2 7%, H_2S 4.5%, He 0.5%
Porosity and Permeability: Porosity ranges from 6 to 12%
Total Reserves: Estimated to be 134 TCF.
Additional Comments: The reservoir(s) comprise Federal Units Lake Ridge, Fogarty Creek, Graphite, and Tip Top. The trap is a large anticline with a relatively steep dip on its west side where it is bounded by an east-dipping thrust fault. Gas is produced to the Shute Creek gas plant with a capacity of 17 million m^3 per day (600 MMCF/D). The gas is typically 2/3 CO_2. Generally, 2.8 million m^3 per day (100 MMCF/D CO_2) is piped to Rangely oil field in Colorado and 2 million m^3 per day (75 MMCF/D) is piped to Lost Soldier and Wertz oil fields in Wyoming, for tertiary oil recovery. About 6.4 million m^3 per day (225 MMCF/D) CO_2 is vented to the atmosphere. As CO_2 begins to be recycled in the tertiary oil recovery fields, more CO_2 is being vented due to a lack of markets.
References:
De Bruin (1991); Doelger et al. (1993).

Gordon Creek, Utah

White Rim Sandstone Reservoir
Area of Reservoir: 34 km^2
Average Depth: 3,900 m
Lithology of Reservoir: Permian White Rim Sandstone
Net Thickness: 150 to 200 m; 50 m net pay
Lithology of Seal: dolomite (Permian Black Box Dolomite)
Gas Composition: 98.82% CO_2, 1.03% N_2, 0.01% O_2, 0.14% CH_4
Production History: none
Porosity-Permeability Characteristics: 8 to 12 % porosity (permeability is unknown), intergranular and fracture porosity

Moenkopi Formation, Sinbad Limestone Member
Area of Reservoir: 34 km^2
Average Depth: 3,340 m
Lithology of Reservoir: Sinbad Limestone Member of the Triassic Moenkopi Formation
Net Thickness: 15 to 18 m; 7 m net pay
Lithology of Seal: shale and siltstone (Torrey Member of the Moenkopi Formation)
Gas Composition: 99.5% CO_2, 0.1% CH_4, 0.1% C_2H_6, 0.1% higher fractions, 0.01% O_2, trace - He, trace - Ar
Production History: none
Porosity-Permeability Characteristics: 6% porosity (permeability is unknown), intercrystalline, fracture porosity

Additional Comments: Gordon Creek field was discovered in 1947 with the completion of the Gordon Creek Unit No. 1 (SE1/4NE1/4 section 24, T. 14 S. R. 7 E., Salt Lake Base Line & Meridian) by Pacific Western Oil. Gas flowed at an estimated rate of 252 m^3 (8,900 thousand cubic feet [MCF]) and 240 m^3 (8,500 MCF) per day from the Permian White Rim Sandstone and Sinbad Limestone Member of the Triassic Moenkopi Formation, respectively. The White Rim is an eolian dune deposit. The Sinbad is a fine-grained, dense carbonate deposited in a near-shore marine environment. The high flow rates from these units suggest the presence of extensive fracturing.

The trap is a northeast-southwest-trending anticline approximately 14.5 km long and 8.1 km wide. The structure has 150 m of closure on the surface. A fault zone sub-parallel to the structural axis has developed a graben dividing the anticline. Stratigraphic separation on the faults ranges between 15 and 30 m. Most if not all of the faults in the Gordon Creek area merge with a basal detachment in the evaporite section of the Jurassic Arapien Shale.

There has been no production of carbon dioxide from Gordon Creek field due to the lack of both a pipeline and a market for the gas. However, estimated recovery of carbon dioxide from the White Rim Sandstone and Sinbad Limestone is about 4 billion cubic meters (140 billion cubic feet) of gas.
References: Campbell (1978); Chidsey and Chamberlain (1996); Chidsey and Morgan (1993); Moore and Sigler (1987); Morgan and Chidsey (1991); Peterson (1961); Walton (1954).

Escalante, Utah

Cedar Mesa Sandstone

Area of Reservoir: 150 km^2
Average Depth: 960 m
Lithology of Reservoir: Permian Cedar Mesa Sandstone
Net Thickness: 387 m; 185 m net sand
Lithology of Seal: shale (Permian Organ Rock Formation)
Gas Composition (co-mingled with other formations): 96.1-93.1% CO_2, 2-5.5% N_2, 0-0.2% O_2, 0.7-0.4% methane, 0.2% ethane, 0.3-0%, 0.1% butane, 0.1% argon, 0.1-0.3% He, 0-0.4% H_2
Production History: none
Porosity-Permeability Characteristics: 12-16% porosity (permeability is unknown), intergranular and fracture porosity

Toroweap Formation (interfingers with White Rim Sandstone)

Area of Reservoir: 150 km^2
Average Depth: 787 m
Lithology of Reservoir: dolomite with interbedded sandstone and shale, Permian Toroweap Formation
Net Thickness: 120 m
Lithology of Seal: shale and impermeable carbonates (within the Permian Toroweap Formation)
Gas Composition (co-mingled with other formations): see Cedar Mesa Sandstone reservoir
Production History: none
Porosity-Permeability Characteristics: 6-8% porosity (permeability is unknown), intercrystalline and fracture porosity

White Rim Sandstone (interfingers with Toroweap Formation)
Area of Reservoir: 150 km^2
Average Depth: 787 m
Lithology of Reservoir: Permian White Rim Sandstone
Net Thickness: 120 m
Lithology of Seal: dolomite (Permian Kaibab Limestone)
Gas Composition (co-mingled with other formations): see Cedar Mesa Sandstone reservoir
Production History: none
Porosity-Permeability Characteristics: 6-8% porosity (permeability is unknown), intergranular and fracture porosity

Kaibab Limestone
Area of Reservoir: 150 km^2
Average Depth: 720 m
Lithology of Reservoir: limestone and dolomite, Permian Kaibab Limestone
Net Thickness: 85 m
Lithology of Seal: TR-unconformity and impermeable carbonates (within the Permian Kaibab Limestone and Timpoweap Member of the Triassic Moenkopi Formation)
Gas Composition (co-mingled with other formations): see Cedar Mesa Sandstone reservoir
Production History: none
Porosity-Permeability Characteristics: 6-8% porosity (permeability is unknown), intercrystalline and fracture porosity

Timpoweap Member of the Moenkopi Formation
Area of Reservoir: 150 km^2
Average Depth: 691 m
Lithology of Reservoir: limestone and dolomite with interbedded siltstone, Timpoweap Member of the Triassic Moenkopi Formation
Net Thickness: 25 m
Lithology of Seal: shale (upper member of the Moenkopi Formation)
Gas Composition (co-mingled with other formations): see Cedar Mesa Sandstone reservoir
Production History: none
Porosity-Permeability Characteristics: 4-5% porosity (permeability is unknown), intercrystaline, fracture porosity

Shinarump Member of the Chinle Formation
Area of Reservoir: 150 km^2
Average Depth: 418 m
Lithology of Reservoir: coarse-grained sandstone, Shinarump Member of the Triassic Chinle Formation
Net Thickness: 69 m
Lithology of Seal: shale (upper member Chinle Formation)
Gas Composition (co-mingled with other formations): see Cedar Mesa Sandstone reservoir
Production History: none

Porosity-Permeability Characteristics: 4-8% porosity (permeability is unknown), intergranular and fracture porosity
Additional Comments: Escalante field was discovered in 1960 when Phillips Petroleum drilled and tested carbon dioxide gas from the Escalante Unit No. 1 well (section 32, T. 32 S. R. 3 E., Salt Lake Base Line & Meridian [SLBL&M]). However, the completion of this well and two later wells were plagued by mechanical problems even though tests of the Permian and Triassic sections flowed carbon dioxide at high rates. In 1983, Mid-Continent Oil and Gas Reserves, Inc., successfully drilled the No. 1 Charger 1 well (section 29, T. 32 S. R. 3 E., SLBL&M) to a total depth of 1,050 m. The well test had a total open flow gauged at 3.5 million m^3 (124 MMCF) of gas per day from a net productive Permian and Triassic section of 600 m. The high flow rate from this section suggests the presence of extensive fracturing in the relatively shallow part of the field.

The Permian and Triassic carbon dioxide reservoirs in Escalante field represent numerous rock types deposited in a variety of environments. The Permian Cedar Mesa and White Rim Sandstones represent nearshore beach to dune deposits and are composed of porous, cross-bedded, fine- to medium-grained sandstone. In between these units is the Toroweap Formation, deposited in and adjacent to a shallow sea. The Toroweap consists of very fine to fine-grained dolomite interbedded with thin, fine- to medium-grained sandstone and shale. The Permian Kaibab Limestone was also deposited in a widespread shallow sea. The Kaibab consists of very fine to fine-grained limestone and dolomite with thin interbedded sandstone and shale. The Triassic Timpoweap Member of the Moenkopi is a fine-grained, dense carbonate deposited in a near-shore marine environment. The Shinarump Member of the Triassic Chinle Formation was deposited by northwest-flowing steams in a river flood plain. The Shinarump consists of porous, medium- to coarse-grained sandstone.

The trap is a large, asymmetrical (steepest dips on the west flank), north- to northwest-trending anticline located in the northernmost part of the Kaiparowits basin. It is one of many gentle, secondary folds of this Laramide-age structural basin. Most of these folds developed over deep faults in Precambrian basement rocks. The Escalante structure is approximately 32 km long and 3 km wide with 600 m of closure. There are three subsidiary closures along the axis of the anticline, the northern closure being structurally highest. Limited seismic data suggest a possible north-south fault along the east flank of the structure although it does not offset the Jurassic Navajo Sandstone, which is exposed on the surface of the anticline. However, the Navajo does display numerous joint and fracture patterns oriented in various directions.

Unlike other Utah carbon dioxide deposits, one potential cause and source for the gas in the Escalante anticline is nearby and relatively obvious – igneous intrusions associated with the High Plateaus volcanic province interacting with the thick carbonate section of Paleozoic rocks just to the north of the structure. Extensive Tertiary volcanic rocks covering large areas of the High Plateaus and parts of the Kaiparowits basin implies intrusions of high-level Tertiary plutons. These plutons probably acted as heat sources. The modern heat flow in the region ranges from 60-100 mWm^{-2}. Metamorphism of marine carbonates by the heat of igneous intrusive rocks likely generated high concentrations of carbon dioxide. Carbon dioxide may also have been produced by the reaction of hot, acidized ground water (heated by the igneous intrusions) with the carbonate rocks or kerogen-bearing (source) rocks. Another possible source of carbon dioxide is a deep-seated volcanic source with the gas migrating along faults and fractures at the time of intrusion. Wells drilled on other structures in the region have tested carbon dioxide but in general, the farther away from the High Plateaus volcanic province, the lower concentrations of carbon dioxide in the recovered gases. This suggests a southerly migration of carbon dioxide.

There has been no production of carbon dioxide from Escalante field due to environmental issues, the lack of a pipeline, and no market for the gas. However, carbon dioxide reserves in the field were initially estimated to be as high as 43 to 113 billion m^3 (1.5 - 4 TCF) of gas – the largest deposit in Utah.

References: Anderson et al. (2000), Blakey and Gubitosa (1983), Bryant (1987), Campbell (1978), Chidsey, (1997), Chidsey and Morgan (1993), Chidsey et al. (1998), Doelling (1975), Doelling and Davis (1989), Hintze (1993), Moore and Sigler (1987), Petroleum Information (1984).

McElmo Dome, Colorado

Area: 800 km^2
Average Depth: 2100 m
Reservoir Lithology: Mississippian Leadville Limestone (the reservoir is actually dolomite)
Net Thickness: 21 m
Gross Thickness: 90 m
Seal Lithology: Paradox salt (Pennsylvanian)
Gas Composition: CO_2 98.2%, N_2 1.6%, CH_4 0.2%
Porosity and Permeability: porous zones are continuous but variable in thickness; porosity ranges from 3 – 20%, averaging 11%. The continuity of the CO_2-water contact dipping at 0.5^o to the west suggests most of the reservoir has reasonable to good permeability. Permeabilities from well tests average 23 mD; but core measurements range up to 200 mD.
Production History: Has produced at between 6.2 – 8.8 billion m^3 (220 and 315 BCF/Y) since 1995. Total cumulative production is 92 billion m^3 (3.3 TCF, through 1999). Discovery was in 1948, and subsequently gas was produced for a CO_2 plant. Large-scale flows to West Texas began in 1982.
Reservoir Water Chemistry (mg/kg): Total dissolved solids 27,000 – 44,000, Na 8,500 – 14,000, Ca 800 – 1900, Mg 130 – 400, Total Fe 70 – 135, Cl 11,000 – 23,000, HCO_3 3,300 – 3,900, SO_4 1,400 – 1,900.
Total Reserves: 476 billion m^3 (17 TCF)
Additional Comments: CO_2 accumulation occurs in a northwest-plunging anticlinal structure. Dip on CO_2-water contact thought to reflect regional hydrologic gradient. Corrosion of steel casing has been a problem, but newer wells are equipped with special casing and tubing.
References:
Gerling (1983); Tremain (1993).

Sheep Mountain, Colorado

Area: 20 km^2
Average Depth: 1500 m

Reservoir Lithology: Dakota and Entrada massive-bedded sandstone
Gross Thickness: 150 m
Seal Lithology: Cretaceous marine sediments; these are capped by a laccolith
Gas Composition: CO_2 97%, N_2 0.6%, CH_4 1.7%
Porosity and Permeability: No information. Reservoir is a northwest-trending anticlinal fold, bounded on its northeast side by a thrust fault.
Total Reserves: estimated to be 70 billion m^3 (2.5 TCF).
Production History: Production began in 1983, and has continued at a rate of approximately 2 billion m^3/year (70 BCF/year) since then. Total cumulative production is 34 billion m^3 (1.2 TCF; through 1999). The gas is piped to West Texas.
Additional comments: Another CO_2 reservoir (Dike Mountain) occurs 15 km south of Sheep Mountain anticline. It has not been developed, and apparently contains gas with 80% CO_2.
References:
Roth (1983); Tremain (1993).

Bravo Dome, New Mexico

Area: 2000 km^2
Average Depth: 700 m
Reservoir Lithology: The primary producing zone (99% of CO_2) is Permian Sangre de Cristo (Tubb) arkosic to conglomeratic sandstone. Secondary production comes from Triassic Santa Rosa sandstone. The Tubb sandstones were deposited in an arid, eolian environment.
Average Net Thickness: 30 m
Seal Lithology: Cimarron anhydrite over the main production zone; Chinle mudstone over the upper, secondary zone. Trap formed by structural closure on three sides, and facies change to mudstone on the northwest boundary.
Gas Composition: CO_2 99%, N_2 minor, trace noble gases
Porosity and Permeability: 20% average porosity, 42 mD average permeability
Total Reserves: estimated to be 450 billion m^3 (16 TCF).
Production History: Field was discovered in 1916, and after 1931 was produced at < 1 BCF/Y for dry ice and bottled liquid. In 1983, Bravo Dome was expanded greatly (270 wells) and the gas was connected into the Sheep Mountain pipeline to West Texas for enhanced oil recovery. Average production rate was 3.4 billion m^3 (120 BCF/year). Total cumulative production (1999) is estimated at 53 billion m^3 (1.9 TCF).
Additional Comments: Ownership changed from BP Amoco to Occidental in 2000. Plastic liners are used inside casing to prevent corrosion.
References:
Johnson (1983); Pearce et al. (1996); Tremain (1993).

Springerville, Arizona

Area: approximately 25 km^2
Average Depth: 600 m
Reservoir Lithology: Variable, in Permian red-bed clastics, carbonates, granite wash, and the underlying fractured basement granite.

Average Net Thickness: Gross thickness is at least 100 m, but only a few zones produce in any well.
Seal Lithology: Variable, comprising impermeable anhydrite beds in the upper part of the Permian sequence, and mudstones in the lower part. The trap is formed by a broad, asymmetrical anticline that is faulted on its southwest flank. Significant faulting occurs in the granite basement beneath the anticline.
Gas Composition: CO_2 90%, N_2 5 - 10%, He 0.5 – 0.8%; composition varies laterally
Porosity and Permeability: Both highly variable depending on lithology and other factors. Core porosities and permeabilities range up to 20% and to over 100 mD, respectively.
Production History: Was discovered in a 300 m-deep well in 1959, which was estimated to produce 70,000 m^3/day (2.5 MMCF/D). Subsequent producers were mostly drilled between 1994 and 1998. No field-wide production yet. Reported well tests range up to 56,000 m^3/day (2 MMCF/D). In 1999 it was reported that a gas processing plant would be built to separate and market the helium, while injecting the CO_2 until markets were developed.
Additional Comments: Several of the wells had problems with water entering the open sections in addition to gas. Corrosion of the steel casing has occurred, requiring the use of fiberglass liners.
References:
Rauzi, (1999a); Rauzi (1999b).