

Appendix C
Technical Feasibility of CO₂ Sequestration



**TECHNICAL FEASIBILITY
CARBON DIOXIDE
SEQUESTRATION OPTIONS
MOHAVE GENERATING
STATION**

**For: Sargent & Lundy Engineers,
Ltd**

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ABBREVIATIONS AND ACRONYMS

API	American Petroleum Institute
AZGS	Arizona Geological Survey
bbbl	Barrel
bgs	Below ground surface
CBM	Coal bed methane
CO ₂	Carbon dioxide
CO ₂ -ECBM	Carbon dioxide enhanced coal bed methane recovery
CO ₂ -EOR	Carbon dioxide enhanced oil recovery
DOE	Department of Energy
ECBM	Enhanced coal bed methane
EOR	Enhanced oil recovery
GHG	Greenhouse Gas
IGCC	Integrated Coal Gasification/Combined Cycle
LLNL	Lawrence Livermore National Laboratory
Mscf	Thousand standard cubic feet
MMP	Minimum miscibility pressure
MW	Megawatt
NETL	National Energy Technology Laboratory
NGCC	Natural Gas-Fired/Combined Cycle
OOIP	Original oil in place
ORISE	Oak Ridge Institute for Science and Education
PC	Pulverized coal
ppm	Parts per million
psig	pounds per square inch gauge
PWCC	Peabody Western Coal Company
PUC	California Public Utilities Commission
SCE	Southern California Edison
S&L	Sargent & Lundy
Tcf	Trillion cubic feet
TDS	Total dissolved solids
TBEG	Texas Bureau of Economic Geology



1.0 INTRODUCTION

Southern California Edison's (SCE's) Mohave Generating Station is a coal-fired facility located in Laughlin, Nevada. The Black Mesa Mine complex consists of two open pit mines operated by Peabody Western Coal Company (PWCC): the Kayenta Mine, which supplies coal to the Navajo generating station in Page, Arizona, via an 83-mile-long electric railroad; and the Black Mesa Mine, which supplies coal via a buried slurry pipeline to the Mohave Generating Station. The station is some 300 miles from the numerous oil fields in Bakersfield, Kern County, California.

In recent years, numerous studies have been undertaken by various entities to evaluate the removal of greenhouse gas (GHG) from the atmosphere and sequestration of carbon compounds in the subsurface using a variety of technologies. Key participants in these studies include: U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL); Lawrence Livermore National Laboratory (LLNL); Texas Bureau of Economic Geology (TBEG); Sandia National Laboratory; Los Alamos National Laboratory; Oak Ridge Institute for Science and Education (ORISE); the U.S. Geological Survey, and state geological surveys in Pennsylvania, West Virginia, and Illinois; universities, such as Petroleum Technology Research Centre at the University of Regina, Saskatchewan, Pennsylvania State University, Columbia University, Ohio State University, University of Texas at Austin, West Virginia University, and Case Western Reserve University; and industry.

Several pilot projects have been undertaken by researchers and industry, and a few carbon dioxide (CO₂) sequestration projects are operational and have been for several years, such as the Sleipner West natural gas field under the North Sea, and the Weyburn oil field in Saskatchewan, Canada.

Five different types of geologic reservoirs are considered suitable for storing carbon: depleted oil and gas fields; unmineable coal seams; saline aquifers; oil shales; and mafic rock (Friedmann, 2003). This study is directed toward evaluation of the first three.



2.0 OBJECTIVES AND SCOPE OF WORK

Sargent & Lundy (S&L) was retained by SCE to explore the feasibility of various alternatives or complements to the existing Mohave Generating Station, as directed by the California Public Utilities Commission (PUC). Included in this scope was an evaluation of the feasibility of CO₂ sequestration from Integrated Coal Gasification/Combined Cycle (IGCC) or Natural Gas-Fired/Combined Cycle (NGCC) plants located at the existing site, and an IGCC plant located at the Black Mesa Mine site.

The objective of URS' consultation with S&L was to conduct a review of readily accessible literature in order to provide sufficient data for the following evaluation of sequestration options:

1. An evaluation and opinion regarding the feasibility of enhanced oil recovery through CO₂ injection at oil fields in Bakersfield, California; and
2. Identification of a suitable geologic formation for sequestration of CO₂ in the area of the Black Mesa Mine site in Arizona.

In order to achieve the stated objectives, URS has conducted the following scope of work:

- Collection and synthesis of recent available relevant technical literature in the public domain.
- Review of collected data for CO₂-enhanced oil recovery (EOR) and CO₂ sequestration and enhanced coal bed methane (ECBM) recovery.
- Interviews with appropriate researchers from government agencies, national laboratories, universities, and recognized authorities in the study of carbon sequestration in the private sector.
- Preparation of a report detailing the technical feasibility of the sequestration options evaluated.

3.0 BAKERSFIELD CO₂ – ENHANCED OIL RECOVERY

CO₂ has been injected into depleted oil fields to recover additional oil since the early 1970s, and CO₂ flooding is one of several technologies used by the oil industry to complete what is known as enhanced oil recovery (EOR). In the year 2000, a total of 84 commercial or pilot-scale EOR projects using CO₂ injection were operational worldwide. Of these 84 projects, 72 were operating in the U.S., and the majority of these were operating in the Permian Basin in west Texas and New Mexico.

A small proportion of oil, typically 20 to 40 percent of the original oil in place (OOIP), is recovered from oil reservoirs using traditional methods of recovery. EOR methods, including CO₂ injection, can allow for recovery of another increment of the OOIP.

A recent report completed by the DOE indicates that the OOIP in 172 of California's largest oil reservoirs equates to an estimated 83 billion barrels (DOE, 2005). Only 26 billion barrels of oil have been recovered or proved (will be recovered) from these fields to date. It is estimated that approximately 57 billion barrels of the OOIP will be remain in place without use of EOR methods, including CO₂ flooding.

A DOE study (DOE, 2005) concluded that an additional 1.7 to 3.8 billion barrels of oil may be recovered in California using miscible CO₂ flooding techniques. These estimates are based on \$35 per barrel (bbl) oil prices and CO₂ costs of \$0.50 to \$1.25 per thousand standard cubic feet (Mscf).

The remainder of this section presents the following with regard to CO₂-EOR:

- CO₂-EOR processes;
- Screening of oil reservoirs in the San Joaquin Basin for CO₂ flooding;
- Sources of affordable CO₂;
- Transportation of CO₂;
- CO₂-EOR operations including “blow down” of the reservoir; and
- Long-term storage of CO₂ in petroleum reservoirs.

3.1 CO₂-EOR PROCESSES

CO₂-EOR can be used for miscible or immiscible oil recovery. Miscible CO₂-EOR has been the primary process used on commercial CO₂-EOR projects in the U.S. Miscible CO₂-EOR projects are implemented in oil reservoirs that contain light crude oil (crude oil that has an American Petroleum Institute (API) gravity of greater than 25 degrees), and at depths of at least 3,000 feet



below ground surface (bgs). These conditions are required to achieve the minimum miscibility pressure (MMP) for the CO₂ and oil in the reservoir. A schematic illustration of the CO₂-EOR process is presented as Figure 1. The amount of oil recovered by miscible CO₂-EOR is dependent upon reservoir-specific characteristics, but can range from 10 to 15 percent of the OOIP.

The CO₂ that is used to initiate miscible floods must be greater than 95 percent CO₂. Nitrogen content in the CO₂ will affect the ability to achieve the MMP in a candidate petroleum reservoir, and will also increase the costs of compression and transport of CO₂.

CO₂-EOR projects can also be designed for immiscible applications. Immiscible projects can be applied to oil reservoirs that are shallower than 3,000 feet or on crude oils that are heavier (have an API gravity of less than 25 degrees). The MMP is not achieved in an immiscible process. Substantial incremental oil can be recovered from depleted oil reservoirs using immiscible CO₂-EOR.

3.2 SCREENING OF OIL RESERVOIRS IN THE SAN JOAQUIN BASIN FOR CO₂ FLOODING

Several large oil fields are present in the San Joaquin Basin in the vicinity of Bakersfield. The DOE (2005) identified 24 oil reservoirs within the San Joaquin Basin that may be technically and financially feasible for miscible CO₂-EOR projects. The largest fields that satisfy screening criteria for miscible CO₂-EOR, shown on Figure 2, include:

Field Name	Reservoir Name	Depth (Feet)	Oil Gravity (Degrees API)	Remaining Oil in Place (MM Bbls)
Elk Hills	Stevens	5,500	35	1,557
Coalinga, E. Extension	Nose Area	7,800	30	464
Kettleman, N. Dome	Temblor	8,000	36	891
Cuyama S.	Homan	4,000	32	605

Source: U.S. Department of Energy (2005)

Three other basins within California have also been identified as containing oil reservoirs with potential for CO₂-EOR, including the Los Angeles Basin, the Ventura Basin, and the Santa Rosa Basin.



Recent increases in world crude oil prices will result in improved economics for recovery of oil via CO₂-EOR and renewed efforts to implement enhanced oil recovery in California's oil fields, especially the larger fields.

3.3 SOURCES OF AFFORDABLE CO₂

A primary barrier for use of CO₂-EOR in California's oil fields has been lack of a secure and sufficient source of affordable CO₂. Carbon dioxide suppliers have reported that availability of CO₂ is currently limited. Additional natural and anthropogenic sources of CO₂ are available to be developed, but a substantial lead time of years will be required to construct the production and pipeline infrastructure to increase supplies to California oil fields.

Natural sources of CO₂ include reservoirs discovered and developed in Colorado, Arizona, or New Mexico. Local California sources include refineries, where CO₂ is produced in hydrogen plants. Pipelines are required to economically transport the CO₂ from these various sources to oil fields. The pipeline infrastructure required for transportation does not yet exist. Currently, it does not appear that economics justify construction of a pipeline to California from the developed natural resources in Colorado, New Mexico, and Arizona.

The long-term reliability of the refinery sources has been identified as a barrier to construction of pipeline infrastructure from the Wilmington refineries (in Southern California) to candidate reservoirs in the San Joaquin Basin (Friedmann, 2005; Personal Communication). Reliability of refineries as a long-term source of CO₂ may be affected by the economics of continued operation of the refinery and the continued use of specific refining processes that generate CO₂ as a by-product in the refinery. The recent increase in crude oil prices to approximately \$60/bbl will accelerate the construction of the pipeline infrastructure for use of the identified sources of CO₂. The timeframe for construction is still uncertain.

Potential future sources of CO₂ include fossil-fuel-fired electric power plants. A 1,000-megawatt (MW) pulverized coal (PC) power plant emits between 6 and 8 million tons of CO₂ per year (Herzog, 2004). Currently, the best technology for removing CO₂ from stack gas is absorption using diethanolamine scrubbers. One example of CO₂ recovery at a coal-fired power plant is the Warrior Run plant, located in Maryland, where 150 tons per day of CO₂ are recovered (Thambimuthu, 2002). The cost of CO₂ recovered from electric power plants in this manner is currently more expensive than CO₂ produced from natural sources. Future technical developments may decrease costs and improve the economics of recovering CO₂ from fossil-fuel-fired power plants for use in CO₂-EOR projects. No technical developments are foreseen that will allow for competitively priced anthropogenic CO₂ for EOR projects when compared to the cost of natural sources of CO₂ (Leppen, 2005; Personal Communication).



The overall market for CO₂ in California for CO₂-EOR has been estimated to be 18 trillion cubic feet [Tcf] (DOE, 2005). Much of this CO₂ will be recycled and reused after delivery to the regional market. CO₂ will be recovered and recycled after being injected either into the oil reservoir where it was originally injected or into another oil reservoir in the region.

The potential development of both natural and anthropogenic sources of CO₂ for use in California EOR projects remains uncertain. Increased world oil prices will drive new efforts to develop both supplies of CO₂ and EOR projects that may use those supplies.

3.4 TRANSPORTATION OF CO₂

CO₂ is usually transported as a compressed fluid in a supercritical phase where it behaves like a liquid with respect to density, but like a gas with respect to viscosity. The supercritical fluid is typically delivered to users in a mixture that is greater than 95 percent CO₂ and at pressures of approximately 1,500 pounds per square inch gauge (psig). The cost of transportation is substantial, and depends on construction of a regional pipeline or trunk line from the source to the location of use. This includes the use of compressor stations to maintain the CO₂ in a supercritical phase.

3.5 CO₂-EOR OPERATIONS INCLUDING “BLOW DOWN” OF THE RESERVOIR

Gases from CO₂-EOR projects are recovered and recycled into the oil reservoir during operation of the project. A typical project may operate from 10 to 30 years. Incremental oil may be recovered at the end of the project by “blowing down” the reservoir. During a “blow down,” the reservoir is slowly depressurized. Gases produced during the “blow down” may be compressed and transported to another CO₂-EOR project in the region, or they may be vented to the atmosphere.

A CO₂-EOR program was recently implemented in the Weyburn Field, located on the northern end of the Williston Basin in Saskatchewan, Canada (Torp, 2003). The project has been designed to be operated with no “blow down” of the reservoir at the conclusion of the program. The Weyburn program includes a long-term study to demonstrate that the CO₂ injected there will remain in the reservoir for long time periods equivalent to geologic timescales.

3.6 LONG-TERM STORAGE OF CO₂ IN PETROLEUM RESERVOIRS

The length of time that CO₂ can be isolated in a petroleum reservoir is being studied by a variety of organizations. The DOE is providing funding to seven regional partnerships to develop and



evaluate technologies for carbon, including CO₂ sequestration. Participants in the partnerships include universities, government agencies, Indian nations, and businesses.

The West Coast Regional Carbon Sequestration Partnership, lead by the California Energy Commission, is planning to conduct two projects in California and one project in Arizona to demonstrate and evaluate CO₂ storage in depleted gas reservoirs and other subsurface formations.

Weyburn is the first CO₂-EOR project to include a long-term study to demonstrate effective geologic isolation of CO₂ in a petroleum reservoir. Other operations that are valid analogs for evaluation of long-term sequestration of gases in petroleum reservoirs include acid gas injection projects, when the acid gas is produced from petroleum reservoirs as hydrogen sulfide and other related organic sulfur compounds. Acid gas injection has been implemented by petroleum producers since the 1970s.

3.7 SUMMARY

CO₂ sequestration via EOR has proven to be a viable technology. Furthermore, there are existing oil fields in the vicinity of Bakersfield, California that would be appropriate for CO₂ flooding. However, the EOR process requires a relatively pure source of CO₂, necessitating the treatment of flue gases from coal-burning power plants. This, coupled with the need for suitable CO₂ transportation via a pipeline, makes this sequestration option prohibitively expensive at this time. In fact, the reason that a pipeline to convey CO₂ to the Bakersfield area has not yet been built is because it has not been financially attractive to industry. However, the financial viability of this process will be significantly influenced by the price of oil, which is currently in a state of flux.

A variation of the use of CO₂ for EOR purposes is the sequestration of CO₂ in naturally occurring reservoirs which form the source of CO₂ for other applications, in essence a recycling of the resource. This possibility was evaluated (Allis, et al., 2001) for reservoirs on the Colorado Plateau and in the southern Rocky Mountains. About ten natural CO₂ fields in this region have been tapped for some time as a source of CO₂-EOR. Ultimate sequestration of CO₂ back into one or more of these reservoirs would depend upon the potential for trapping of the CO₂ in the subsurface, e.g., minimal leakage to the surface, as well as economic considerations. Gas storage options and an evaluation of possible leakage is being conducted. The economic viability of this option would depend upon the infrastructure required, as well as the willingness of the field operator to accept the CO₂ for injection back into the field, which is unknown at this time.

4.0 BLACK MESA CO₂ SEQUESTRATION

CO₂ sequestration refers to the long-term storage of CO₂, generally on the order of thousands of years. As the idea of CO₂ sequestration in geologic receptors gained interest, many types of geologic rock bodies, called formations, were examined as potential hosts for CO₂ generated by man-made processes. Host geologic formations considered for CO₂ sequestration include oil and/or gas reservoirs, deep saline formations, deep unmineable coal deposits, massive dome-shaped salt features and bedded salt formations, coal-bearing shales, and even dark-colored magnesium-rich silicate (mafic) rocks that are low in quartz.

Two types of geologic formations were immediately recognized for the value-added economic benefits that could be realized by CO₂ injection and sequestration: enhanced oil and/or gas recovery in depleted or depleting oil and/or gas reservoirs (CO₂-EOR), and enhanced coal-bed methane recovery in deep unmineable coal deposits (CO₂-ECBM). Opportunities for CO₂-EOR in oil reservoirs were discussed earlier in this report. This section focuses on deep saline formations and deep CO₂-ECBM.

4.1 SCREENING CRITERIA FOR GEOLOGIC FORMATIONS

Various researchers have developed physical, chemical and economic criteria to screen geologic formations suitable for CO₂ sequestration (Stevens et al., 1999; Frailey et al., 2005; White et al., 2003; Herzog and Golomb, 2004; GEO-SEQ, 2004; UTBEG, 2005). This section will evaluate the suitability of geologic formations for CO₂ sequestration based on the following physical and chemical criteria:

- Sequestration must occur at depths greater than approximately 800 meters (2,620 feet), which places CO₂ above its critical point. The critical temperature at which CO₂ exists as a dense gas is 304°K (88°F) (White et al., 2003). At that temperature, CO₂ is a gas with such high density that it cannot mix with formation fluids. Furthermore, under these conditions it is less viscous than the surrounding brine, so it behaves as a gas compared to the brine (GEO-SEQ, 2004).
- A maximum depth of 2,000 meters (6,560 feet) is suggested to limit the required wellhead injection pressure, and also cap the cost to drill an injection well (Allis et al., 2003).
- The storage capability of the formation must be prolonged for hundreds to thousands of years. The overlying formation, or cap rock, that seals in the CO₂

must be thick and impermeable to gas. The structural integrity of the formation and the horizontal extent of the formation must be intact; no large faults, structural breaches, or outcrops can exist as pathways that allow CO₂ to escape from the formation.

- Sequestration must target porous formations having saline fluids that generally feature greater than 3,000 parts per million (ppm) total dissolved solids (TDS). Porous water-bearing formations (aquifers) that contain fresh water are economically valuable sources of water for domestic, agricultural, and industrial uses. Conversely, saline water has no economic value, and as a result, porous saline formations are suitable hosts for CO₂ sequestration.

4.2 SUITABLE GEOLOGIC FORMATION TYPES

4.2.1 Deep Saline Formations

Characteristics

The ideal deep saline formation target for CO₂ sequestration is a thick, laterally continuous and relatively homogeneous sandstone or carbonate (limestones and dolomites) with high porosity and permeability. The advantages of deep saline formations include:

- Generally high porosity and moderate to high permeability for sandstones, and moderate porosity and permeability for carbonates—the high porosity in a thick formation provides a large capacity for CO₂ storage, and moderate permeability reduces the potential for clogging the narrow passageways connecting pore spaces by precipitation of carbonate minerals.
- The depth and high salinity result in few competing uses for the formation (GEO-SEQ, 2004).
- Deep, laterally extensive formations provide a long, slow flow path for CO₂ migration back to the biosphere.
- CO₂ is less dense than the saline formation fluid and will rise to the top of the formation like a gas cap (Benson, 2003).

The disadvantages of deep saline formations are a result of their depth and lack of economic value:

- Deep saline formations are not well characterized because they are not targets for oil and gas exploration and little or no reservoir characterization has been completed (Orr, 2003).
- The thickness and quality of the cap rock or seal may be unknown.
- Monitoring of the CO₂ injection and migration, and fluid/rock interaction processes will be difficult at depth because monitor wells are expensive to install and other monitoring methods have less resolution at depth.

Sequestration in deep saline formations has been proven effective in Statoil's Sleipner West Field in the North Sea. The CO₂ is separated from gas production and injected in the Utsira sandstone formation using a horizontal well. The horizontal well is used to avoid corrosion by CO₂ of adjacent wells by directing the CO₂ away from those wells. The project began in 1996 and stores CO₂ at a depth of 1,000 meters (3,280 feet) in the sandstone, which is 15 to 75 meters (50 to 250 feet) thick. About 2,800 tons of CO₂ are injected into the formation each day (Torp and Brown, 2003).

Trapping Mechanisms

There are three processes for long-term CO₂ trapping in saline formations (Herzog and Golomb, 2004; White et al., 2003): hydrodynamic, solution, and mineral. Each process is discussed below.

Hydrodynamic – Saline formations need an impermeable cap rock to seal in the CO₂, which is less dense than the brine. This will force the CO₂ to become entrained in the groundwater and trapped hydrodynamically. The CO₂ moves away from the well under the influence of the injection pressure, but eventually migrates outside the influence of the well and flows with the natural hydraulic gradient. This may occur within a few kilometers of the injection well.

Solution – CO₂ also can be trapped by dissolution into the brine. Dissolved CO₂ is not subject to buoyancy and is not so dependent on the cap rock for trapping. Injection of CO₂ lowers the pH of the formation brine and increases mineral dissolution in sandstone formations. Mineral dissolution has a buffering effect that increases the solubility of CO₂ in the brine. This buffering effect does not occur in carbonate formations because dissolution of the mineral matrix does not increase the solubility of CO₂ or solution trapping.

Mineral – Mineral trapping occurs when CO₂ reacts with minerals present in the formation rock to form stable solids that are not subject to leaking. Mineral trapping is prevalent where +2



valence ions such as Mg^{2+} , Ca^{2+} , and Fe^{2+} are present to precipitate magnesium, calcium, and/or iron carbonates, respectively.

There is, however, a tradeoff in the effectiveness of mineral trapping. If the mineral trapping occurs early in the life of the injection near the injection well, passageways between the pores will clog and severely reduce the permeability and effective storage capacity of the formation. White et al. (2003) envisions a cyclical process of precipitation and re-dissolution in saline formations, as well as in coal seams. They hypothesize that the drop in CO_2 partial pressure as the CO_2 moves away from the injection well will cause mineral precipitation and permeability reduction. The reduction in permeability will cause the partial pressure of CO_2 to increase and re-dissolve the precipitated minerals, opening pore spaces for increased CO_2 movement away from the injection well. This cyclical process could continue until CO_2 equilibrates with the formation and is neutralized, or until CO_2 contacts the low pressure at a gas production well and forms carbonate scale in the well casing.

Formations Near Black Mesa Mine

This study identified and evaluated geologic formations in the Black Mesa Mine area suitable for CO_2 sequestration. A geologic report prepared by Peabody Coal Company (Peabody, 2004) mapped the sedimentary formations underlying the Black Mesa Mine. The deep formations include thick, porous sandstones such as the Wingate, Coconino, De Chelly, and Cedar Mesa Sandstones; and thick porous carbonates such as the Redwall and Muav Limestones. Formations found suitable for CO_2 sequestration include the Coconino Sandstone and Redwall Limestone.

Sandstones – Although there are no reported deep saline formations beneath the Black Mesa Mine, a suitable saline formation is located approximately 72 kilometers (45 miles) south of the mine. Peabody (2004) mapped the sedimentary formations underlying the mine. The deep, thick sandstones include the Wingate, Coconino, De Chelly, and Cedar Mesa Sandstones. Unfortunately, those sandstone formations contain fresh water in the immediate vicinity of the mine (Robson and Banks, 1995). However, the Permian-age Coconino Sandstone does have a region of high salinity south of the mine, where salinity ranges from 3,000 to more than 25,000 ppm (Figure 3). In this area, the Coconino Sandstone is 2,500 to 3,500 feet deep, from 500 to 800 feet thick, has moderate to high porosity, and is in a geologically stable area with little faulting or folding. The high salinity aquifer encompasses an area approximately 50 miles long and 20 miles wide. This formation dips upward and thins to the south away from Black Mesa.

URS contacted Steven L. Rauzi, Oil and Gas Administrator at the Arizona Geological Survey (AZGS). As a member of the Southwest Region Geological Sequestration Partnership, the

AZGS conducted an inventory of formations that may be suitable for CO₂ sequestration near coal-fired power plants in northern Arizona. The AZGS recognized the Coconino Sandstone as a suitable sink for CO₂ in northern Arizona (Mahan, 2005). This area is within the Navajo and Hopi Indian Reservations, and permitting for an injection well will require their approval. State agencies (Arizona Department of Water Resources; Arizona Department of Environmental Quality) also would require an aquifer protection permit to inject CO₂ into deep saline formations.

Limestones – The Mississippian-age Redwall Limestone also was recognized as a good candidate formation in northern Arizona for CO₂ sequestration (Allis et al., 2003; Mahan, 2005). The Redwall Limestone is a thick, massive dolomite (calcium magnesium carbonate) and dolomitic limestone at sufficient depth for CO₂ to reach the critical point. Variations in reservoir porosity can result from depositional environment changes and/or recrystallization of carbonate minerals that have enhanced porosity. In the Grand Canyon, 114 kilometers (70 miles) west of Black Mesa, Redwall Limestone outcrops display large, cavernous dissolution features, confirming that high porosity can be present (Utah Geological Survey, 2003). Regional and local structures have relatively gentle dips, and faulting is not extensive (Peabody, 2004). Thick shale in the Permian Organ Rock Formation provides an effective cap rock. The geologic structure beneath Black Mesa resulted in deposition of a thick Redwall Limestone section.

There is, however, limited information on the groundwater quality in the Redwall Limestone. A wireline geophysical log was run in the Sinclair #1 Navajo well, located 30 miles west of the Black Mesa Mine. The log response indicates that the upper 280 feet of the Redwall are limestone and contains fresh formation water. The lower 140 feet are mostly dolomite and contain saline formation water. Saline water also is present in a dolomitic zone in the upper 65 feet of Muav Limestone below the Redwall. Water samples collected from Redwall-Muav springs in Grand Canyon, 114 kilometers (70 miles) west of Black Mesa, contained fresh water (Monroe et al., 2004).

URS interviewed James A. Drahovzal at the Kentucky Geological Survey, who has studied deep carbonate reservoirs for CO₂ sequestration. He agrees that carbonate formations are generally not well characterized both for storage capacity and formation salinity, and that greater emphasis should be placed on evaluating deep carbonate reservoirs for CO₂ sequestration. Carbonate reservoirs also should be good candidates for sequestration because the CO₂-carbonate fluid-rock interactions will not have a significant impact on reservoir porosity and permeability.

Alluvial Aquifers – Deep sand and gravel (alluvial) basins contain aquifers near the Arizona-California border. There can be a wide variation in aquifer salinity in these formations, and most of the deep aquifers have not been penetrated or tested at the depth necessary for CO₂

sequestration. Robson and Banks (1995) reported that alluvial basins in the Mohave-Kingman area have groundwater with salinity generally less than 1,000 ppm. Beneath the shallow non-saline alluvial formations, deeper saline alluvial formations may exist that have not been tested.

URS contacted Steve Rauzi of the AZGS for information on deep alluvial aquifers. Because oil and gas exploration has not targeted those deep formations, there is no information on aquifer thickness and areal extent, and no groundwater quality data. If no suitable formations can be found for CO₂ sequestration near the Black Mesa Mine, exploration of deep alluvial aquifers near the Arizona-California border may be warranted.

4.2.2 Deep Unmineable Coal Deposits

Characteristics

The ideal coal deposit target for CO₂ sequestration contains thick, laterally extensive and deep unmineable coal seams that have already produced coal bed methane (CBM) by dewatering the formation. The application of CO₂ injection and sequestration to CBM production is a value-added benefit. CBM production combined with CO₂ injection and storage expands the use of a coal resource by providing multiple benefits: (1) increased methane recovery; (2) ECBM drainage of a resource area; and (3) long-term CO₂ storage (Stanton et al., 2001). The advantages of using deep unmineable coal deposits include:

- CO₂ displaces methane gas that is adsorbed within coal. This process releases methane gas to production, while at the same time capturing and storing CO₂. Depending on coal quality, two or more molecules of CO₂ are captured for each methane molecule displaced (Stanton et al., 2001).
- Coal cleats (small fractures in the coal seams) provide porosity and permeability in the coal seams and increase the capacity for CO₂ capture.
- CO₂ accelerates gas recovery. Higher injection rates often result in higher methane production.
- The injected gas can be a mixture of nitrogen (N₂) and CO₂, such as is found in smokestack (flue) gases, that need not be purified prior to injection (White et al., 2003). This advantage can significantly reduce the cost of separating and cleaning CO₂ from flue gases.

The disadvantages of using deep unmineable coal deposits include:

- A limited depth range of 800 to 1,600 meters (2,600 to 5,200 feet) for optimum performance of CO₂ injection. Below that depth, coal cleats begin to close up, reducing porosity (Stevens et al., 1999).
- Uncertain sensitivity of the coal seams to ECBM depending on the coal rank (purity). A sensitivity study by Reeves et al. (2004) concluded that ECBM is more favorable in higher rank coal seams that have lower permeability.
- With CO₂ injection there is a general decline in coal permeability and injectivity as coal cleats dry out and begin to close up (Klara et al., 2003).

Burlington Resources has been injecting CO₂ into CBM wells at their Allison Unit in southwestern Colorado since 1995. The CO₂ is obtained from a natural source and is technically not a CO₂ sequestration project, although it has proven the viability of the process by injecting more than 300,000 tons of CO₂. This ECBM operation has lost some injectivity over time because the coal swells when it is contacted by CO₂ (Klara et al., 2003).

Trapping Mechanisms

Very little is understood about what happens to CO₂ when it is injected into a coal seam. Most understanding of the trapping and reaction processes is theoretical and is being evaluated using models. The theory and understanding of these physical, chemical, and thermodynamic processes are complex, and at least 10 hypotheses have been formulated to develop models. The reader is referred to White et al. (2003) for a discussion of these hypotheses.

Formations Near Black Mesa Mine

There are no deep unmineable coal deposits near the Black Mesa Mine. The Black Mesa Mine strips coal from the shallow Cretaceous-age deposits of the Mesaverde Group (Nations et al., 2000). Unmineable coal seams in the Black Mesa Basin are found at depths less than approximately 330 meters (1,000 feet) and are too shallow for optimum CO₂ sequestration. In addition, the coal seams are generally thin and do not extend laterally for more than about 5 miles to outcrops at the edge of Black Mesa.

There are deep unmineable coal deposits in the San Juan Basin, which is located about 150 miles east of the mine in New Mexico. CBM production is from multiple thick coal seams in the Cretaceous-age Mesaverde Group (Fassett, 2000). The San Juan Basin has several thousand CBM production wells and is one of the most prolific CBM production areas in the world. ECBM is in the beginning stages in the San Juan Basin, and there are many opportunities for



CO₂ injection in multiple coal seams throughout the basin. At this time the basin is served by one CO₂ pipeline from a natural deposit in Colorado. There is the potential for piping CO₂ from another natural source located in the St. Johns area of east-central Arizona.

4.3 SUMMARY

There are no deep unmineable coal deposits near the Black Mesa Mine suitable for CO₂ sequestration. Accordingly, this option is not considered viable. However, the Coconino-DeChelly sandstone of the Black Mesa Basin, south of the Black Mesa Mine, seems to be an appropriate receptor for CO₂ sequestration in a deep saline aquifer. As mentioned above, additional subsurface exploration and testing would be required to verify this possibility.



5.0 LIMITATIONS

Professional opinions expressed herein are based upon a limited scope of work, review of readily available and relevant technical literature, and interviews with cognizant professionals, and should not be construed as legal opinions. Other interpretations are possible based on information not reviewed by URS.

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