Enhanced Oil Recovery Scoping Study

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REPORT SUMMARY

This scoping study provides an overview of enhanced oil recovery (EOR) in the United States. It is a comprehensive reference developed to help utilities and energy service providers focus their efforts on good business opportunities in this energy intensive business segment.

Background

In 1998, a total of about 707,000 barrels of oil per day (BOPD) was produced in the U.S. using EOR methods, accounting for about 12% of total national crude oil production. Thermal EOR (mostly steam and hot water drive and huff-and-puff operations) accounts for about 393,000 BOPD or about 7% of U.S. production, carbon dioxide (CO_2) EOR accounts for about 196,000 BOPD or about 3% of U.S. production, hydrocarbon miscible EOR (mostly natural gas injection) accounts for about 86,000 BOPD or about 1.5 % of U.S. production, and nitrogen miscible/immiscible EOR accounts for about 32,000 BOPD or about 0.5% of U.S. production. These methods account for well over 99% of all U.S. EOR production, with considerably less than 1% coming from chemical EOR, and microbial EOR which is still in the research stage.

CO_2, natural gas, and nitrogen EOR (gas EOR methods) consume much more electric power per barrel of oil produced than thermal EOR methods. Current electric power requirements for gas EOR stands at an estimated 1.5 million hp (1,230 MW), mainly for pumping fluids from the wells (including substantial amounts of produced water), separating product from produced and break through gases, compression for gas injection and reinjection, and pumping product to market and produced water to treatment and reinjection. Thermal EOR methods use only about 300,000 hp (245 MW) at 0.75 hp per BOPD, while CO_2 EOR methods use about 982,000 hp (802 MW) at 5 hp per BOPD.

Objectives

- Provide a comprehensive reference which identifies and characterizes current and potential future U.S. EOR sites and technologies from an electric utility prospective.
- Scope out opportunities for business development for utilities and energy service providers.

Approach

The project team accessed published information, used in-house information/available software/expertise/experience, telephoned contacts at EOR operations, and made some site visits. Having knowledge of both the petroleum industry and the electric and gas industries as they relate to oil and gas production operations allowed the team to identify growth areas using existing technologies, additional growth opportunities in related/emerging technology areas, and generic business opportunities. In addition, detailed information on EOR projects and contact information is provided, which utilities can use on their own or in conjunction with EPRI and the contractor, to look at the most promising opportunities in their service territories in more depth.

Results

This industry segment was characterized in depth, and a number of near-term and longer term opportunities were identified. These are summarized below, and covered in more detail in the abstract and in the body of the report. Also, there will be Pinch (thermal integration) opportunities at natural gas liquids recovery and steam generation operations associated with EOR projects.

(1) Sales efforts to capitalize on staff cuts/softening of biases that used to favor gas drives and (2) directed at firms benefiting from trend to compression outsourcing, (3) Linking electric charges to oil prices, for oil and/or gas share, (4) Donation of low cost pump timers to assist hard pressed customers save electricity/maintenance costs, (5) Assist in projects to speed introduction of pumps which pump fluid mixtures, to save capital/electricity, (6) Focus efforts both on regions of the country where CO_2 EOR is expected to increase (Texas, New Mexico, Kansas, Oklahoma, Utah and Wyoming) and individual successful EOR operations of all other types, which should continue to expand even if production in the aggregate is declining, (7) Focus efforts on small companies in/entering the business (JP Oil, Mitchell Energy and Wiser Oil), (8) Consider supporting coalbed methane enhanced recovery which should grow rapidly using CO_2, N_2 and/or utility flue gas (which could be economic even without carbon tax credits) (potential in many states), and (9) Consider supporting EOR using utility flue gas derived CO_2, which should be economic with a carbon tax.

EPRI Perspective

Chemicals, Petroleum & Natural Gas Target members are interested in new business opportunities for strategic load grow, and load retention. The enhanced oil recovery market segment had not been previously explored in depth. The project resulted in a comprehensive analysis and reference that provides utilities and energy service providers with information to help them focus their efforts on good business opportunities in this energy intensive, large-scale, very low margin business segment.

Keywords

Enhanced oil recovery, EOR
Carbon dioxide, CO_2
Thermal
Nitrogen
Natural gas
Coalbed methane, CBM
Enhanced coalbed methane recovery, ECBM recovery
End use
Industry

ABSTRACT

An abstract of the full content of the report would take more than the two pages allotted; only the key opportunities are summarized below.

1. Field personnel who are hard pressed due to staff cuts are now more inclined to seriously consider electric drives rather than gas due to lower maintenance and reliability problems for electric drives. This is especially the case in emissions restricted regions, particularly the Rocky Mountain Front Range area (Colorado, Wyoming, Utah, Montana, etc.). Electric utility sales personnel should be able to take advantage of this shift in thinking to sell some of their customers on the benefits of electric drives for needed expansions required at existing successful sites for increased produced water pumping and increased injection gas break through and reinjection compression requirements that result as EOR operations age, as well as expansions of projects through placement of additional injection and production wells at the site. Also, the development of low cost adjustable speed drives (such as one being considered in our natural gas program) would greatly aid in this effort.

2. There has also been a trend toward outsourcing compression operations. This could cut into the benefits derived from item 1 above. However, this situation represents a new potential set of customers to sell the benefits of electric drives to, as well as a potential business that some utilities might want to consider getting into.

3. Shell has been successful marketing CO_2 by tying the CO_2 price to oil prices in exchange for part of the oil production. A similar approach could be used by electric utilities to lock in long-term contracts, thus staving off competition as deregulation phases in. Oil is easily sold on commodity exchanges, and an electric utility using this approach could set things up so it never actually had to take oil deliveries (unless they wanted them, or gas instead for their generation operations).

4. As any oil production operation ages, oil production eventually declines and pumps become oversized (running dry part of the time, causing maintenance problems). A simple solution is to put an inexpensive (under $200 per well) timer on the pump which also reduces your customer's electric bill. An investment of this type can pay for itself in about a week. This suggests a program of donating a number of such timers to customers you wish to help (with or without them having to match the number you donate).

5. There are opportunities for larger (possibly Tailored Collaboration) projects to help further introduce multiphase pumps to move multiphase fluid mixtures from production wells to centralized production facilities. These pumps simplify production operations by replacing the separation, gas compression, tank storage, flaring, and liquid pumping required by a conventional system. The capital cost of multiphase pumps is typically about 55% of that for

a conventional system. In addition, the power operating costs are about 45% to 50% of conventional.

6. Based on a very conservative Government oil price track for the next 10 years of $13 to $21/bbl (current price $26/bbl), CO_2 EOR production growth is projected to be flat, other gas EOR to decrease somewhat, and thermal EOR production to decline by 10 to 20%. Even with these poor projections, power demand is expected to grow by about 50,000 hp/yr (40 MW/yr) to satisfy increased pumping and compression requirements for aging projects. Also, with the rebound in oil prices, some floods in the Permian basin (Texas and New Mexico) are expected to continue to expand over the next five years by 10 to 20% (from the basin total of about 145,000 BOPD). New regions with near-term expansion potential including Kansas and Oklahoma, where CO_2 EOR could reach 50,000 BOPD at 250,000 hp (205 MW) within five years, Utah where full development (at least five years away) could also reach 50,000 BOPD, and Wyoming where development will probably wait until 2003, when results of a near by Canadian operation will be available. Also, these are all aggregate projections, and individual highly successful operations will probably expand. For example, in Appendix C, there are thermal projects that are expected to expand. Therefore, electric utilities should study this report to find specific opportunities in their service territories.

7. Also, small independents such as JP Oil, Mitchell Energy, and Wiser Oil are getting involved in EOR. Large companies like Shell are planning to sell off their EOR projects to small companies (with lower over heads), when the projects are no longer economic (with big company over heads). These small companies will need help to keep their EOR operations going for longer periods, and this represents another opportunity for utilities.

8. Some unexpected opportunities are revealed in this report. One is enhanced coalbed methane (ECBM) recovery, which is being developed in a number of commercial-scale pilot tests using either CO_2 or nitrogen. Coalbed methane (CBM) is already an established business accounting for about 6% of total U.S. natural gas production in 1998, and commercial ECBM recovery is expected to grow rapidly. There are suitable CBM basins in the states of Alabama, Arizona, Arkansas, Colorado, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Mississippi, Missouri, Montana, Nebraska, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Utah, Virginia, W. Virginia, Washington, and Wyoming. Therefore, many utilities will have a common interest in helping to speed the introduction of this technology (possible cooperative TC project).

9. Another opportunity is utility flue gas CO_2 sequestration (long-term storage) in EOR, ECBM recovery, and abandoned natural gas fields. For this opportunity to materialize, a carbon tax would have to be enacted in the U.S. (a bill is pending in Congress), carbon tax credit trading would have to be established, and the cost of CO_2 recovery would have to be reduced. Sequestration in ECBM recovery operations may emerge first, since flue gas with just minor processing to remove moisture, oxygen, sulfur and metals may be enough to use the flue gas without separating out the CO_2, and many generation stations are relatively close to appropriate coalbeds. The U.S. DOE has an RFP out for mixed CO_2/nitrogen ECBM recovery studies. The focus of those studies is methane recovery. However, these studies could prove to be the first step towards using flue gas or flue gas/CO_2 blends for ECBM recovery. The contractor that developed this report for EPRI and its membership is going to propose a project for this RFP together with a large oil company.

COMMONLY USED ABBREVIATIONS

EOR	Enhanced oil recovery
CO_2-EOR	Enhanced oil recovery using CO_2 injection
TEOR	Thermal enhanced oil recovery
MW	Megawatt
hp	Horsepower
BO	Barrel of oil
MBO	Thousand barrels of oil
MMBO	Million barrels of oil
BBO	Billion barrels of oil (10^9)
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet (10^9)
Tcf	Trillion cubic feet (10^{12})
$/Mcf	U.S. dollars per thousand cubic feet
$/t	U.S. dollars per metric tonne
$/BO	U.S. dollars per barrel of oil
BOPD	Barrels of oil per day
BWPD	Barrels of water per day
Mcfd	Thousand cubic feet per day
MMcfd	Million cubic feet per day
Bcfd	Billion cubic feet per day
OOIP	Original oil in place
OGIP	Original gas in place
t	Metric tonne
Gt	Gigatonne (billion metric tons)
m^3	Cubic meters
m^3/day	Cubic meters per day

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EXECUTIVE SUMMARY

This EPRI scoping study assesses the current status and future outlook for enhanced oil recovery (EOR) technology in mature oil fields of the United States, highlighting the opportunities for strategic utilities load growth within this important sub-sector of the petroleum industry.

Overall, EOR development is expanding gradually in the U.S., though unevenly by EOR method and by geographic region. The single largest growth area for EOR power demand is expected to be within carbon dioxide floods in the southwestern and west-central U.S. (west Texas, New Mexico, Colorado, Utah, Wyoming), as well as the Gulf Coast region (east Texas, Louisiana, Mississippi). Power demand growth will be primarily for lifting, processing, treatment, compression, and disposal of produced fluids. Thermal EOR, concentrated in south-central California, is another important power market, but development overall is largely stagnant and power is often supplied internally by cogeneration.

Some EOR projects offer more than electric power marketing opportunities: they are also proven sites for disposing (sequestering) carbon dioxide at modest costs or even full-cycle profit. The total sequestration capacity of EOR in depleted U.S. oil fields is estimated to be approximately 98 Gt of CO_2, representing some 36 years of current CO_2 emissions from U.S. power generation facilities. Power plant flue gas is not currently used as injectant in EOR projects, but R&D is focussing on the use of processed flue gas that could be sold to EOR operators for disposal under an emissions-constrained operating environment. The development of a trading system of emissions credits would greatly expand CO_2-EOR development and power demand worldwide.

In 1998, a total of 707,761 barrels/day (BOPD) of EOR was produced in the U.S., accounting for 12% of total national crude oil production. Thermal EOR (TEOR) is still the dominant EOR technology, with about 393,000 BOPD of enhanced oil production. However, TEOR is much less electricity-intensive than other EOR methods, with an estimated total power capacity of 300,000 hp. Many TEOR fields co-generate electricity along with steam injectant, consuming a total of 680 million ft^3/day of natural gas. With a total installed capacity of 2,100 MW, these cogeneration facilities not only satisfy the internal power demands of nearby TEOR fields, but also export significant amounts of power to the grid. Nevertheless, there remain local opportunities for expanding power demand in TEOR projects.

Production from carbon dioxide floods is the most rapidly growing EOR method, and presents a much larger electric power marketing opportunity. Current CO_2-EOR production is 196,411 BOPD, and is expected to increase slowly to about 200,000 BOPD within the next decade (low oil price scenario). Future growth will likely be focussed on the ongoing Permian basin projects of western Texas and eastern New Mexico. Opportunities for power demand growth are substantial and detailed below. Other gas EOR methods, such as hydrocarbon and nitrogen, constitute the third largest EOR method at 118,350 BOPD combined, but (apart from the Alaskan North Slope) are not expected to increase in the near future due to high costs and generally disappointing performance. Gas EOR methods consume much more power than thermal EOR methods, requiring roughly seven times the power intensity of thermal EOR per barrel of oil produced. Current power requirements for gas EOR stand at an estimated 1.5 million hp, mainly for pumping fluids from the wells, and for processing and compressing produced natural gas and carbon dioxide.

The study identified the following high-potential opportunities for increased use of electricity in EOR operations in the United States:

1. **Compression in Emission-Restricted Environments.** Natural gas fired compression is generally perceived by EOR operators to be less expensive than electric power compression. However, emissions restrictions (VOC and NO_x) favor electricity in certain regions, particularly the Rocky Mountain Front Range area (Colorado, Wyoming, Utah, Montana, etc.). Electric compression is also slightly more reliable and requires less maintenance, which is important to typically understaffed EOR field operators, and the trend has been towards increased use of electric drives. In addition, increased use of waste CO_2 from gas processing and fertilizer plants, for emissions reduction purposes, presents a further opportunity for electric compression.

2. **Expansion of CO_2-EOR Floods.** Current installed power capacity at CO_2-EOR fields is an estimated 982,000 hp (802 MW; using a 5 hp/BOPD ratio). By comparison, thermal EOR capacity is considerably smaller at an estimated 300,000 hp (245 MW; using a 0.75 hp/BOPD ratio). With the rebound in oil prices, some CO_2-EOR floods in the Permian basin are expected to expand in the near term by 10-20% from the current 144,848 BOPD. Independent petroleum producers are breaking into CO_2-EOR flood operations, formerly the exclusive domain of Major oil companies. Power demand will increase as water cuts rise, and CO_2 breakthrough and recycling increases. New regions with near-term expansion potential include western Kansas and the Oklahoma panhandle, where power demand for CO_2-EOR operations could grow rapidly by 125,000 to 250,000 hp. Longer-term expansion potential of comparable size exists for CO_2 flooding in southern Utah, Wyoming, and California.

3. **Declining TEOR Production.** Thermal EOR production in California has declined by more than 20% since its peak in 1988, and is expected to continue to decline, albeit more gradually, under most oil price forecasts. Most TEOR projects are self-sufficient in power generation (cogeneration) and even export significant power to the grid. Despite these unpromising overall trends, there still may be local power demand growth opportunities in Cymric, Kern Front, Midway-Sunset and other California oil fields. In addition, some operators currently performing cogeneration stated that they would consider purchasing power from the grid if prices were reduced.

In addition to these well-defined EOR trends, a completely new growth area is expected to emerge within the 10-year time frame of this report: the combination of enhanced petroleum recovery and CO_2 disposal (sequestration) for emissions reduction.

4. **Sequestration of Carbon Dioxide in EOR Projects (A. Increased Strategic Utilities Load Growth).** Significant volumes of CO2 – an estimated 3 million metric tons/year – are currently being sequestered (permanently stored) in depleted oil fields in the western United

States. Sequestration is an inadvertent but beneficial side effect of routine EOR operations. A CO2 emissions reduction credit was recently introduced into the U.S. Senate, and already is in place or close to adoption in several industrialized countries. If enacted and sufficient in size, such a credit could markedly accelerate investment in CO2-EOR and sequestration technology. Increased EOR development and/or use of depleted oil fields as CO2 disposal sites would boost electricity demand at many existing EOR projects, while opening up new electricity markets in the not-yet-flooded oil fields with appropriate reservoir conditions for this technology.

5. **Sequestration of Carbon Dioxide in EOR Projects (B. Disposal of Flue Stack CO2).** Another sequestration-related opportunity for power producers is to dispose of CO2 separated from flue stack emissions directly into depleted oil fields, supplying the injectant for EOR operations. The revenues from EOR may offset much of the costs of CO2 capture, separation, and compression. (Depleted natural gas fields are also potential disposal sites, but represent high-cost settings because they do not benefit from increased gas production.). EOR operators are already capturing and disposing manmade (anthropogenic) CO2 from fertilizer and gas processing plants. Flue gas CO2 is more costly to capture and process but ongoing R&D into capture and plant design technology is expected to reduce costs. The total capacity for CO2 sequestration in U.S. depleted oil and gas fields is estimated to be 98 Gt (1,853 Tcf), equivalent to about 36 years at the current level of power generation emissions in the U.S. Disposal of CO2 in EOR projects is expected to be economically competitive with other sequestration options, such as forestry.

6. **Enhanced Coalbed Methane Projects (Both Increased Power Consumption and Disposal of Flue Stack CO_2).** An analogous, but actually quite separate, process to EOR is the injection of nitrogen and/or CO_2 into deep coal seams for enhanced coalbed methane (ECBM) recovery. Like EOR, this technology has the potential to improve petroleum recovery (natural gas in this case), while simultaneously sequestering carbon dioxide. In addition, if anthropogenic CO_2 (such as flue gas CO_2) is injected into and sequestered within coal seams, the project could qualify for emission reduction credits. At present, ECBM technology is in the field demonstration stage, with two large pilots underway in New Mexico. If successful, ECBM technology could significantly increase power demand for both water lifting and gas compression in the San Juan, Uinta, Raton, Appalachian, and other coal basins during the next decade (Colorado, New Mexico, Utah, Wyoming, Montana, Virginia, West Virginia, Pennsylvania, Alabama and many other states). ECBM also offers an attractive disposal site for power plant flue gas, particularly since many coal-fired power facilities are located within or adjacent to coal fields.

Many of the details supporting these six opportunities are presented in Appendices A, B, and C. Appendix A provides contact information (names and telephone numbers for EOR field engineers), field reserves, production, number and types of wells, horsepower requirements, geographic data (state, county, size), as well as other data for 195 individual EOR projects in the United States. Appendix B provides CO_2 sequestration capacity and costs for 33 individual petroleum provinces in the United States. Appendix C provides in-depth summaries of power demand and growth opportunities for selected U.S. EOR projects.

While this study represents a comprehensive assessment of power opportunities in EOR, further more detailed work could be helpful in assisting utilities to examine specific opportunities. Such future work could include:

- Fully characterize power opportunities at the specific, particularly rapidly expanding, EOR projects already identified.
- Interview field engineers in greater detail to examine how reduced power costs could impact the economics and decision to expand or implement new EOR projects. Examine the feasibility of linking power prices with oil prices, which could lock in long-term power demand even in deregulated environments. Linking power and oil prices also could reduce risk for EOR operators, thereby stimulating development and increasing power demand.
- Examine the comparative full-cycle costs of disposing CO_2 in EOR projects, depleted oil and gas fields, aquifers, and deep coal seams. Compare cost with other sequestration options, such as reforestation.
- Assess the power demands of the rapidly growing coalbed methane production industry which currently accounts for about half of the water produced in the natural gas sector.

1
INTRODUCTION

Overview

During the past 40 years, a variety of enhanced oil recovery (EOR) methods have been developed and applied to mature and mostly depleted oil reservoirs. These methods improve the efficiency of oil recovery compared with primary (pressure depletion) and secondary (waterflooding) oil methods. Each of these EOR methods is highly energy intensive. Electricity — along with its competing alternative, natural gas — is an important power source for operations in all EOR projects. Electric power is widely used for lifting, transporting, processing, compressing, and re-injecting hydrocarbons, water, and injectants in and around the EOR fields.

With the prospect of deregulation and increased competition in the power generation, transmission, and marketing sectors, it is timely to examine the state of the EOR industry in the U.S. What is the outlook for future EOR development? What are the opportunities for power companies to expand their presence in EOR fields? What are some of the new EOR technologies that will change power demand? How can EOR customers, frequently under cost pressure by low oil prices and competition, be better served by changes in tariff structures? And most recently, with emission restrictions under consideration: Can EOR projects help power generators to handle and dispose of CO_2 emissions in a low-cost, safe manner?

This report, funded by the EPRI, was prepared with the goal of assisting electric power marketers to better understand EOR customers and the emerging technical and economic issues that they face.

The report is organized into the following topics, in rough order of importance from an electricity marketing perspective:

Chapter 1: Introduction

Chapter 2: Carbon Dioxide Enhanced Oil Recovery

Chapter 3: Power Consumption in EOR Projects

Chapter 4: Sequestration of Carbon Dioxide in EOR Projects

Chapter 5: Enhanced Coalbed Methane Recovery

Chapter 6: Thermal Enhanced Oil Recovery

In addition, Appendices A, B and C provide detailed project-specific information on EOR projects in the United States, including power consumption and field contact information.

EOR Technologies

EOR production in the United States totaled an estimated 707,761 BOPD during 1998, amounting to about one-sixth of onshore oil production in the Lower-48 States. Of the many methods developed to improve oil recovery, two of these – thermal and gas injection EOR – are by far the most successful and widely employed. Together, these methods account for over 99% of enhanced oil production in the U.S. Other EOR methods, such as chemical or microbial techniques, have research promise but have not been commercialized in the U.S. (10 to 100 BOPD of total production in R&D pilots during 1998) due to high operating costs and relatively poor performance. EOR technologies are grouped into the following categories for this report

- ***Thermal* EOR** methods include cyclic steam and hot water injection, steam and hot water flooding, and (rarely) the in-situ combustion of hydrocarbons. A common principle of thermal EOR is to heat heavy oil, which reduces its viscosity sufficiently to enable it to flow readily and be economically recovered. Steam processes are generally applied to shallow (<3,000 feet deep), heavy oil deposits that – due to their extremely high viscosity – generally cannot be economically produced by primary or secondary recovery methods. Thermal EOR production totaled an estimated 393,000 BOPD in 1998, more than 99% of which was from California.
- **CO_2-EOR** was more recently applied than thermal EOR. Miscible CO_2 flooding has achieved widespread use in the Southwestern, Rocky Mountain, and Mid-Continent regions of the U.S. Including some additional EOR production in Alaska partly related to CO_2 injection, production totaled 196,411 BOPD in 1998. CO_2-EOR is a major electricity consumer, requiring far more than any other EOR method, and is also the fastest growing EOR application.
- ***Other Gas* EOR** methods include hydrocarbon and nitrogen injection. Hydrocarbon miscible EOR projects produced about 85,883 BOPD in 1998 (after removing the 22% of Alaskan North Slope production related to CO_2). However, 72% of this production was located far from the electrical grid, on the Alaskan North Slope or the offshore Gulf Coast Continental Shelf. Finally, nitrogen miscible/immiscible EOR produced about 32,467 BOPD in 1998. The application of hydrocarbon and nitrogen EOR methods is generally not cost-effective in the U.S. and is expected to continue to decline over the next decade. The power requirements for hydrocarbon and nitrogen EOR are similar to those of CO_2-EOR. These two methods are therefore not discussed in detail in this report, although information for on-going projects is provided in Appendix A, Figure A-3.
- ***Chemical/Microbial* EOR** methods involve addition of chemicals or microbial agents to the reservoir. These agents modify fluid properties to make them more favorable for oil recovery. The principal chemical EOR methods include injection of polymers, surfactants, and alkaline chemicals. Although increasing in some countries, chemical EOR never gained widespread use in the U.S., due to the high cost of chemical agents, and has been declining. Microbial EOR is still in the research phase, with only one small R&D project reported and no additional projects are planned.

In addition, a fourth enhanced recovery technology is just recently being demonstrated on coalbed methane reserves, which is a relatively new but rapidly growing unconventional natural gas resource. Coalbed methane production is also a major electricity consumer.

- ***Enhanced Coalbed Methane Recovery*** using nitrogen and/or carbon dioxide injection is an experimental process that is expected to improve the efficiency of natural gas recovery from deep coal seam reservoirs. It also shows potential for sequestering carbon dioxide at relatively low cost. Several Major oil companies are currently testing this process in the field and plan expanded pilots over the next year to demonstrate and refine this technology. One such planned project will examine the injection of mixtures of CO_2 and N_2, possibly demonstrating the feasibility of injecting power plant flue gas with minimal pre-treatment.

2
OVERVIEW OF ENHANCED OIL RECOVERY USING CARBON DIOXIDE

In this chapter, we provide an overview of the use of carbon dioxide in depleted oil fields for the purpose of enhanced oil recovery (EOR). This is followed in Chapter 3 by detailed discussion of electrical power usage in CO_2-EOR fields, as well as opportunities and strategies for increasing the penetration of electric power consumption in this activity. Finally, Chapter 4 discusses the emerging use of CO_2-EOR technology for sequestering carbon dioxide. CO_2 sequestration in depleted oil fields offers significant potential to the electric power industry, both in providing expanded opportunity for electricity marketing and in offering a low-cost alternative for reducing emissions of greenhouse gases.

CO_2-Flood Enhanced Oil Recovery Processes

In most oil and gas fields, only a small proportion (typically 20-40%) of original oil in place (OOIP) is recovered using standard petroleum extraction methods. Carbon dioxide injected into a depleted oil reservoir with suitable characteristics can achieve enhanced oil recovery through two processes, miscible or immiscible displacement. Miscible processes are more efficient and most common in active EOR projects. However, immiscible flooding may become increasingly important if widespread CO_2 sequestration takes place in depleted oil fields, where reservoir conditions are not suitable for miscible flooding.

Carbon dioxide can exist in four distinct phases depending upon temperature and pressure: vapor or gas, liquid, solid, and supercritical. Oil and gas operators generally handle CO_2 in its supercritical phase, which is stable above the critical point of 6.9 MPa (1087 psi) and 31°C (88°F). In its supercritical state, CO_2 may be considered to be a fluid, wherein the terms gas and liquid lose their conventional meaning. In general terms, the supercritical phase behaves like a liquid with respect to density, and like a gas with respect to viscosity.

Miscible CO_2 Displacement: Under suitable reservoir pressure and oil density conditions (generally deeper than 1,200 m with oil lighter than 22° API gravity), injected carbon dioxide will mix thoroughly with the oil within the reservoir such that the interfacial tension between these two substances effectively disappears. Theoretically, all contacted oil can be recovered under miscible conditions, although in practice recovery is usually limited to about 10 to 15% of OOIP.

Immiscible CO_2 Displacement: When reservoir pressure is too low and/or oil gravity too dense, the injected carbon dioxide remains physically distinct from the oil within the reservoir. However, injected CO_2 still can improve oil recovery by causing the oil to swell, reducing the oil's density and improving mobility. Currently, only one large EOR project (in Turkey) utilizes immiscible processes. Several other smaller immiscible EOR projects are underway in the U.S. Although less efficient, the use of immiscible displacement processes may expand if CO_2 sequestration is implemented on a large scale in depleted oil fields.

Once oil is mobilized by CO_2, or freed from its residual saturation state that normally locks it in place within the reservoir, it must be either pushed or pulled to the production well. For improved oil recovery, CO_2 injection frequently is alternated with water injection in a water-alternating-gas (WAG) process. In practice, a "slug" of injected CO_2 is repeatedly alternated with water drive, over intervals ranging from several weeks to months (Figure 2-1).

Figure 2-2 illustrates the typical surface configuration of an enhanced oil recovery project, while Figure 2-3 shows the linkages of the field to CO_2 supplies and petroleum markets. Significant electric power may be used in each of these steps:

- Carbon dioxide from natural or anthropogenic sources (potentially including flue gas) is transported to the field via a dedicated pipeline and injected via a dedicated CO_2 injection well (*major* electric power demand for anthropogenic sources only).
- Oil, water, natural gas, and carbon dioxide are produced by a production well and then these fluid components are separated at the surface (*major* electric power demand).
- Oil and natural gas is collected and sold. Waste water is processed and then re-injected in a water disposal well (*major* electric power demand).
- Carbon dioxide is separated, compressed, and recycled back into the formation in the CO_2 injector well (*major* electric power demand).
- The life span of a typical CO_2-EOR project is in the range of 10 to 30 years, depending on a variety of technical and economic variables, such as the ratio of CO_2 injection to oil recovery, market prices of oil and the CO_2 injectant, operational costs, and other factors.

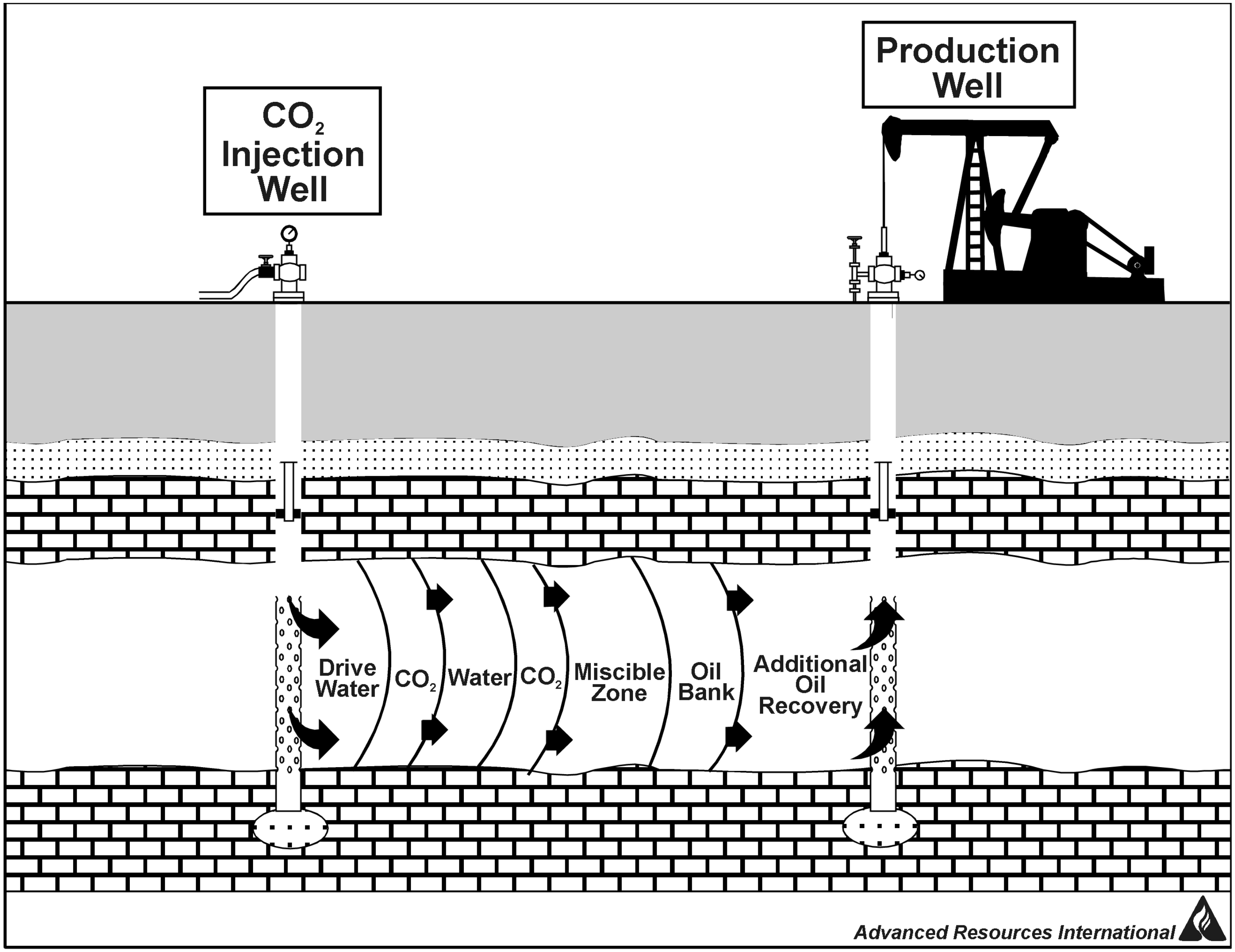

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Figure 2-1
Carbon Dioxide Flooding

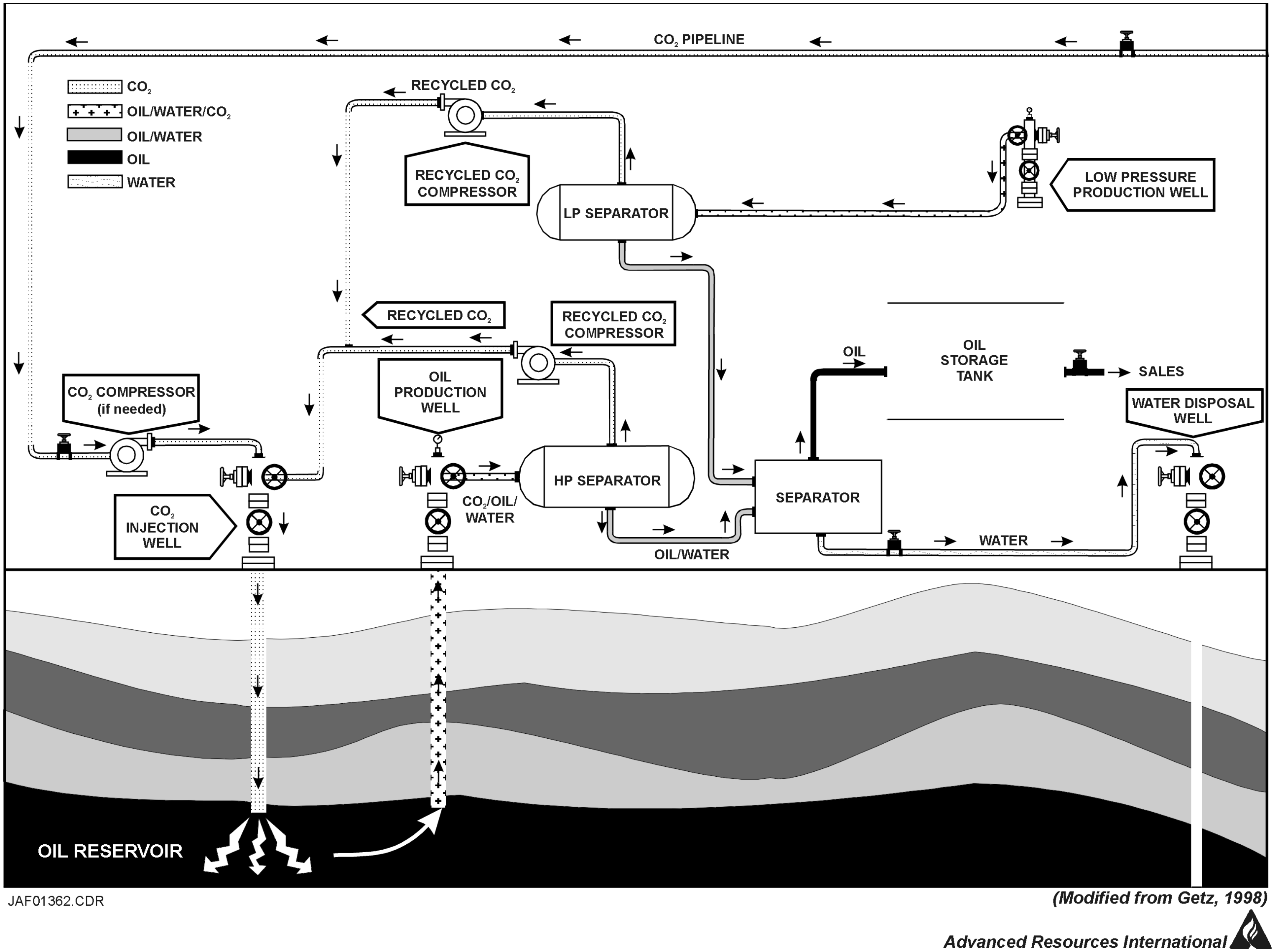

Figure 2-2
Typical CO_2 EOR Field Operation

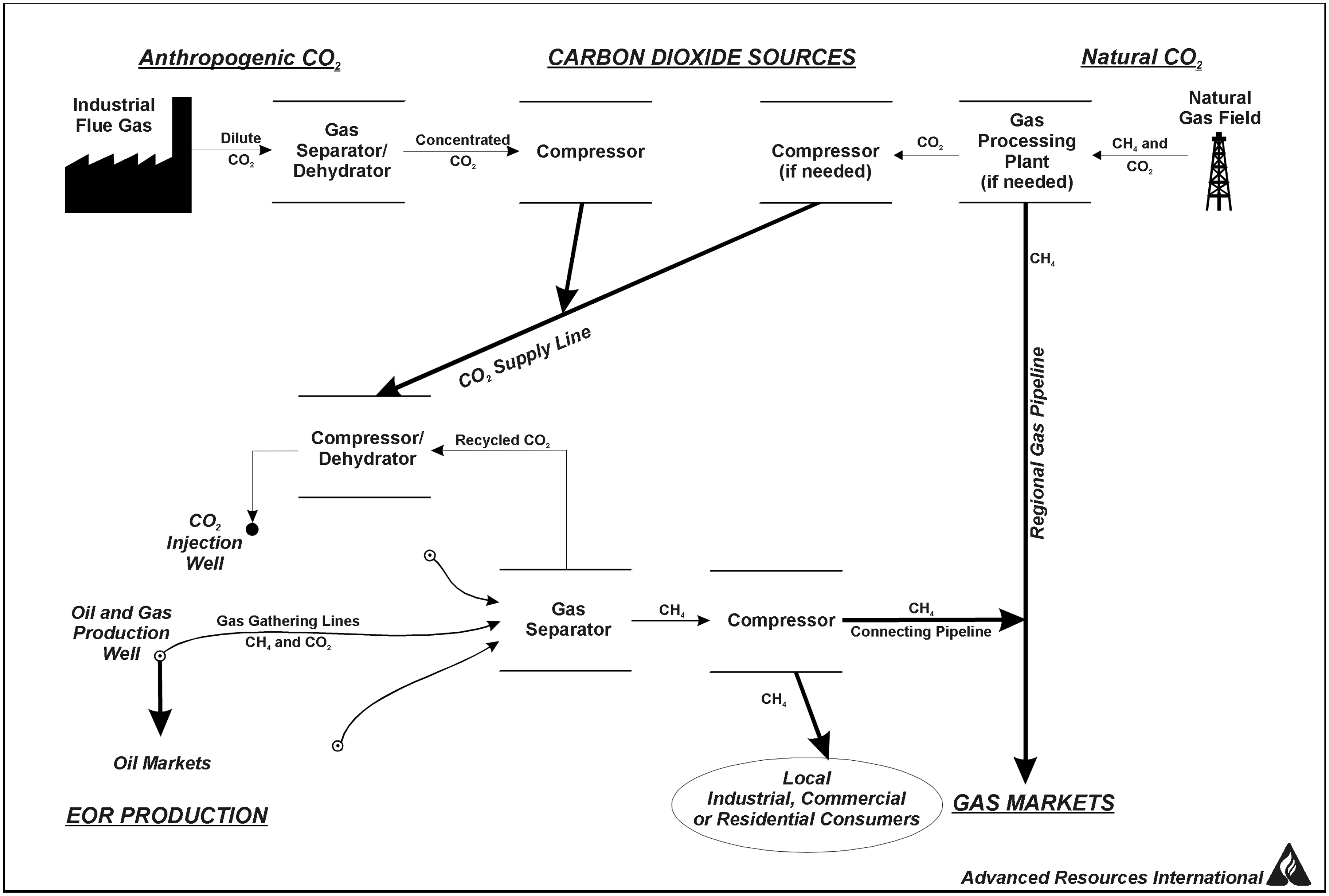

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Figure 2-3
Components of a CO_2-EOR Recovery System

Worldwide CO_2-EOR Activity

This section presents information on current and past CO_2-flooding activity for enhanced oil recovery in mature oil and gas fields. The purpose of this discussion is to provide first an overview of the operational history and performance of commercial CO_2-EOR operations. Next, three individual field case histories of CO_2-EOR operations are presented. The case histories provide more specific information and insight into the variety of geological reservoir settings, CO_2 sources (natural or anthropogenic), types of operating companies and their strategies, production technologies employed, and other key variables that are relevant to electricity usage in EOR projects.

Worldwide CO_2-EOR production during 1998 averaged approximately 33,546 m^3/day (210,661 BOPD) from 79 individual projects, accounting for only a tiny fraction (0.3%) of total worldwide crude oil production of 10.7 million m^3/day (67.1 million BOPD) during this period. The United States accounts for the vast bulk (93%) of worldwide CO_2-EOR operations. Currently, only one other country besides the U.S. (Turkey) has significant CO_2-EOR production. Two other countries (Trinidad, and Canada) have small, essentially research-level EOR production (Table 2-1).

From the beginning of CO_2 flooding application in the early 1970's, the U.S. has been the focus of CO_2-EOR technology development and investment. Total U.S. production during 1998 was estimated at 31,276 m^3/day (196,194 BOPD) of incremental enhanced oil recovery from 74 individual field CO_2 projects. Turkey was second at 2,146 m^3/day (13,500 BOPD), essentially all from one large field. Trinidad and Canada had much lower production levels, 80 and 40 m^3/day (500 and 250 BOPD), respectively, from several small pilot fields. (A large CO_2 flood planned at Weyburn field in Saskatchewan is expected to boost Canada's production significantly during the next few years, but had not yet been implemented at report time.)

Table 2-1
CO_2-EOR Production by Country (1998)

		CO_2-EOR Production	
Country	**Number of CO_2-EOR Projects**	**Barrels per Day (BOPD)**	**Cubic Meters per Day (m^3/day)**
United States	74	196,411	31,276
Turkey	1	13,500	2,150
Trinidad	2	500	80
Canada	2	250	40
TOTAL	**79**	**210,661**	**33,546**

Generally, data concerning the specific volumes and rates of CO_2 injected into depleted oil fields for EOR are not publicly available. This section primarily reports information on enhanced oil recovery, which operators **are** required to report to state-level regulatory agencies in the United States. Most of the CO_2 injection data used in this study was gathered from case studies reported in the technical literature or directly from EOR field engineers. Later in Chapter 4, we specifically discuss the use of electricity in these fields and opportunities for growth in power consumption.

United States CO_2-EOR Development

Current Status. The United States, where the technology for CO_2 enhanced oil recovery was first demonstrated on a large scale, remains by far the world's most active area for CO_2-EOR development and production. During 1998, enhanced oil recovery from 74 individual CO_2 floods in the U.S. averaged approximately 31,190 m^3/day (196,194 BOPD) (Figure 2-4).

Most (53) of these CO_2 floods are located in the southwestern U.S., within the mature Permian basin of western Texas and eastern New Mexico. Many depleted oil fields with reservoir properties suitable for CO_2 miscibility exist in this region (Map 2-1). The Permian basin has been, and is expected to continue to be, the worldwide center of CO_2-EOR technology development and application. Most of the EOR projects here are large and long-term. This study focuses primarily on power opportunities in the Permian basin (Map 2-2).

Other CO_2 floods in the United States are located in the Rocky Mountain region (6 projects), the Mid-Continent region of Oklahoma and adjoining states (8 projects), and coastal onshore Gulf of Mexico (5 projects). In addition, two large-scale hydrocarbon-miscible EOR floods located on the North Slope of Alaska utilize CO_2-rich (an estimated 22%) hydrocarbon gas, which is re-injected to maintain reservoir pressure and maximize crude oil production. Altogether, CO_2 enhanced oil recovery projects accounted for approximately 3.1% of the total crude oil produced in the United States during 1998.

Most CO_2-EOR projects utilize naturally occurring carbon dioxide, which is produced from high-pressure, high-purity underground deposits. The largest of these natural CO_2 deposits is Shell's McElmo Dome field in southwestern Colorado, which contains over 283 million m^3 (10 Tcf) of proved CO_2 reserves at a pressure of about 2,000 psi. Other large CO_2 sources that supply injectant to the Permian basin include Mobil's 2-Tcf Bravo Dome and Arco/Exxon's Sheep Mountain field in southeastern Colorado.

However, a small but significant fraction of EOR projects utilize anthropogenic (man-made) CO_2 sources, such as waste streams from fertilizer or gas processing plants (Table 2-2). These anthropogenic CO_2 sources are noteworthy in that, along with power plant flue gas, they would qualify for emissions reductions credits under the bill currently in debate in the U.S. Senate.

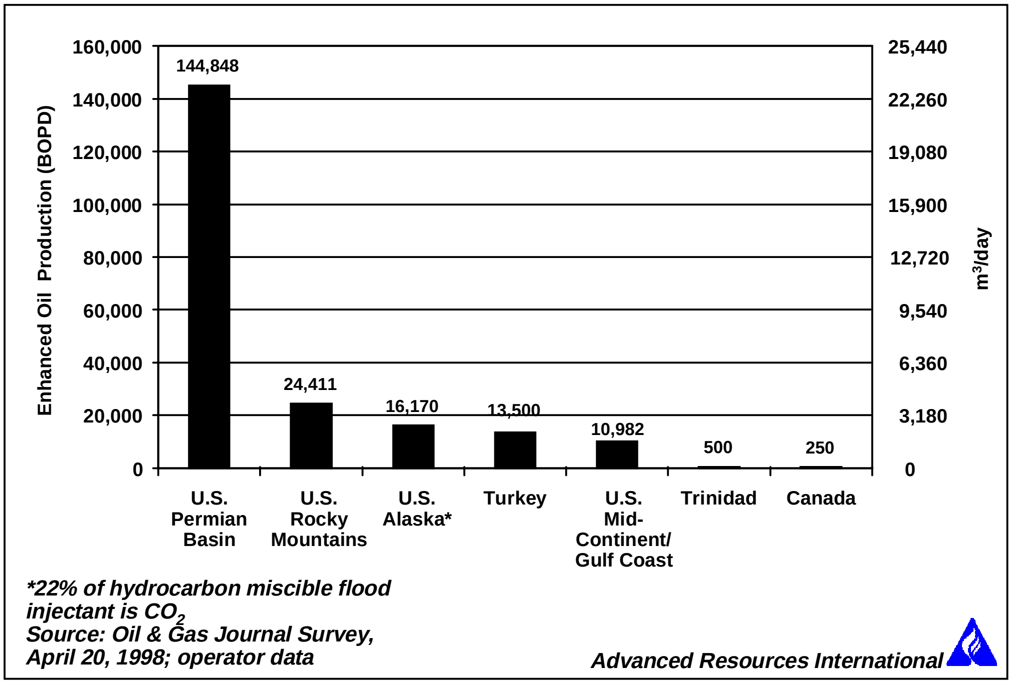
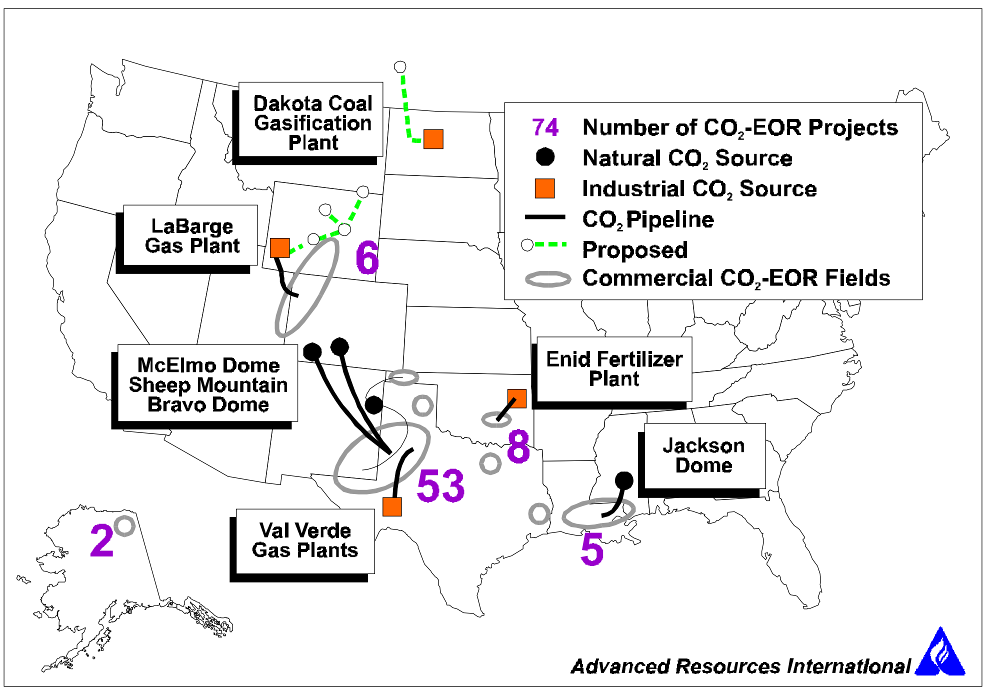


Figure 2-4
Enhanced Oil Recovery Using CO_2 Flooding (1998)



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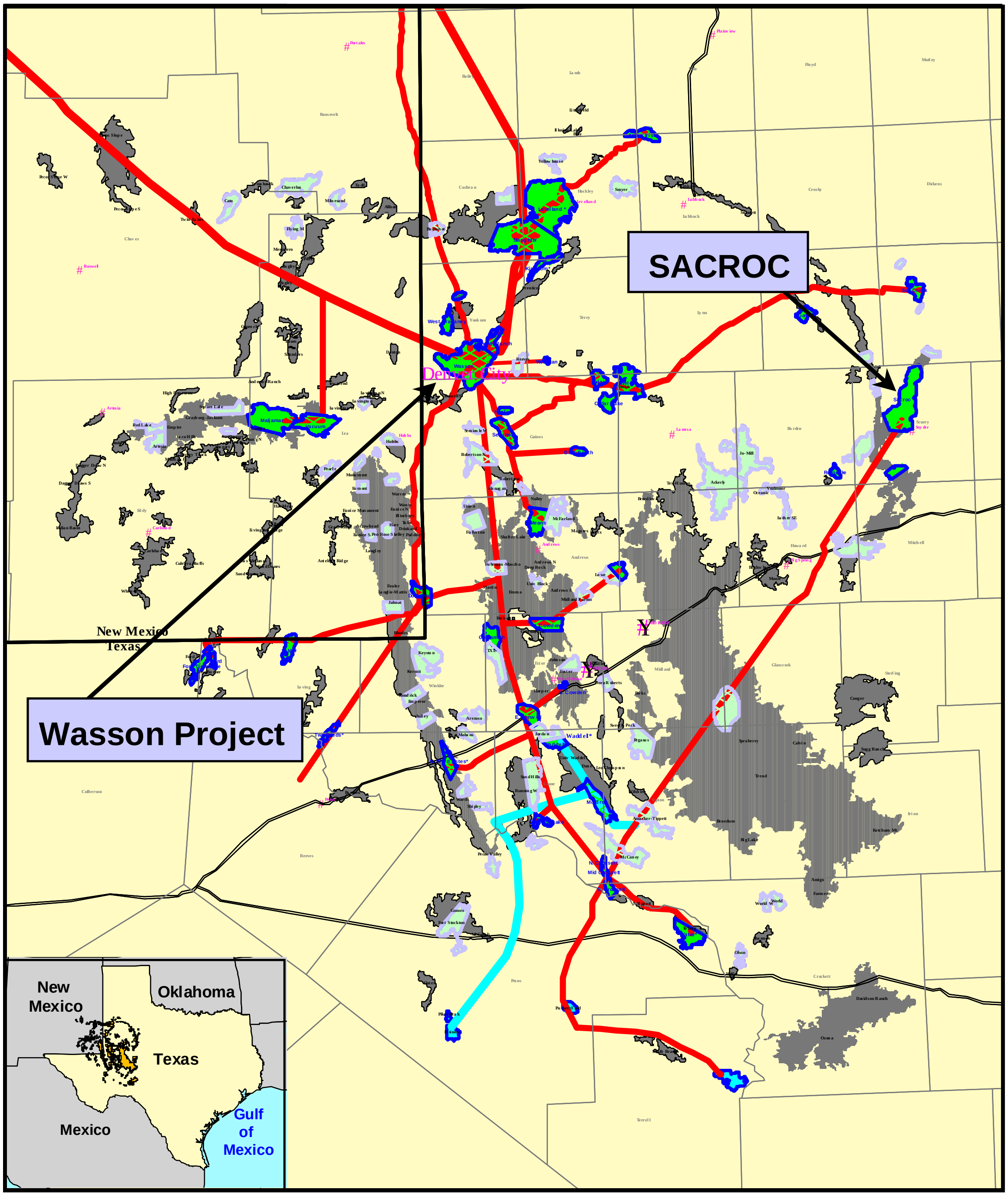
Map 2-1
Location of Commercial CO_2-EOR Projects in the United States



September 23, 1999

Advanced Resources International

Map 2-2
CO_2 Enhanced Oil Recovery Projects, CO_2 Pipelines, and Depleted Oil and Gas Projects of the Permian Basin, Texas and New Mexico, U.S.A.

Table 2-2
Active U.S. CO_2-EOR Projects That Utilize Anthropogenic Waste CO_2

State	Plant Name(s)	Plant Type	Peak CO_2 Supply (MMcfd) (10^6 m^3/d)		EOR Fields	Field Operator
Texas	Mitchell, Gray Ranch, Puckett, Terrell	Gas Processing	250	7.08	SACROC Crossett	Pennzoil, Altura
Colorado	LaBarge	Gas Processing	150	4.25	Rangely	Chevron
Oklahoma	Enid	Fertilizer	35	0.99	Purdy	Occidental
Louisiana	Koch	Gas Processing	25	0.71	Paradis	Texaco
	Total		**460**	**13.03**		

CO_2-EOR production is concentrated within a small number of large-scale, highly productive projects that account for most EOR production in the United States (along with essentially all of Turkey's EOR production) (Table 2-3). Just five large projects account for about half of total worldwide CO_2-EOR production. This concentration underscores the importance of focusing electricity marketing efforts on large current projects, particularly those with significant expansion potential to adjacent depleted oil zones.

Table 2-3
The Five Largest Active CO_2-EOR Projects Account for Half of Worldwide Production (1998)

Operator	Field	Basin	Area (km^2)	Wells		EOR Production	
				Production	Injection	BOPD	m^3/d
Altura	Wasson (Denver)	Permian	177	735	365	30,700	4,900
Amerada Hess	Seminole (Main)	Permian	64	408	160	30,000	4,800
Chevron	Rangely (Weber)	Rockies	61	204	200	13,881	2,200
Turkish Petrol.	Bati Raman	SE Turkey	44	145	41	13,500	2,150
Mobil	Salt Creek	Permian	49	85	48	12,000	1,900
Total 5 Largest Projects						**100,081**	**15,950**

Historical Development. Commercial injection of carbon dioxide for enhanced oil recovery began at SACROC field in the Permian basin in 1972 (see detailed case study later in Chapter 2). CO_2 flooding was later implemented at depleted oil fields in the Rocky Mountain, Mid-Continent and Gulf Coast regions, involving new types of reservoir formations (predominately sandstone rather than the carbonate reservoirs prevalent in the Permian basin). CO_2-EOR projects also were implemented on a smaller scale in Turkey, Canada, Hungary, and Trinidad during the 1970's and 1980's.

CO_2-EOR production grew modestly in the U.S. throughout the 1970's and early 1980's, sparked by rising oil prices and promising pilot field demonstrations. During the late 1980's and 1990's production accelerated markedly, even in the face of low to moderate oil prices and sharp overall reductions in upstream E&P capital spending by oil companies.

Development of CO_2-EOR was able to increase despite low oil prices for three primary reasons. First, EOR development and operating costs fell, as technological advances continued to make field operation and monitoring more efficient. Second, CO_2 supplies increased with the construction of new long-distance pipelines from natural CO_2 deposits in Colorado. Third, oil companies (particularly the Majors) become organizationally leaner and more efficient operators and could still make money from most EOR projects despite lower oil prices. Limited fiscal incentives for enhanced oil recovery projects in the United States also had a favorable, albeit much more modest, impact on investment. CO_2-EOR production in the U.S. increased eight-fold from less than 4,000 m^3/day (25,000 BOPD) in 1985 to 31,000 m^3/day (196,000 BOPD) by 1998 (Figure 2-5).

Coincident with the growth in EOR, CO_2 deliveries to the Permian basin have grown markedly during this period (Figure 2-6). Most (>90%) injectant is supplied from three natural CO_2 deposits in Colorado: McElmo Dome, Sheep Mountain, and Bravo Dome. In addition, a small fraction of the Permian basin CO_2 supply has historically come from anthropogenic sources: waste CO_2 streams from four natural gas processing facilities in the Val Verde sub-basin, located in the southern Permian basin. In contrast, most of the CO_2 supply in the Rocky Mountain and Midcontinent regions, the other main EOR areas in the United States, comes from anthropogenic sources such as natural gas processing plants and fertilizer production facilities.

Projected Future Development. Enhanced oil recovery from CO_2 flooding is expected to continue to increase in future years under most world oil price scenarios. As part of the U.S. Department of Energy's Oil and Gas Supply Model, which forecasts future oil and gas production in the United States, Advanced Resources developed an enhanced oil recovery submodule that specifically assesses the economics of CO_2-EOR projects in the United States. The field-based economic model evaluates the production costs of existing CO_2-EOR projects in the U.S., as well as the development costs for expanding CO_2 flooding into new depleted oil fields, providing the ability to systematically forecast future EOR production (Stevens and Kuuskraa, 1997). Alaskan CO_2-EOR production, which is not simulated in this model, was assumed to remain constant at the current level of about 2,400 m^3/day (15,000 BOPD).

Future EOR production and electricity consumption will depend primarily on oil prices and technological improvements. Higher oil prices enhance revenues and profitability, leading to increased investment in EOR facilities and eventually higher levels of production (as well as associated electricity consumption). Technological improvements – such as improved flood monitoring using 4-D seismic surveillance – lower extraction costs, which also enhances profitability, stimulating investment and increased production. To estimate future EOR production in the United States, we conducted a model run using USDOE's "Reference" (most likely) Oil Price track, and also assumed a "Reference" pace of technological advancement (USDOE, 1998). (This price track envisions the average price of oil in the continental U.S. increasing from U.S. $13/bbl to $21/bbl over this period, in constant 1997$.)

Our forecasted scenario is based on current EOR market conditions, under which operators receive no financial benefit for sequestering CO_2. Currently, operators must cover the costs of purchased CO_2, as well as all other capital and operating costs, solely on the basis of sales of oil production. Should a market of tradable CO_2 emissions credits develop in the future, lower net operating costs would accelerate and intensify the development of EOR resources in the United States and worldwide.

Under the reference price/technology scenario, we forecast that CO_2-EOR production in the United States will remain relatively flat until 2010, after which higher oil prices stimulate increased investment and production. Production is forecasted to increase to a peak about 35,000 m^3/day (220,000 BOPD) in 2015, before declining as the currently identified resource base becomes substantially depleted (Figure 2-5).

However, higher oil prices, improved technology (i.e., at a faster pace than assumed under Reference technology), or emissions reduction credits all could lead to significantly higher EOR production and electricity usage.

Future CO_2-EOR Projects. In addition to the ongoing Permian basin and Rocky Mountain CO_2-EOR floods, several new areas have potential for application of this enhanced oil recovery technology:

- **Kansas-Oklahoma:** The success of Mobil's Postle CO_2 flood in Oklahoma, which began in November 1995 and currently produces 7,000 BOPD, has raised interest in expanding CO_2 flooding to other depleted oil fields in western Kansas and the Oklahoma Panhandle. The Lansing-Kansas City oil fields are attractive because they have high waterflood efficiencies, good oil characteristics, and relatively high residual oil saturation. CO_2 flooding in western and central Kansas could recover 100 to 400 million barrels of incremental oil (Oil & Gas Journal, 1998).

  Starting in year 2000, Shell CO_2 Company, MV Partners, and Kansas University plan a multi-year project on 220 acres to demonstrate the effectiveness of CO_2 flooding in the Morrow formation. If this project succeeds, Shell's CO_2 pipeline from Bravo Dome in northeastern New Mexico to Postle field in Oklahoma will be extended to southwestern Kansas to supply injectant for this region. CO_2 flooding could realistically add 50 to 75 million barrels of oil reserves. The minimum oil prices required for EOR to be economic in this region are estimated at $16 to $18/barrel, higher than the Permian basin, which has better infrastructure and lower costs. CO_2-EOR production could reach 25,000 to 50,000 BOPD in Kansas-Oklahoma, with an associated energy demand of 125,000 to 250,000 HP. Most of the potential Kansas EOR operators are independent producers.

- **Utah:** The Paradox basin in southeastern Utah was the focus of a recent DOE-funded study, which indicated the potential for up to 150 million barrels of EOR reserves using CO_2 flooding. This area is within 100 miles of Shell's large McElmo CO_2 field, which could readily supply injectant for EOR. Full development could reach 50,000 BOPD with an associated energy demand of 250,000 HP, but the development appears to be at least 5 years away. Texaco is considering a small CO_2-EOR pilot in the Aneth field that may include a novel multiphase-flow gathering system (Pagano and Christianson, 1999).
- **Wyoming:** PanCanadian Petroleum's large CO_2 project at Weyburn field in Saskatchewan, just now getting under way, has raised interest in the EOR potential of Wyoming's Powder River and Big Horn basins. CO_2 could be transported from the southwestern part of Wyoming. Development would probably await initial results from the Weyburn field, which should become clear by about 2003.

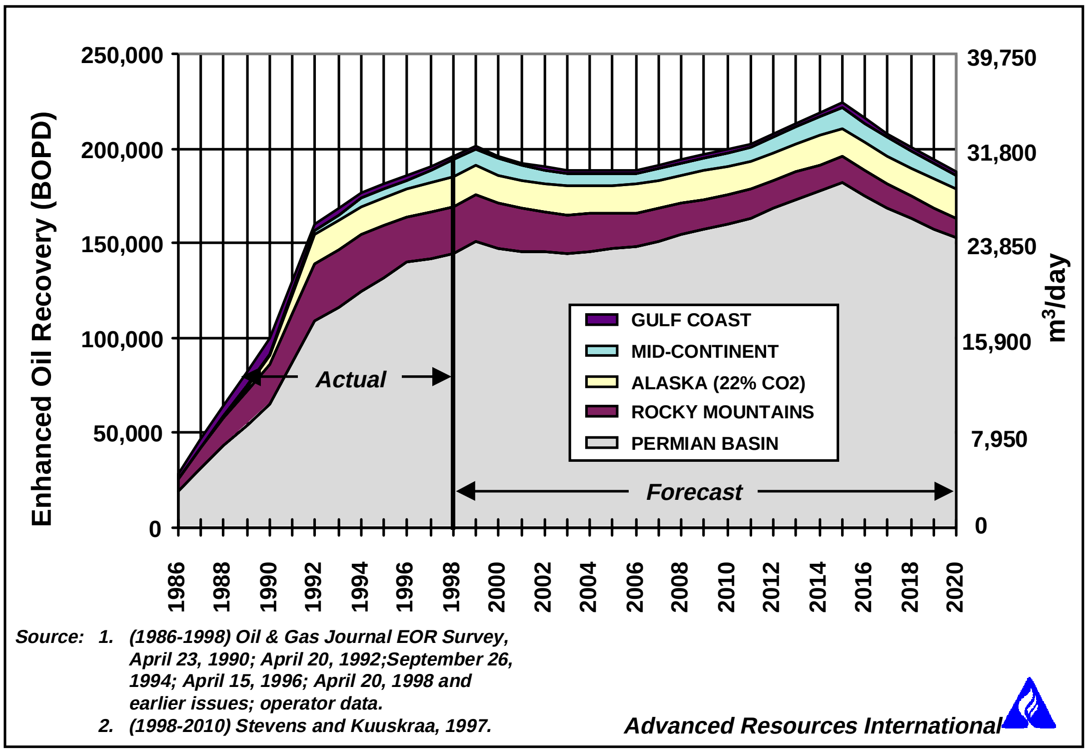


Figure 2-5
CO_2-EOR Production History (1986-1998) and Production Forecast (1998-2020) in the United States Using 1999 USDOE-EIA Annual Energy Outlook Reference Oil Price Track

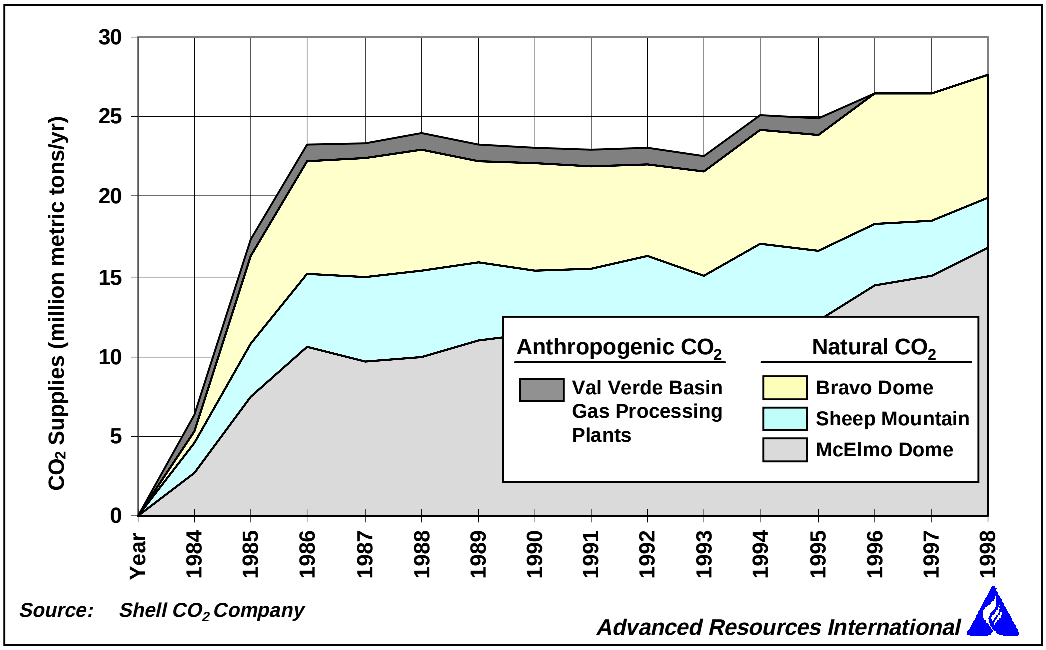


Figure 2-6
CO_2 Deliveries to EOR Projects in the Permian Basin

CO_2-EOR Production Companies

Majors. Most of the firms involved with CO_2-EOR operations are "integrated" major oil companies, i.e., active in refining and marketing activities as well as production operations. Smaller independent (i.e., non-integrated) producers, which actually account for most oil production in the U.S., are generally less active in CO_2-EOR activities. Large oil companies tend to have the necessary expertise in engineering design and implementation of complex EOR projects.

Although large EOR projects can add significant oil reserves, they often require more than 5 years to pay out, due to high initial investment and operating costs and resulting low profit margins. Smaller independent oil companies prefer payback periods of 3 years or less. In addition, EOR projects can be particularly vulnerable to periods of low oil prices. Large companies tend to have the relatively long-term investment viewpoint required for CO_2 floods to be economic.

A ranking of oil companies by CO_2-EOR production is provided in Table 2-4. **(**These data are reported by operator; actual ownership of produced oil may differ.) The largest producers include Altura (an alliance of Shell and Amoco that is limited to the Permian basin), Amerada Hess (which operates the large Seminole Unit in the Permian basin), followed by Mobil, Arco (mainly through their Alaskan North Slope hydrocarbon-miscible projects), Chevron, Texaco, Exxon, Pennzoil (recently acquired by Devon Energy), and Amoco (non-Altura production). All of these companies are large, integrated "Majors."

Table 2-4
Production of CO_2-EOR by Company (1998)

Rank	Percent of Total	Company	Number of Projects	CO_2-EOR Production	
				BOPD	m^3/day
1	27%	Altura (Shell/Amoco)	13	55,928	8,892
2	14%	Amerada Hess	3	30,500	4,849
3	11%	Mobil	7	22,800	3,625
4	10%	ARCO (incl Alaska)	3	21,070	3,350
5	7%	Chevron	3	14,511	2,307
6	6%	Turkish Petroleum Co.	1	13,500	2,146
7	5%	Texaco	5	10,270	1,633
8	4%	Exxon	4	9,250	1,471
9	4%	Pennzoil	1	9,000	1,431
10	3%	Amoco	4	7,030	1,118
	8%	Other U.S./Worldwide	35	16,585	2,637
	100%	**TOTAL**	**79**	**210,444**	**33,459**

Source: Oil & Gas Journal, 1998; operator data.

Independents. Although smaller independent oil companies remain minor players in CO_2-EOR, in recent years they have become increasingly active, particularly in CO_2 flooding of relatively small properties. Some of the leading smaller companies currently involved in CO_2-EOR include JP Oil, Mitchell Energy, and Wiser Oil. This trend has in part been aided by technology transfer and, on occasion, financial assistance provided by the U.S. Department of Energy.

Altura, the largest EOR operator in the Permian basin, is reportedly preparing for a major divestiture of EOR properties set for later this year. This move may be in part because of the recent merger of Amoco with BP. It is likely that independent oil companies will continue to expand their presence in the Permian basin through this property sale.

Shell CO_2 Co., the largest supplier of injectant in the Permian basin, has recently targeted independent producers in the Permian basin and other areas to increase the market demand for CO_2. For example, Shell conducts short courses and seminars in CO_2-EOR technology aimed at the engineering staff and management of independent oil producers. Shell CO_2 Co.'s technical staff also helps to screen reservoir candidates, using reservoir and economic models they have developed, and to design appropriate flooding programs for independent producers.

On occasion, Shell has shared some of the risk that operators undertake in implementing a CO_2 flood – typically lower future oil prices or the technical risk of lower-than-expected oil production – by contracting to supply CO_2 to the project at a reduced cost in return for an equity share in the enhanced oil production stream. In addition, supply contracts signed between Shell and EOR operators often link CO_2 supply costs to oil prices, which again reduces operator risk (albeit at the cost of reducing upside potential). Shell's entrepreneurial approach has helped to expand CO_2 flooding in the United States during the 1990's, even during a period of low-to-moderate oil prices.

Shell's approach for linking CO_2 supplies to oil prices could serve as a model for entrepreneurial electricity marketers. Power supply unit costs could be similarly linked to oil prices. This would assist oil producers during periods of low oil prices, while maintaining electricity demand.

USDOE. The U.S. Department of Energy (USDOE) also has taken an active role in promoting industrial R&D into advanced CO_2-EOR production technologies and innovative applications within new reservoir types and settings. USDOE has co-funded R&D in a number of EOR fields and potential reservoir candidates throughout the United States.

For example, the USDOE provided cost share to Chevron and Advanced Resources International, Inc. to evaluate and implement a pilot demonstration of CO_2 flooding into the siliceous shale reservoirs of the Monterey Shale within California's San Joaquin Valley. The Monterey Shale is a reservoir and rock type that has never been proven to be amenable to CO_2 flooding (Chevron, 1998). If successful, this technology could be expanded to an entirely new reservoir type with approximately 16 billion m^3 (100 billion barrels) of EOR potential and open up an entirely new market for electricity demand. An additional, although initially unintended, benefit of this R&D could be providing a low-cost (or even profitable) underground disposal site for anthropogenic CO_2 emissions in California.

Case Studies of CO_2-EOR Projects

Introduction. This section presents detailed case histories of three producing CO_2-EOR fields, located in two different regions of the United States. The focus is on the larger and longer-lived projects, representing some geologic and geographic variety, to provide background on the actual performance and technology application in commercial fields.

No truly comprehensive case studies of CO_2-EOR floods have been published in the technical literature. Thus, for this study we had to piece together information and analysis based on numerous published accounts, which are usually limited to the specific performance of individual production technologies or strategies. We augmented this public information with discussions held with EOR field operating companies. The case histories are:

- **(U.S.A.) Pennzoil's SACROC Unit**, the world's first large-scale CO_2 flood, located within the Permian basin of West Texas. SACROC produces from a depleted carbonate reservoir and has the longest history of CO_2 injection and EOR production. Most of the CO_2 injected into this field came from gas processing plants (anthropogenic), although the field has recently switched to natural CO_2 sources.
- **(U.S.A.) Shell's Wasson-Denver Unit**, also located within the Permian basin of West Texas, is currently the world's largest CO_2 flood in terms of enhanced oil production and CO_2 sequestered. This project involves injection of CO_2 from natural sources into a depleted carbonate oil reservoir.
- **(U.S.A.) Chevron's Rangely Weber Unit**, located in northwestern Colorado, is the world's third largest CO_2 flood. The anthropogenic CO_2 injectant used exclusively for this project comes from a gas processing plant. The geologic setting and reservoir type (sandstone) are characteristic of Rocky Mountain Foreland basins, distinctly different from the carbonate reservoirs of the Permian basin.

SACROC Unit (Pennzoil E & P Co.)

(Hawkins et al., 1996; Wingate, 1995; Brock and Bryan, 1989; operator discussions)

Background. Initiated in 1972, Pennzoil's SACROC Unit in the Permian basin was the world's first large-scale commercial carbon dioxide EOR flood. The SACROC (Scurry Area Canyon Reef Operators Committee) operation covers a 205-km^2 (50,000-acre) area within the depleted Kelly-Snyder oil field in the eastern part of the Permian basin, west Texas (Map 2-2; Table 2-5).

Light oil is produced mainly from limestone reservoirs of the Canyon Reef Formation of Late Pennsylvanian age. The field is internally complex. Tight shale zones vertically segregate the oil reservoir into numerous stacked compartments that are not in pressure communication; fluid flow is essentially horizontal. The SACROC Unit is the largest field within the Horseshoe Atoll geologic trend, an arcuate-shaped structure that holds enormous in-place oil resources and sequestration potential.

Primary oil production for the SACROC Unit began shortly after discovery in 1948. Secondary (waterflood) operations were initiated in 1954 to maintain oil production. CO_2 miscible flooding was implemented in 1972 and has proceeded continuously for 26 years.

During the period 1972 to 1995, CO_2 injectant for the SACROC project was supplied from nearby natural gas processing plants. These four natural gas plants (Terrell, Grey Ranch, Mitchell, and Puckett) in the southern Permian basin separate naturally occurring CO_2 from natural gas production to enable the latter to meet methane pipeline corrosion specifications. Because the separated CO_2 byproduct otherwise would be emitted to the atmosphere, the CO_2 injectant used during this period may be considered as anthropogenic-sourced. High-pressure, pure CO_2 was transported to the SACROC field by a devoted 41-cm (16-inch) diameter, 270-km (170-mi) long pipeline operated by Canyon Reef Carriers (CRC). Although pipeline capacity was about 6.8 million m^3/day (240 MMcfd), actual transported CO_2 volumes averaged only 1.4 million m^3/day (50 MMcfd).

Table 2-5
Key Parameters of Pennzoil SACROC CO_2-EOR Project, Permian Basin, U.S.A.

Parameter	Metric Units	English Units
Depth	2,040 m	6,700 feet
Oil Gravity	0.82 g/cc	41° API
Current EOR Area	200 km^2	49,900 acres
Number of Wells	325 Producers, 57 CO_2 Injectors	
Original Oil in Place (OOIP)	336 million m^3	2.113 billion barrels
Current EOR Production	1,430 m^3/day	9,000 BOPD
Current Cumulative EOR Production	11.1 million m^3	69.4 million barrels
Estimated Ultimate EOR (%OOIP)	27 million m^3 (8.0%)	169 million barrels (8.0%)
Current Gross CO_2 Injection Rate	1.7 million m^3/day	60 MMscfd
Cumulative Gross CO_2 Injection (1996)	30 x 10^9 m^3 (0.06 Gt)	1.04 Tcf
CO_2 Source	Gas Processing Plant (1972-1995); Natural Source (1996-on)	

Note: 1 metric tonne CO_2 at U.S. standard conditions (1 atm and 60° F) = 534.76 m^3

The source of CO_2 supply to SACROC changed in 1996. Delhi Pipeline Co. purchased the CRC pipeline and converted it to natural gas transportation service. Simultaneously, SACROC and the nearby North and South Cross fields converted to natural carbon dioxide injection supplied by Shell CO_2 Co. The gas processing plants in the Val Verde basin became isolated from market and the waste CO_2 was vented during 1996-1998. However, in September 1998 Petro Source Corp., MCNIC Pipeline & Processing Co., and ARCO Permian completed a new 25-cm (10-inch) diameter, 130-km (82-mi) long pipeline from the four Val Verde gas treatment plants to reconnect this supply of anthropogenic CO_2 to EOR fields in the Permian basin (Petroleum Engineer International, 1998). The Petro Source pipeline initially carries 2 million m^3/day (70 MMcfd) of CO_2, with capacity to transport up to 3.5 million m^3/day (125 MMcfd).

CO_2-EOR Performance. Significant EOR was achieved at SACROC from 1981 onwards (Figure 2-7). This followed a 10-year period during which CO_2 injection (around 150 MMcfd) and water injection (rising from 200,000 to 600,000 BWPD) failed to avert a decline in oil production. The first part of the recognizable period of EOR (1981-1984) coincides with a sharp increase in water injection rate from 600,000 to over one million BWPD. It is not clear, therefore, how much of the incremental oil generated during this period is due to the more aggressive water flooding or to a delayed CO_2 effect. On the other hand, post-1984 water injection steadily declined to one quarter of its peak rate, and much of this incremental oil can be attributed to CO_2-EOR.

Carbon dioxide injection rates were much higher during the early stages of the project at about 5.1 million m^3/day (180 MMcfd), but declined to 1.7 million m^3/day (60 MMcfd) by 1995. A cumulative, gross total of just over 30 x 10^9 m^3 (1 Tcf) of injected CO_2 contributed to recovery of 69 million bbl of incremental oil. By 1995 the cumulative gross injection/production ratio (including re-injection) had declined to (a still relatively high) 15 Mcf/BO.

EOR performance could be considerably better within certain portions of the SACROC Unit, particularly areas where waterflooding had been mature by the time CO_2 injection was started. In one area (603 acres, 24 wells), injection during the first 5 years led to an incremental recovery of 10% of the original oil in place (OOIP); gross CO_2 utilization was 9.5 Mcf/bbl and a net of only 3.2 Mcf/bbl. Results over nearly 7 years in a larger area (2,700 acres, 100 wells) show incremental recovery of 7.5% of OOIP; gross and net CO_2 utilization were 9.7 Mcf/bbl and 6.5 Mcf/bbl, respectively. Pennzoil estimates that CO_2 flooding will recover approximately 8.0% of original oil in place. Pennzoil has not undertaken studies to estimate CO_2 sequestration at the SACROC Unit.

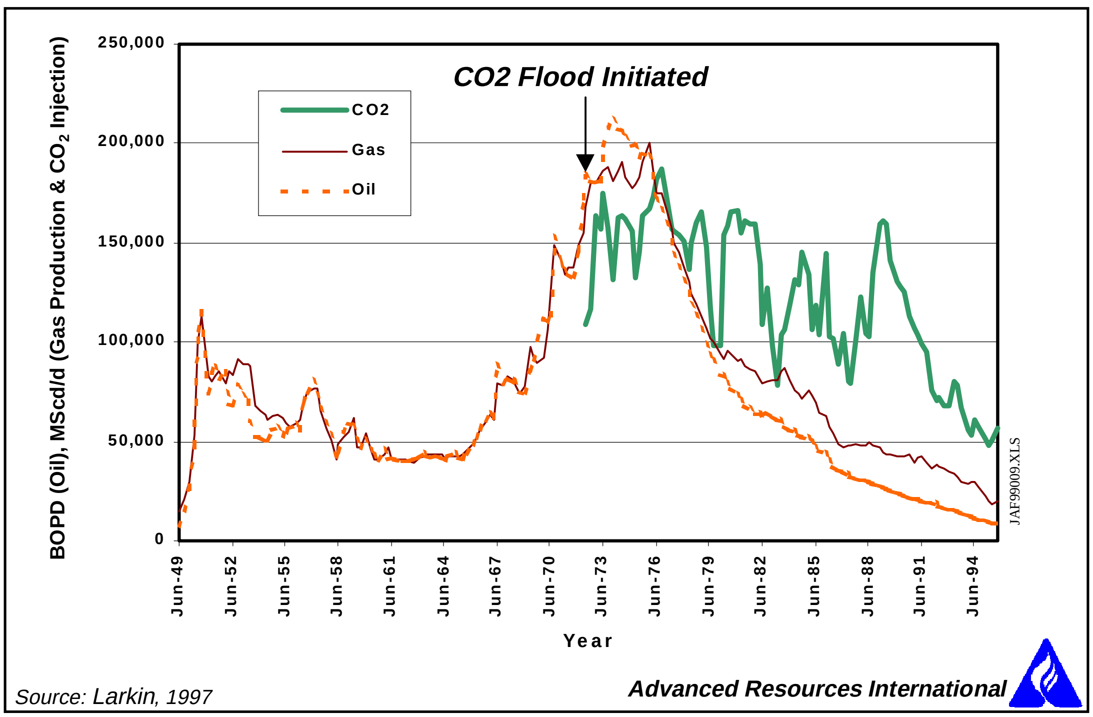


Figure 2-7
SACROC Unit Production and CO_2 Injection Data

Wasson-Denver Unit (Altura [Shell/Amoco])

(Kittridge, 1992; Hsu et al., 1997; Oil & Gas Journal, 1998; Ward and Cooper, 1995; operator discussions)

Background. Altura, a local Permian basin joint venture between Shell and Amoco, operates the Wasson-Denver Unit project, one of the world's largest and longest-term CO_2 floods (Table 2-6). The Wasson-Denver Unit covers about 114 km^2 (28,000 acres) in Yoakum and Gaines counties, western Texas (Map 2-2). Light oil is produced from the Denver Unit of the dolomitic San Andres Formation at a depth of about 1,500 m (5,000 feet). Lateral reservoir continuity is considered good across the average injector-producer distance of 300 m (1,000 feet). The Denver Unit is located at the shallowest structural level within the Wasson field. The field has an original natural gas cap up to 100 m thick that has a significant impact on its CO_2-flood performance. Primary oil production dates back to 1936. Water flood operations commenced in 1965, while miscible CO_2 injection was initiated in mid-1983 and increased markedly following completion of the Cortez pipeline in mid-1984 (Figure 2-8).

Table 2-6
Key Parameters of the Altura (Shell/Amoco) Wasson Denver Unit CO_2-EOR Project, Permian Basin, U.S.A.

Parameter	Metric Units	English Units
Depth	1,585 m	5,200 feet
Oil Gravity	0.86 g/cc	33° API
Current EOR Area	115 km^2	27,848 acres
Number of Wells	735 Producers, 365 Injectors	
Original Oil in Place (OOIP)	335 million m^3	2.10 billion barrels
Current EOR Production	4,880 m^3/day	30,700 BOPD
Current Cumulative EOR Production	9.7 million m^3	60.0 million barrels
Estimated Ultimate EOR (%OOIP)	56 million m^3 (16.6%)	348 million barrels (16.6%)
Current Gross CO_2 Injection Rate (1998)	12.1 million m^3/day	426 MMscfd
Cumulative Net CO_2 Injection (1998)	43 x 10^9 m^3 (0.08 Gt)	1.5 Tcf
CO_2 Source	Bravo and McElmo Domes (Natural)	

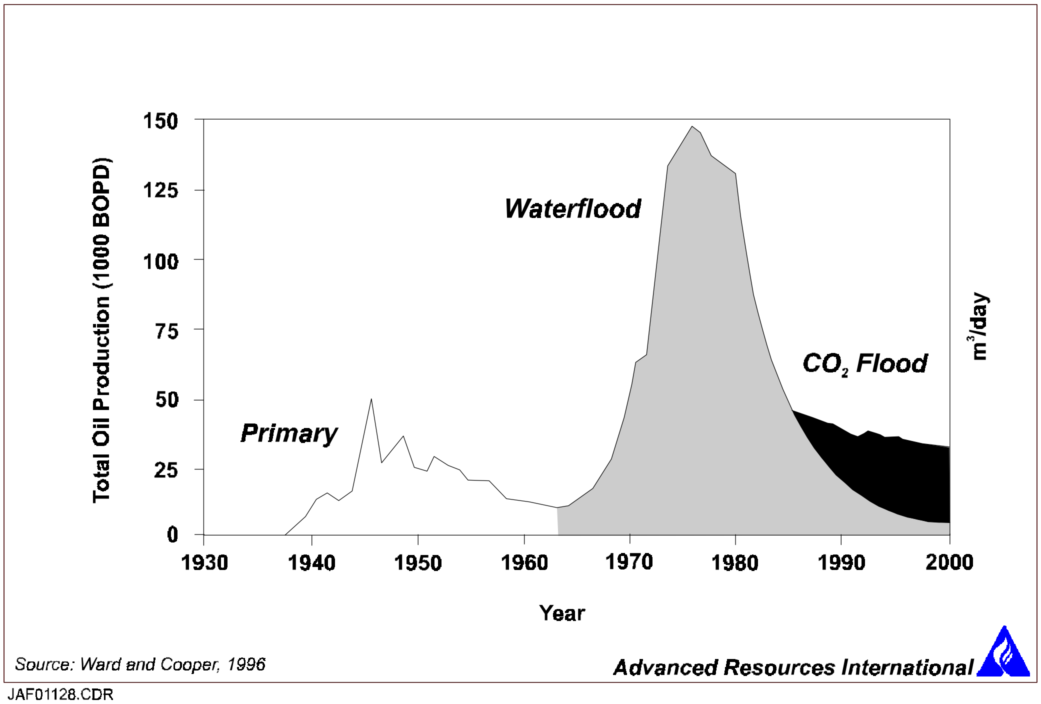


Figure 2-8
Oil Production History at Shell's Wasson Field, Denver Unit, Permian Basin, West Texas

Carbon dioxide injectant is supplied to the Wasson-Denver Unit via the 900-km (560-mi) long, 76-cm (30-in) diameter Cortez pipeline. The Cortez line is operated by Shell CO_2 Co., Ltd. and is supplied by the McElmo Dome field in southwestern Colorado, which is a naturally occurring CO_2 deposit. During 1998, gross CO_2 injection rates at Wasson-Denver Unit averaged 9.1 million m^3/day (320 MMscfd). This rate is down considerably from the 12.1 million m^3/day (426 MMscfd) level during 1996, as part of the planned tapering of this maturing WAG. Approximately half of this CO_2 injectant is purchased from the Cortez supply pipeline, while the other half is sourced internally by recycling CO_2 that has broken through to the field's production wells (such CO_2 breakthrough is a normal occurrence in an EOR field). The Wasson-Denver Unit is operated as a water-alternating-gas (WAG) flood.

CO_2-EOR Performance. The Wasson-Denver Unit CO_2 flood comprises an array of 365 injection wells and 735 producing wells. Figure 2-8 shows the long-term oil production history since discovery in 1937, illustrating clearly the three distinct phases of recovery methods used at the field. Primary oil recovery took place during 1937-1963. Water flooding beginning in 1964 generated a significant increase in oil recovery, which began to drop off sharply after 1980.

The onset of CO_2 flooding in 1983 was accompanied by a sharp decline in water injection. Altura's analysis indicates that most of the oil production during the first few years of the CO_2 flood continued to be attributed to the base waterflood. Enhanced oil recovery first became evident in mid-1985 and steadily increased to the end of 1996, as demonstrated by the widening differential between the actual oil production curve and the projected base decline curve. The CO_2 flood was later expanded during 1989 into the western half of Wasson-Denver Unit.

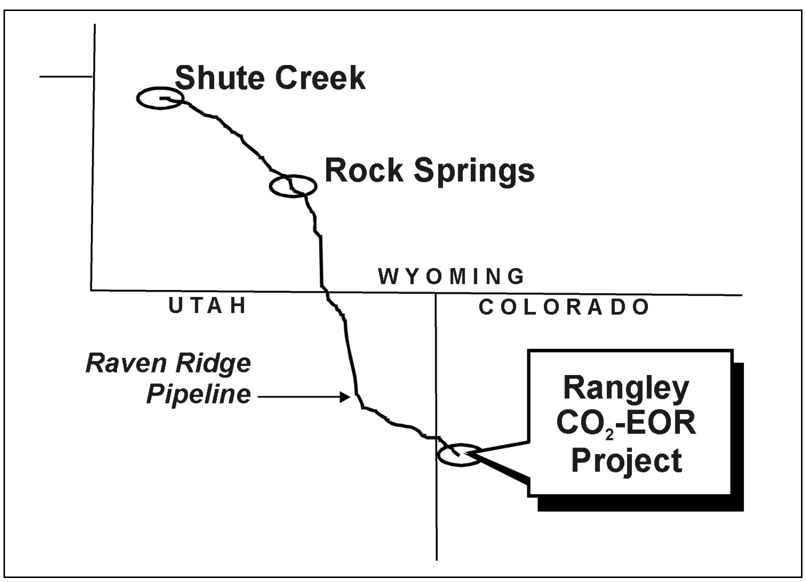
CO_2 injection rates during most of this period were fairly steady at around 13 million m^3/day (450 MMcfd), while EOR production increased to nearly 5,000 m^3/day (30,700 BOPD) by 1998, currently the highest of any active CO_2 flood. The cumulative net purchased CO_2 injected/EOR produced ratio at Wasson-Denver Unit to date is a relatively high 1,950 m^3/m^3 (11 Mscf/BO). However, Altura forecasts that CO_2 flooding eventually will recovery a total of (348 million barrels) or approximately 16.6% of original oil in place by the conclusion of this project. Thus, the net CO_2/EOR ratio is expected to decline to an ultimate 950 m^3/m^3 (5.34 Mscf/BO) at the end of the project, which is about typical for the Permian basin. Altura has not conducted specific studies of CO_2 sequestration at the Wasson-Denver Unit.

Rangely Weber Sand Unit (Chevron U.S.A. Production Co.)

(Jonas et al., 1990; Brock and Bryan, 1989; Hild and Wackowski, 1998; Wackowski, 1997; and Oil & Gas Journal, 1998; operator discussions)

Background. The Rangely Weber Sand Unit CO_2 flood operated by Chevron covers 15,000 acres in northwestern Colorado (Map 2-3; Table 2-7). It is the largest oil field in the U.S. Rocky Mountain region in terms of daily and cumulative oil production, and is currently the world's third largest CO_2 flood. The project is developed as a miscible water-alternating-gas (WAG) flood. Although considered very profitable overall, the Rangely project is approaching the end of its planned life. Chevron plans to reduce and eventually cease new CO_2 purchases.

CO_2 injection and enhanced oil recovery takes place in the Weber Sandstone, a 200-m (675-ft) thick sequence of interbedded eolian sandstones and mixed fluvial siltstones, shales, and sandstones of Pennsylvanian-Permian age. Five major fluvial shale breaks have been identified within the reservoir. These shale layers generally act as effective vertical permeability barriers that stratify the reservoir into six major producing zones. Formation depths of about 1,800 m (6,000 ft) and the relatively light oil are suitable for CO_2 miscibility.



Map 2–3
Location of Rangley Weber CO_2-EOR Project, Colorado, U.S.A.

Table 2-7
Key Parameters of Chevron's Rangely Weber Unit CO_2-EOR Project, Colorado, U.S.A.

Parameter	Metric Units	English Units
Depth	1,680 to 1,980 m	5,500 to 6,500 feet
Oil Gravity	0.85 g/cc	35° API
Current EOR Area	62 km^2	15,000 acres
Number of Wells	378 Producers, 259 CO_2 Injectors	
Original Oil in Place (OOIP)	300 million m^3	1.88 billion barrels
Current EOR Production	2,210 m^3/day	13,881 BOPD
Current Cumulative EOR Production	10.0 million m^3	62.0 million barrels
Estimated Ultimate EOR (%OOIP)	22 million m^3 (7.2%)	136 million barrels (7.2%)
Current Gross CO_2 Injection Rate	4.4 million m^3/day	157 MMscfd
Cumulative Gross CO_2 Injection (1996)	23 x 10^9 m^3 (0.04 Gt)	0.811 Tcf
CO_2 Source	Exxon Labarge Gas Processing Plant (Anthropogenic)	

CO_2 injectant at Rangely is supplied via pipeline from Exxon's La Barge natural gas processing plant in southwestern Wyoming. The massive Labarge gas plant removes naturally occurring CO_2 from natural gas production in this region, enabling the latter to meet pipeline corrosion specifications. Because this byproduct CO_2 otherwise would be emitted to the atmosphere – in fact most of the waste CO_2 at this gas plant still is vented – the injectant at the Rangely Weber Unit may be considered to be anthropogenic sourced. The delivered supply cost for high-pressure CO_2 at this field is not known, but is estimated to be in the range of \$0.02/m^3 (\$0.50/Mcf).

The Rangely Weber sandstone represents a different reservoir type (clastic) compared with the carbonate reservoirs typical of the Permian basin CO_2 floods, while the tectonic environment is also distinctly different (Rocky Mountain thrust belt vs. Permian basin passive shelf). This makes the Rangely EOR case study a useful complement to the Permian basin examples. We used the well-documented Rangely Weber EOR project to develop a methodology for estimating CO_2 sequestration in depleted oil fields, discussed in Chapter 4.

CO_2-EOR Performance. The CO_2 flood comprises an array of 259 CO_2- and 21 water-injection wells and 204 producing wells, developed on an average 0.08 km^2 (20-acre) well spacing. Carbon dioxide injection was initiated in late 1986 as part of a WAG flood. It was anticipated in 1989 that gross CO_2 utilization would be 9 Mcf/bbl with a net of 4-6 Mcf/bbl, but actual utilization has been slightly higher. During the first ten years of CO_2 flooding (1986-1996), 674 Bcf of gross carbon dioxide was injected (317 Bcf net purchases) to produce 51 million bbl of incremental oil. Gross CO_2 utilization was 13.2 Mcf/bbl (6.2 Mcf/bbl net). Mid-1997 CO_2 purchases were 1.6 million m^3/day (55 MMcfd). Ultimate CO_2 purchases are predicted to be 13.4 billion m^3 (472 Bcf), for a highly favorable final net CO_2/oil ratio of 3.47 Mcf/BO.

A continual problem at Rangely Weber field has been maintaining CO_2 conformance, which is the ideal condition under which injectant flows evenly throughout the reservoir, achieving maximum oil sweep and recovery. In fact, CO_2 flows very unevenly through the Rangely Weber field (and many other CO_2 floods). This results in rapid effective sweep of oil in highly permeable zones, while the tighter zones remain unswept. Over time, injected CO_2 simply continues to flow through the permeable but barren “thief” zones, leading to premature CO_2 breakthrough at the production wells and bypassing considerable oil in place. (Rangely Weber field is further analyzed in Chapter 4 as a benchmark for CO_2 sequestration in depleted oil fields.)

3

ELECTRICAL POWER USAGE AT CO_2-EOR PROJECTS

Introduction

Most EOR production technologies (CO_2, thermal, etc.) share a common profile of electric power demand, although the intensity of electricity demand can vary widely depending on the application. Major power demand items include pumping fluid from the production well, separation and treatment of produced fluids, water injection/disposal and transportation. Some of the useful "rules of thumb" for power demand at EOR projects include:

Current Status:

- Roughly 5 hp is required to move 1 BOPD in CO_2-EOR projects, compared with less than 1 hp/BOPD for thermal EOR.
- 1 hp costs about $215 to run annually at typical electricity prices of $0.032/kw-hr.
- The current installed power capacity of CO_2-EOR projects in the Lower-48 States is estimated at approximately 963,000 HP or about 788 MW.
- At electricity costs of $0.025 to $0.05/kw-hr, this translates to annual electricity expenses of about $165 million.

Growth Potential:

- Power demand growth is currently estimated at about 50,000 to 100,000 hp per year, equivalent to about 40 MW/year.
- The value of this growth is estimated at about $10 to $20 million/year.
- EOR development could expand if electricity prices fall in response to deregulation.
- Growth could also accelerate significantly if CO_2 sequestration credits are available, if emission restrictions limit the use of gas compression.

Regulated vs. Deregulated Tariffs:

Under the regulated market, Table 3-1 summarizes the computation of tariffs for typical EOR power consumers:

Table 3-1
Regulated Tariffs for Typical EOR Power Consumers

Tariff Item	Unit Charge	Monthly Charge
Customer Charge	$500/month	$500
Demand Charge	$3 to $15/kW	$48,000 to $240,000
Energy Charge	$0.01 to $0.03/kWhr	$110,000 to $330,000
Fuel Adjustment	$0.01 to $0.02/kWhr	$109,000 to $220,000
Facility Rental	$2 million per 60	$33,300

However, most states are in the process of deregulating the electricity industry. For example, Oklahoma is scheduled to be competitive by July 2002. Prices could be commodity-based using power exchanges, NYMEX contracts, price indices, or derivative products. However, some experts believe that prices may not decrease even after stranded costs are worked off.

Lifting

One of the largest components of electricity consumption in EOR fields is for driving the pumps that lift oil and water from the well and move it to processing and distribution systems. Along with approximately 10,000 EOR production wells, a total of more than 400,000 conventional oil and gas production wells in the U.S. operate using beam-pump artificial lift.

It is expected that expansion of EOR flooding will lead to commensurately higher power demand. However, increasing penetration of simple well operating technology (timer-controlled and multi-phase pumps) could more than offset this anticipated increased demand.

Timer-Controlled Pumps. Many EOR production wells are equipped with pumps that have a capacity greater than the well's production capacity. The pumps in many such wells are run continuously on 24-hour/day periods, even though a shorter period is often sufficient to "pump off" the fluids that flow into the well. Running the pump after the well is pumped dry not only wastes electricity, it can also damage the pumping equipment and lead to higher maintenance costs.

To reduce both electricity and maintenance costs, EOR operators are increasingly equipping their production wells with simple timing or governing devices that shut down the pump when it is not needed (McCoy et al., 1999). Often, timers are set to run the pump at non-peak times. Timers are simple and inexpensive, at under $200 per well, but must be continuously reset to correct for optimum operations. Pump-off controls are more costly, $500 to $5,000 per well, but has the advantage of self-correcting for well performance.

Table 3-2 shows an example of electricity costs for a typical EOR production well, comparing a well with and without pump-off controls. The following operational assumptions were made for this well:

- 30-HP motor.
- When pump is full, approximately 60% loaded (0.6 x 30 hp x 0.746 kw/hp = 13.4 kw).
- When pump is 40% full, approximately 45% loaded (0.45 x 30 x 0.746 = 10.1 kw).
- The pump is only needed 40% of the time to remove all fluids from the well bore.
- Electricity consumption charge of $0.05/kw-hr and $8/kw demand charge. (The author did not take into account off-peak rates, which could produce greater savings.)

Table 3-2
Comparison of Electricity Costs for Lifting Pumps

Pump Motor Operation	Consumption Charge ($)	Demand Charge ($)	Total Charge ($)
Continuous	363	108	471
40% With Long Cycle	193	108	301
40% With 15-min Timer	193	43	236

Using these assumptions, the most efficient case would be to operate the pump only 40% of the time with a 15-minute timer. Such a pump would operate for 6 minutes, followed by a 9-minute off cycle. Assuming the demand charge is based on the average power consumed within a 15-minute period, the demand charge would be reduced to 40% of $108, or only $43. The use of pump timers reduces total electricity costs under this scenario from $471/well/month to only $236/well/month, a savings of about $235/month.

Considering that at least several thousand EOR production wells could be converted to pump timers, this equates to a total avoided electricity cost in the neighborhood of $10 to $50 million annually. Applying this simple technology to one hundred thousand of the non-EOR production wells could raise total savings to $1 billion/year.

Multi-Phase Pumps with Variable Frequency Drives. Conventional pumps can only handle fluids in one (liquid) phase. However, newer multi-phase pumps are an increasingly attractive alternative for moving fluids from production wells to a centralized production facility, at lower overall costs. These pumps simplify production operations by boosting full well-stream flows, while replacing the separation, gas compression, tank storage, flaring, and liquid pumping that formerly was required (Butler and Curtis, 1999).

Of the total 150 multi-phase pump applications, most are twin-screw pumps. Progressive cavity and helico-axis pumps have also been installed for multi-phase operation. These pumps often incorporate variable frequency drives that allow for additional operational flexibility. *It appears* *that increased use of multi-phase pumps will reduce power consumption by EOR fields, with about half the power operating costs of conventional pumps.* On the other hand, the decreased operating costs associated with this technology could help promote new or expanded CO_2 flooding, thereby increasing power demand.

Multi-phase pumps have several advantages over conventional pumping technology:

- Reduce back pressure on oil and gas wells, which can increase production rates.
- Boosts pressure between an oil and gas field and the central processing facility.
- Boosts pressure at a gas processing facility where liquids are present.

Weatherford is a leading manufacturer of multi-phase pumps. Texaco and Chevron have been two of the foremost users of multi-phase pumps, including two pumps installed at the Duri steamflood EOR field in Indonesia. One of the few public examples of an application of multi-phase pumps is for a medium-sized conventional oil and gas field in Western Canada operated by Mobil (Wyborn, 1999). This application increased oil and gas production by 255 BOPD and 2.5 MMcfd, respectively. Capital costs were by an unspecified amount. Engineering and procurement for this fast-tracked project was 4.5 months.

The capital costs of multi-phase pumps typically are about 55% of the cost for a conventional twin-pump system of equivalent horsepower. In addition, power operating costs are about 45% to 50% of conventional systems.

Recompression

In an EOR project, the production well usually produces much more than simply crude oil. Methane and heavier hydrocarbon gases, carbon dioxide, H_2S, N_2, and other constituents are typically produced along with crude oil. Usually, the produced natural gas and CO_2 are recycled by re-injection into the EOR flood. Produced natural gas may also be sold. Before this can happen, however, the typically low-pressure produced gas must first be recompressed to field or pipeline levels. Table 3-3 shows typical compression parameters for a CO_2 flood.

Table 3-3
Typical Compression Parameters at Breakthrough for CO_2-EOR Project

Parameter	Value
CO_2 Concentration	85% to 90%
H_2S Concentration	2% to 3%
Inlet Pressure	15 psig
Outlet Pressure	1,750 psig
HP per MMscfd	300
Stages of Compression	4

Emissions. One of the key factors in selecting electric vs. gas-fired compression equipment is emissions. Auxiliary equipment, such as dehydrators and flare stacks, must also be considered in evaluating total facility emissions. In Texas, most grass-roots facilities can be exempted during the initial start-up phase (Standard Exemption), but permitting will be required as the facility and emissions increase in size. Larger facilities will eventually be impacted by Title V air quality regulations.

Gas Engine vs. Electric Motor. One of the first decisions to be made in designing the compression is the choice of driver. In some cases, the choice is obvious: some areas lack natural gas fuel or electric power at the required voltage. But where both drivers are available, natural gas fuel is generally significantly cheaper and operationally more flexible than electric power. This is a major disadvantage that electric power providers need to overcome.

However, electric powered compressors have the upper hand in emission constrained environments. Further marketing in roads may be possible if less costly variable-speed electric compressors can be developed. Some of the key issues that operators first consider when selecting the drive for compressors include:

- Is clean, dry natural gas available with a minimum heat content of 950 Btu/Mcf and minimum pressure of 50 psig?
- Is there a reliable electrical source available nearby with at least 4,160 volts, 3 phase, and 60 Hz service?
- If both drivers are available, then the comparative cost of natural gas vs. electricity must be evaluated on a $/hp basis.

The comparison of relative costs of natural gas vs. electricity must consider capital and operating costs, reliability, emissions, flexibility, maintenance costs, and other factors. Some of the key comparisons to be made are illustrated for a 3,000-hp compressor example in Table 3-4.

- The capital costs of electric driven compressors are typically 30% less than for gas engine driven compressors.
- However, natural gas fuel is generally much less expensive than electric power. The example provided shows that the energy costs for natural gas gas-fired compression are approximately half of those for electric compressors. In such cases, electricity may still have an edge in superior emissions, reliability, and maintainability.
- Electric compressors have a slight edge over natural gas compressors in terms of mechanical availability, 98% vs. 97%, respectively.
- Maintenance costs for electric compressors are lower. Furthermore, natural gas compressors are more susceptible to H_2S contamination in the fuel stream, requiring more frequent changes in lubricating oil.
- The volume of gas handled over the life of an EOR project can vary widely. Gas driven compressors generally are more flexible in handling changes in gas volumes compared with constant-speed electric driven compressors. Variable-speed electric compressors are currently perceived by field operators to be prohibitively expensive.

Table 3-4
Comparison of Natural Gas Fuel vs. Electric Power for Compression

Parameter	Natural Gas Compressor	Electric Power Compressor
Assumed Size of Compressor	3,000 hp	3,000 hp
Mechanical Availability	97%	98%
Capital Unit Costs	$650/hp	$450/hp
Capital Costs	$1,950,000	$1,350,000
Fuel/Energy Required	10 MMscfd @ $2.00/Mscf	$0.04/kw-hr
Annual Gas/Electric Power Cost	$394,200	$784,195
5-Year Discounted Full-Cycle Costs*	$3,593,761	$4,619,988

* Note: Useful life is generally much longer than 5 years, assuming normal overhaul. Maintenance and overall costs are not accounted for in the calculation, but usually are higher for gas drive.

Opportunity. Electric power providers will need to stress the reliability, maintainability, and lower emissions of electric drive compared with natural gas drive. Electric power does have the edge in lower up-front capital required. Unfortunately, in response to the higher capital costs of natural gas compression, many EOR operators are shifting to outsourced (leased) compression. This reduces the up-front capital required, in what already is a very capital intensive project; facility engineering and construction costs also can be outsourced rather than paid up-front. In some lease situations, the operator receives “free” natural gas to drive the compressors and would be unlikely to switch to electric drive.

Dehydration and CO_2 Separation

Most natural gas pipelines have quality specifications that limit the concentration of certain contaminants, such as water and carbon dioxide (Table 3-5). These contaminants must be stripped out of the produced gas stream to permit sales of natural gas through the pipeline.

Once breakthrough occurs in an EOR project, the produced CO_2 must be separated from the produced natural gas for sales (not necessary if the gas stream is simply re-injected).

Table 3-5
Typical Pipeline Specifications for Contaminants

Constituent	Specification
Water	7 lbs/MMscf
CO_2	3% by Volume
H_2S	4 to 16 ppm
N_2	4% Total Inerts (+CO_2)

Dehydration. Removal of water vapor from natural gas is required to prevent corrosion in the pipeline as well as the formation of gas hydrates. The water limit is typically 7 pounds water per MMscf of gas, although most producers design their dehydration to meet a safety target of 4 lbs/MMscf. Absorption of water by contact with glycol is used almost exclusively in EOR projects. In addition, membranes are currently being tested and show promise for dehydration applications.

Membranes. The most common CO_2 specification is not greater than 3% by volume. However, in recent years this specification has been reduced to 2% in many pipelines and as low as 1% in some. Membrane systems are most commonly used for CO_2 separation. Membranes can be manufactured using a variety of polymers and are selective for various gas components.

Membrane systems run on high-pressure gas streams, typically around 500 psi. They require 2 to 4 stages to reduce the CO_2 concentration from 50%-80% in the input stream to less than 10% in the residue. The compression costs discussed earlier in Chapter 3 include electricity to drive membrane systems.

Ryan Holmes. This method is most useful for separating CO_2, while simultaneously recovering natural gas liquids (NGL). Heavy (C4+) hydrocarbons are added to permit extractive distillation of these components.

4
SEQUESTERING POWER PLANT FLUE GAS CO_2 IN EOR FIELDS

Overview

Within OECD countries, including the United States, there is an inexorable trend towards limiting anthropogenic emissions of carbon dioxide and other gases suspected of causing global warming. The power generation industry of the U.S. – heavily dependent on coal, natural gas and other fossil fuels – is a major emitter of CO_2. Combustion of fossil fuel generates an estimated 2.7 x 10^9 (gigatonnes or Gt) of CO_2 per year in the U.S. and a total 6.6 Gt/year worldwide.

Power generation companies have three ways of dealing with CO_2 emissions. First, they can reduce emissions through reduced power generation or, preferably, through increased efficiency of power generation. Second, they can engage in, or compensate another entity that engages in, CO_2 emission reduction activities, such as reforestation. These first two options are already widely performed.

Third, power generators can dispose of waste CO_2 directly by injecting it into depleted oil fields for EOR (or into gas or coal reservoirs). The key challenge to utilizing flue gas is that CO_2 concentrations are relatively low (about 5 to 10% by volume) and it contains water, sulfur and other constituents that are potentially harmful to underground petroleum reservoirs. CO_2 first would have to be captured and purified from flue gas, then compressed and transported to the oil field for injection and disposal. Power plant flue gas has not yet been used commercially as EOR injectant. However, more concentrated (and thus lower cost) waste CO_2 from fertilizer or gas processing plants is routinely used in many EOR projects. (Chapter 6 discusses enhanced coalbed methane recovery, a process in which flue gas may be used with minimal pre-processing.)

Disposal of CO_2 captured from flue gas in EOR fields is an attractive option that is currently under consideration by a number of power producers and oil companies. Following more than a century of intensive petroleum exploitation, thousands of oil and gas fields in the U.S. are fast approaching or are already past their economically productive life. Many of these fields could act as effective storage sites for anthropogenic CO_2, such as power plant emissions, that would otherwise be emitted to the atmosphere. As discussed earlier in Chapter 2, under certain favorable reservoir conditions, injection and storage of CO_2 is part of routine (and profitable) enhanced oil recovery operations. The CO_2-EOR projects of the Permian basin in western Texas and eastern New Mexico are excellent examples.

Advantages/Disadvantages of CO_2 Storage in Depleted Oil and Gas Fields

Sequestration of CO_2 may be technically feasible within a variety of reservoir settings, including depleted oil and gas fields, saline aquifers, deep coal seams, and even injection into the deep ocean. Each of these methods holds potential for effective sequestration under certain surface and sub-surface conditions. However, storage within depleted oil and gas fields holds significant comparative *advantages*, including:

- **Beneficial Oil Recovery.** Injection of CO_2 in depleted oil fields can enhance oil recovery, which can help offset the costs of injection. This is not true for sequestration in saline aquifers, depleted natural gas fields, or the deep ocean. In certain favorable reservoir settings, as currently in the southwestern United States, CO_2 sequestration using lower-cost anthropogenic CO_2 sources (such as natural gas plant waste streams) can actually generate significant net profits, even without the benefit of emission reduction credits. Although the current high cost of capturing and treating relatively low-concentration flue gas CO_2 probably would make EOR subeconomic, without credits or incentives *the EOR disposal method still would have relatively low full-cycle costs.*
- **Data/Understanding.** The geologic and reservoir properties of depleted oil fields generally are much better characterized than those of commercially non-productive strata (such as saline aquifers). Extensive well and seismic data are collected during normal petroleum field exploitation; these data provide an invaluable source of understanding about depleted reservoirs. In contrast, deep saline aquifers, sub-sea settings, and even most coalbed methane areas tend to be poorly surveyed by well and seismic data. This increases the operating costs and leakage risks of CO_2 sequestration in those settings.
- **Infrastructure.** Certain components of existing petroleum infrastructure (pipelines, wells, offshore platforms, etc.) within many depleted oil fields may be adapted for CO_2 storage purposes, reducing the effective capital costs of CO_2 sequestration.
- **Integrity of Storage**. Disused natural gas fields and most oil fields are proven gas traps, ensuring that injected CO_2 would be sequestered over geologic time (millions to hundreds of millions of years). In contrast, deep ocean injection may only temporarily store CO_2 for hundreds of years (the ocean circulation cycle is approximately 200 years). Similarly, because aquifers are dynamic systems, much of the injected CO_2 would eventually escape over a moderately long time frame (thousands of years). It is likely that EOR fields will be able to obtain verifiable credits for long-term sequestration, whereas ocean and aquifer storage sites will have greater difficulty.

On the other hand, the use of depleted oil fields for CO_2 sequestration may face several potential *limitations* compared with aquifer or other geological disposal options. These disadvantages include:

- **Proximity to Power Plant.** Aquifers are geographically more widespread than depleted oil and gas fields. Aquifers are more likely to be conveniently located close to large power plants. The solution is to transport CO_2 via long-distance pipelines. Such transport has been conducted commercially on a large scale for more than a decade in the southwestern U.S., mostly for naturally occurring, high-pressure CO_2 but also for anthropogenic waste CO_2 from gas processing facilities.

- **Organizational Conflicts.** There should be relatively few operational, legal, or other conflicts associated with CO_2 injection into non-potable aquifers. This is largely because currently there are no other commercial uses of saline aquifers. In contrast, significant conflicts would be expected between oil & gas operators or rights holders and power plants seeking to sequester CO_2. For example, under normal market conditions (i.e., no sequestration credits), an EOR operator focuses on maximizing oil production and minimizing production costs. *The operator's goal is to minimize CO_2 sequestration, whereas the power company's goal would be to maximize sequestration.*

Sequestration of CO_2 Within Enhanced Oil Recovery Projects

Storage of carbon dioxide is already taking place on a significant scale within commercial enhanced oil recovery projects that utilize CO_2 flooding technology. Indeed, sequestration occurs often at a net profit, with no targeted subsidy yet in effect. But how much of the injected CO_2 is actually sequestered, as opposed to merely cycled through the reservoir?

It appears that much of the stored CO_2 should be considered temporary, trapped within the reservoir pore space under pressure only during the active life of the EOR (approximately 5 to 50 years). Normally, decommissioning an EOR project involves "blowing down" reservoir pressure to maximize oil recovery. Operators consider injected CO_2 to be a valuable commodity, and they may re-use it for EOR at new fields, should recycling be an economically viable option. Alternatively, if no suitable EOR candidate can be found nearby, the CO_2 produced during blow down would simply be vented to the atmosphere.

To permanently sequester injected CO_2, operators would need adequate incentives to seal CO_2 in the depleted oil field and to monitor its continued presence. Such incentives could come in the form of financial credits provided by the power plant operator to qualifying CO_2 sequestration facilities. Nevertheless, regardless of how the field is decommissioned, a small but substantial fraction of injection CO_2 is likely to remain permanently sequestered within the reservoir, dissolved in immobile oil.

To date no individual CO_2-EOR project has been directly monitored or even indirectly assessed specifically to determine CO_2 sequestration. (Pan-Canadian's planned Weyburn field in Canada, and Norsk Hydro's proposed project at Grange field in the North Sea would be the first such overt EOR/sequestration projects.)

However, all CO_2-EOR operators maintain strict control and monitoring of CO_2 within the reservoir, for the simple reason that purchasing CO_2 is inevitably the single largest expense for an EOR project. Typically, CO_2 purchase/preparation accounts for about half of total capital and operating costs in an EOR project. Detecting and avoiding unnecessary venting or other loss of CO_2 from the reservoir is a constant concern of EOR field engineers. Vigilant recycling and re-injection of CO_2 is generally routinely performed at mature EOR floods.

To be sure, some venting of CO_2 is inevitable at various stages in the life of an EOR project. But venting is usually restricted to the early test stages of a project or in project expansions, before installation of recycling equipment is considered to be cost-effective, or later in mature floods during overhaul of recycling facilities.

Significantly, each of the approximately 79 individual CO_2-EOR projects currently in operation relies on revenues from oil (and sometimes natural gas) sales alone, which must offset the significant cost of purchasing CO_2 for injection. No CO_2-EOR project yet receives financial benefit in the form of monetary support, CO_2 sequestration credits, or even free or reduced-cost CO_2 supplies (there are, however, investment tax credits targeting EOR development itself that indirectly promote limited sequestration). Thus, the CO_2 sequestration currently taking place in depleted oil fields is independent of any environmental intent for reduced greenhouse gas emissions. Furthermore, it is reasonable to assume that CO_2 sequestration credits or other financial incentives, once in place, could substantially increase CO_2-EOR investment and production, with larger associated sequestration.

In most cases, sequestration-related incentives would be required to justify the opportunity cost of not utilizing the CO_2 at another EOR project, in addition to the direct costs of storing, monitoring and maintaining the CO_2 within the field after the EOR project is decommissioned.

CO_2 Injection, Recycling, and Sequestration Within EOR Projects

Publicly available data on CO_2 injection and cycling in depleted oil and gas fields is extremely limited. Oil and gas production regulations in the United States and many other countries require that production be reported to government oil and gas regulatory commissions regularly and in some detail. In contrast, most U.S. states (notably, Texas and New Mexico) do not require detailed records of CO_2 injected into an underground reservoir. For this study, a fragmentary picture of CO_2 injection in EOR projects was pieced together, based on detailed literature case studies and on information provided directly by operators. A few relatively well documented EOR projects served as benchmarks in establishing performance “rules of thumb” for CO_2 sequestration. We then extended our analysis to the universe of other less-documented depleted oil fields.

Figure 4-1 shows a schematic cross-section of a typical EOR project, illustrating the cycling of carbon dioxide within a flooded reservoir. Actual subsurface heterogeneity and physico-chemical interactions of CO_2 within the reservoir may result in far more varied flow than illustrated here, particularly for complex reservoirs or more sophisticated injection strategies (such as WAG, foam, or other techniques). However, in general the following processes affecting enhanced oil recovery and sequestration of CO_2 are common to most reservoirs:

- **CO_2 Injection:** Carbon dioxide, purchased from an underground CO_2 reservoir (natural source) or from a natural gas processing or fertilizer manufacturing plant (anthropogenic source), is injected into the reservoir at high pressures adequate to achieve miscibility. (In future projects, CO_2 extracted from power plant flue gas could be injected.)
- **Miscibility:** Oil within the reservoir swells with the introduction of CO_2, reducing the oil’s viscosity and improving its mobility.
- **Production:** Mobile oil containing dissolved CO_2 flows toward the low-pressure sink created by the production well, and is then pumped to the surface.

- **Recycling:** At the surface, carbon dioxide that has broken through is separated from the produced oil and, if economically feasible, processed using amine (DEA) treating, adsorption processes, extractive distillation techniques or membrane systems. All of these processes are electricity-intensive activities. The purified CO_2 is then recycled with purchased CO_2 down the injection wells.
- **Sequestration:** Some of the injected carbon dioxide dissolves into immobile oil resources, remaining trapped within the reservoir. Much of this CO_2 would be effectively sequestered, even after the field is decommissioned and “blown down.”
- **Storage:** As long as reservoir pressure is maintained, and the producing wells are shut in, CO_2 is “sequestered” (actually stored) within the pore space of the reservoir.
- **Emissions:** Although operators first plug all known oil wells that are not in operation within the field prior to commencing CO_2 injection, some emissions are almost inevitable from unidentified and poorly abandoned wells, behind poorly cemented casing, or other pathways (including natural fractures). In addition, operators knowingly vent a small volume of CO_2, usually in early stages before recycling facilities are economically justified or during overhaul of these facilities. For this study, we conservatively (from a sequestration point of view) assumed that 10% of net CO_2 purchases are emitted; the actual percentage may be much lower.

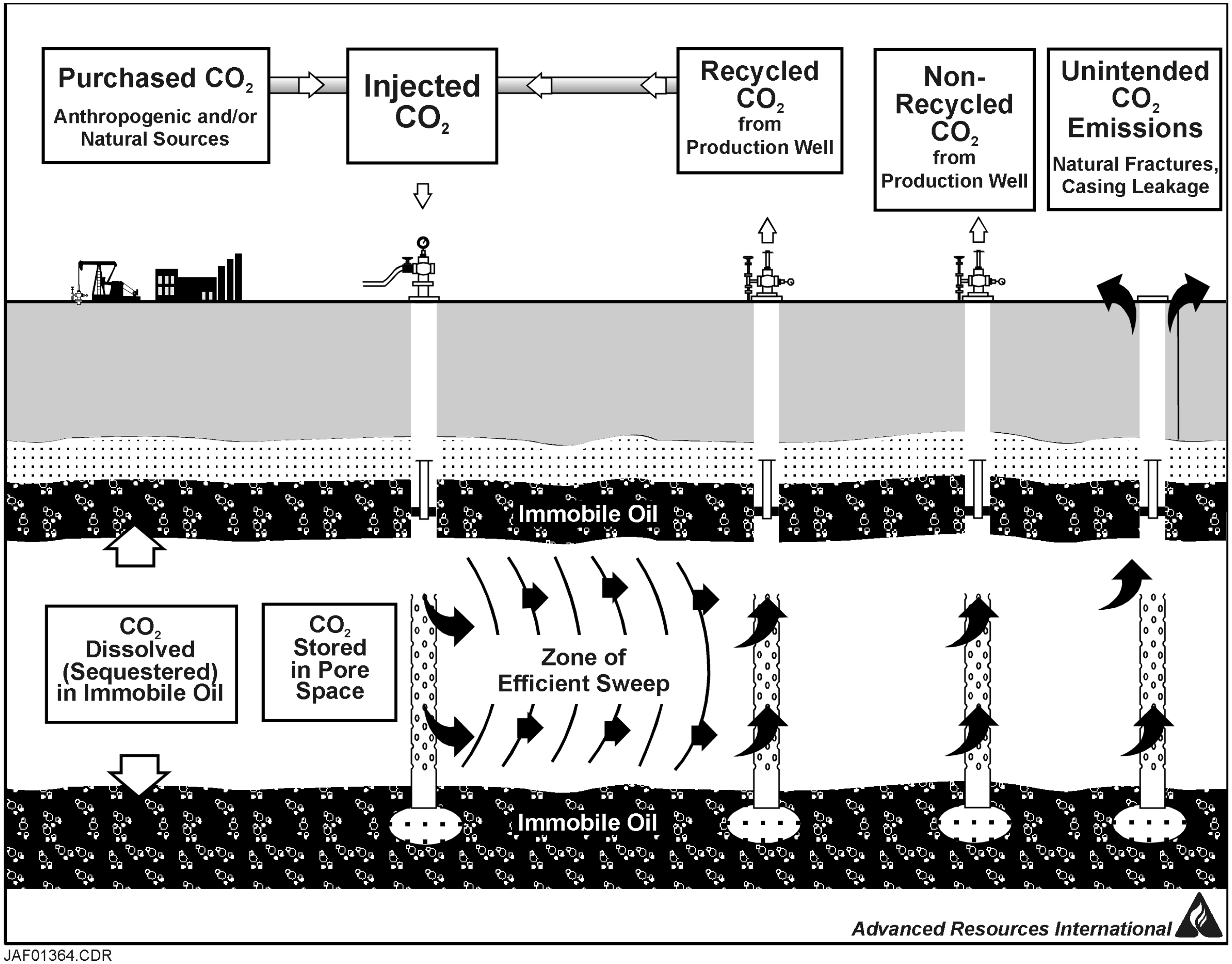


Figure 4-1
Schematic Cross-Sectional View of CO_2 Injection, Recycling and Sequestration Within an EOR Field

Sequestration Case Study: Rangely Weber Field

The Rangely Weber EOR project, which is operated by Chevron and located in northwestern Colorado, is one of the world's largest active CO_2 floods. It is also one of the most complete in terms of public documentation (see detailed case history in Chapter 3). The Rangely Weber project is mature and not currently undergoing major expansion, thus a steady-state analysis of CO_2 cycling can be made. Of particular analytical value, a relatively complete set of CO_2 and EOR information was obtained for current and future EOR operations at this field (Table 4-1). This information is sufficient to allow a first-order estimate of current and ultimate CO_2 sequestration at this field.

Table 4-1
Carbon Dioxide Injection, Recycling, and Sequestration at Chevron's Rangely Weber Field, Colorado, U.S.A.

	Current (1998)		Estimated Ultimate+ #		
CO_2 Volumes	**MMcfd**	**10^6 m^3/day**	**Tcf**	**10^9 m^3**	**Gt**
Gross CO_2 Injected	157	4.45	1.25	35.4	0.07
Recycled CO_2@	116	3.28	0.57	16.1	0.03
Net CO_2 Purchases	41	1.16	0.68	19.3	0.04
Less Venting/Emissions*	0 - 4	0 - 0.12	0 - 0.07	0 - 1.90	0.00
Net CO_2 Sequestered	**37**	**1.05**	**0.61**	**17.3**	**0.03**

+Gross based on Chevron's projected gross CO_2 injected to EOR ratio of 1,640 m^3/m^3 (9.2 Mcf/BO) and ultimate EOR reserves of 21.6 million m^3 (136 MMBO).
Net based on Chevron's projected net CO_2 injected to EOR ratio of 890 m^3/m^3 (5.0 Mcf/BO) and ultimate EOR reserves of 21.6 million m^3 (136 MMBO).
@ Not forecast by Chevron; determined by subtraction.
* Not previously documented for an EOR project; assumed here to be 10% of net CO_2 purchases.
Note: numbers may not add due to rounding.

Chevron purchases CO_2 from Exxon's La Barge natural gas processing plant, which removes natural CO_2 contaminate from methane gas. Thus, this project may be considered to be exclusively utilizing anthropogenic carbon dioxide. In fact, Rangely Weber is believed to be currently the largest single sequestration site of anthropogenic CO_2 in the petroleum industry. (Pennzoil's SACROC project, which employed anthropogenic-sourced CO_2 for over two decades, recently switched to natural CO_2 sources. By comparison, Statoil's Sleipner aquifer disposal project on the Norwegian continental shelf sequesters CO_2 at about one-quarter the rate of the Rangely Weber project.

As part of its EOR project development planning, Chevron has performed full-field reservoir simulation of the Rangely Weber unit. These simulations are based on detailed reservoir characterization and modeling that replicate the long-term underground flow of CO_2 within the reservoir and the enhanced oil recovery that can be expected. Although we do not have access to

Chevron's model, they have reported certain key data, conclusions and projections that allow us to estimate CO_2 sequestration. Figure 4-2 shows our interpretation of the **current** (1998) rates of CO_2 flow within the Rangely Weber sandstone reservoir, while Figure 4-3 shows the estimated ultimate consumption of CO_2 during the full life of the project.

During 1998, Chevron injected an average total of about 157 MMcfd of CO_2 into the Rangely Weber field (Figure 4-2). Most of the injected CO_2 dissolved into mobile oil within the main sandstone reservoir, and was carried along with the oil to the production wells. About 116 MMcfd of CO_2 was separated from the field's production wells and recycled through the injectors, accounting for about three-quarters of injected CO_2. An additional 41 MMcfd of CO_2, or about one-quarter of total injected volume, was purchased and blended with the recycled volumes. Given our assumption that an average 10% of net CO_2 purchases is lost to the atmosphere due to intentional and unintentional venting (probably much too high for a mature flood such as Rangely Weber), an estimated 4 MMcfd of CO_2 is emitted.

Thus, the **current** rate of CO_2 sequestration at Rangely Weber field is estimated at approximately 37 MMcfd. Some of this CO_2 may fill the hydrocarbon pore volume as oil is continually produced and removed from the reservoir, although the injected water more likely fills most of this new void space. Most sequestered CO_2 is probably dissolved in immobile oil that is not expected to be produced, and would probably remain in the reservoir after decommissioning.

The **ultimate** volume of CO_2 sequestration may also be estimated based on Chevron's simulation forecasts (Figure 4-3). Given Chevron's projected ratio of gross CO_2 injected to EOR production of 9.2 Mcf/BO, and the total EOR recovery for the project which they estimate at 136 MMBO, some 1.25 Tcf of CO_2 are estimated to be injected over the life of the project. Furthermore, given Chevron's projected net CO_2/EOR ratio of 5.0 Mcf/BO, ultimate sequestration of carbon dioxide is estimated to be about 680 Bcf, which is equivalent to approximately 0.03 Gt of CO_2.

Thus, in its lifetime, even one of the world's very largest CO_2-EOR projects would have only an extremely limited impact on atmospheric carbon dioxide levels. However, this level of CO_2 sequestration could be quite attractive to a large power producer burning fossil fuels. Given that hundreds of depleted oil fields exist in the United States and could be used or sequestration, this sink could make a significant reduction in CO_2 to the atmosphere.

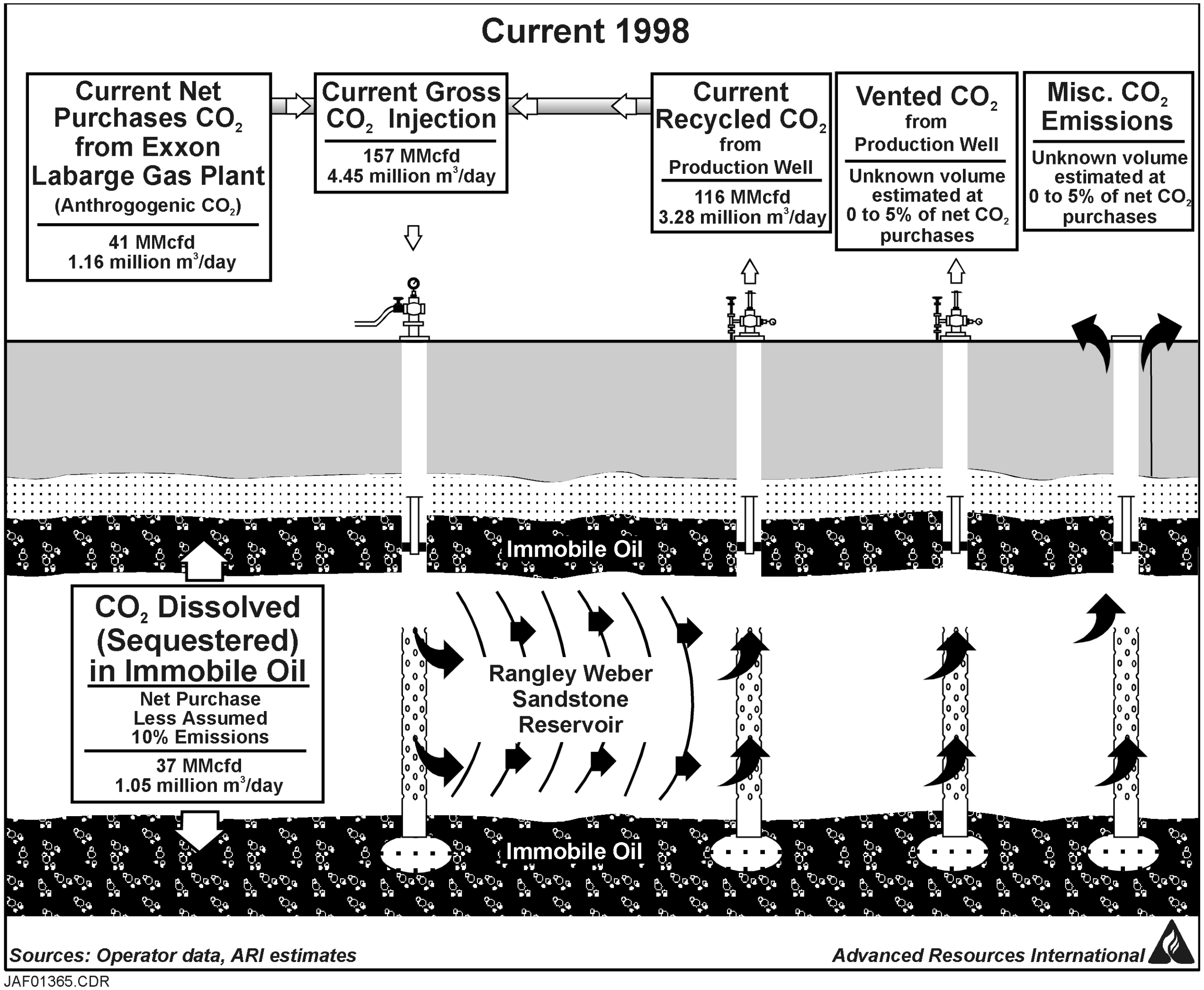


Figure 4-2
CO_2 Injection, Recycling and Inferred Sequestration at Chevron's Rangley Weber EOR Project, Colorado, U.S.A.: Current Rates (1998)

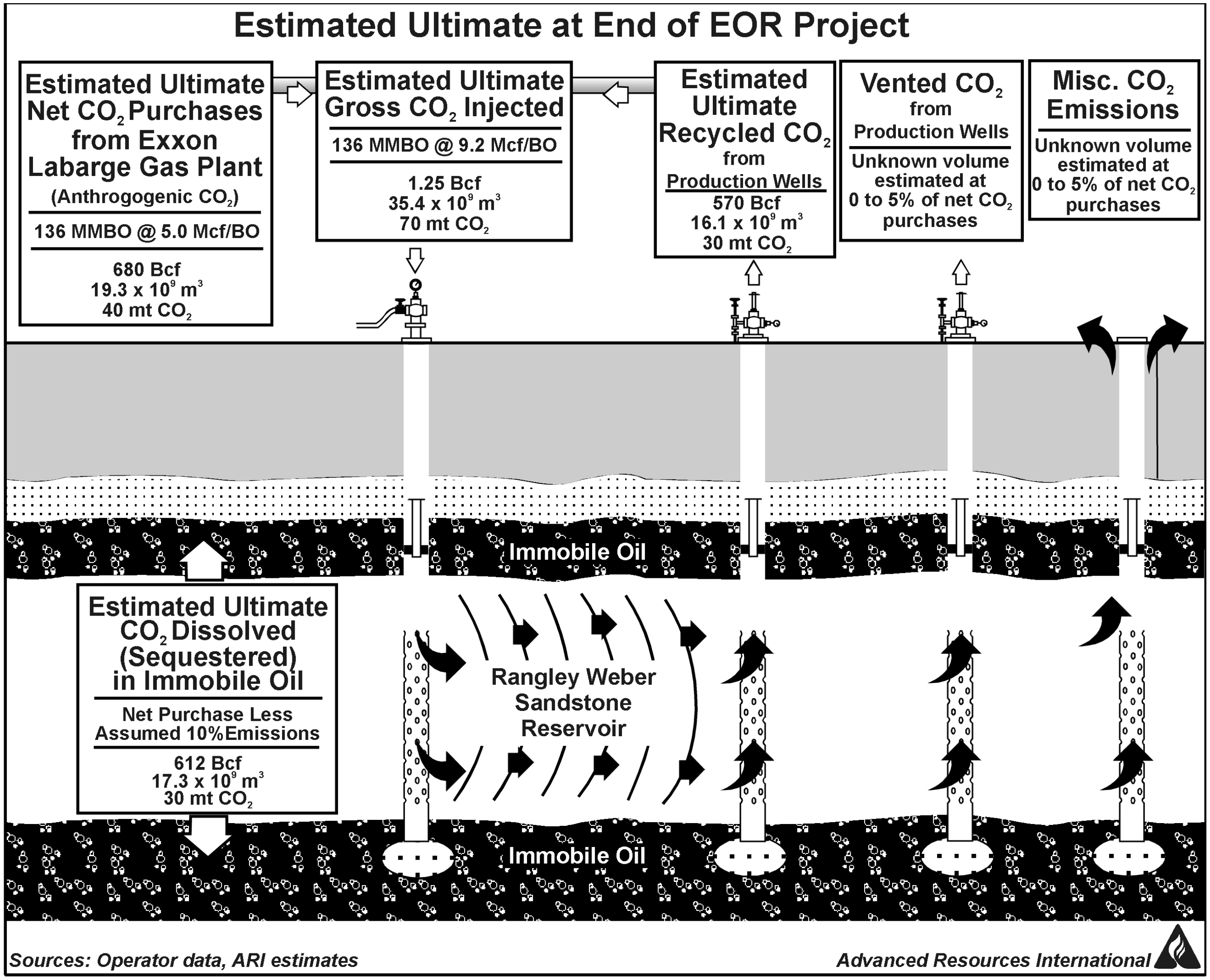


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Figure 4-3
Estimated Ultimate Volumes of CO_2 Injection, Recycling, and Inferred Sequestration at Chevron's Rangley Weber EOR Project, Colorado, U.S.A.

Sequestration "Rules of Thumb" Derived From EOR Projects

In addition to the Rangely Weber EOR project discussed in Chapter 4, our data base permitted a similar detailed level of analysis of CO_2 cycling and sequestration at 13 other EOR projects in the United States. We also collected substantial (but still incomplete) information on CO_2 injection from 18 additional EOR projects, not quite sufficient for estimating life-cycle sequestration for these projects. Together this data base is considered to be generally representative of average CO_2 sequestration performance at the 79 active worldwide CO_2-EOR projects, as well as the expanded universe of potential CO_2-EOR candidates in depleted oil fields.

Table 4-2 shows the estimated ultimate CO_2 purchases, EOR recovery, and calculated CO_2/EOR ratios for ten fields in the Permian basin. This data set encompasses a wide range of project size, from the largest (Altura Wasson Denver and Pennzoil SACROC) to much smaller projects with estimated ultimate EOR of less than 10 MMBO. The estimated ultimate enhanced oil recovery and CO_2 net purchases for these fields, which are forecasted by the operators based on past EOR performance and detailed reservoir simulation studies (just as for Rangely Weber), allowed us to compute the CO_2/EOR ratio for each project life. We then extrapolated this ratio to other comparable fields in the Permian basin. Ultimate sequestration of CO_2 at the ten Permian basin fields is estimated to total about 0.24 Gt (4.55 Tcf), with an ultimate net CO_2/EOR ratio of 5.6 Mcf/BO.

Table 4-2
CO_2/EOR Ratios and Sequestration at Selected EOR Projects in the Permian Basin, U.S.A.

Operator	Field	Estimated Ultimate EOR (MMBO)	% of OOIP	Est. Ult. Net CO_2/EOR (Mcf/BO)	Est. Ult. Net CO_2 Purchase (Bcf)	Estimated Ultimate CO_2 Sequestration (90% of Purchased) (Bcf)	(Gt)
Altura	Wasson Denver	348	16.6%	5.3	1,860	1,674	0.09
Pennzoil	SACROC[#]	169	8.0%	6.0	1,014	913	0.05
Chevron	N. Ward Estes	47	15.0%	7.1	334	300	0.02
Spirit Energy	Dollarhide	28	19.0%	7.0	194	175	0.01
Phillips	Vacuum East	30	11.5%	4.3	130	117	0.01
Texaco	Vacuum	33	15.6%	3.7	122	110	0.01
Texaco	Mabee	24	5.5%	5.0	120	108	0.01
Conoco	Ford Geraldine	13	13.1%	5.0	65	59	0.00
Enron	Two Freds	8	14.1%	8.0	64	58	0.00
Fasken	Hanford	10	60.9%	5.7	57	51	0.00
Total/Average 10 Fields		**710**	**10.9%**	**5.6**	**3,960**	**3,564**	**0.19**

[#]Anthropogenic CO_2 source was used for most of the project's life.
Note: numbers may not add due to rounding.

Table 4-3 shows CO_2 cycling and inferred sequestration at five additional fields in the Rocky Mountain and Mid-Continent regions of the United States. Rocky Mountain CO_2/EOR ratios average 4.9 Mcf/BO, slightly lower than the Permian basin average. Mid-Continent fields tend to use proportionally more CO_2, at least based on our smaller data set, and are more variable, at an average 7.1 Mcf/BO. Interestingly, all five fields in these regions for which we have data utilize anthropogenic sources for CO_2, including gas processing, fertilizer or ammonia production plants.

Table 4-3
CO_2/EOR Ratios and Sequestration at Selected EOR Projects in the Rocky Mountain and Mid-Continent Regions, U.S.A.

Operator	Field	Estimated Ultimate EOR (MMBO)	% of OOIP	Est. Ult. Net CO_2/EOR (Mcf/BO)	Est. Ult. Net CO_2 Purchase (Bcf)	Estimated Ultimate CO_2 Sequestration (90% of Purchased)	
						(Bcf)	(Gt)
Rocky Mountain Region							
Chevron	Rangely Weber*	136	7.2%	5.0	680	612	0.03
Amoco	Lost Soldier Tensleep*	24	9.9%	4.6	110	99	0.01
Total/Average 2 Fields		**160**	**7.6%**	**4.9**	**790**	**711**	**0.04**
Mid-Continent Region							
Henry Petr.	Sho-Vel-Tum#	10	4.8%	11.4	114	103	0.01
Stanberry Oil	Hansford@	2	16.0%	7.0	14	13	0.00
Occidental	NE Purdy#	17	7.5%	4.6	78	15	0.00
Total/Average 3 Fields		**29**	**7.2%**	**7.1**	**206**	**185**	**0.01**

Note: numbers may not add due to rounding.
* Anthropogenic CO_2 source (Exxon Labarge gas processing plant, Wyoming).
# Anthropogenic CO_2 source (Farmlands Corp. fertilizer plant in Enid, Oklahoma).
@ Anthropogenic CO_2 source (ammonia plant in Borger, Texas).

Economics of CO_2 Sequestration in EOR Projects

Economic analysis of sequestering CO_2 in EOR projects indicates that this technology compares favorably with other options that power generators have used, such as reforestation. Sequestration economics were modeled using actual project results (for active projects) and estimated reservoir characteristics (for future EOR projects). Appendix B presents the detailed methodology used in constructing a data base and economic model for estimating the CO_2 sequestration costs in EOR projects. This model was then used to generate sequestration/cost curves that help define the broad economics of CO_2 sequestration in depleted oil fields (Figure 4-4).

Our economic analysis represents full-cycle costs, comprising CO_2 capture, treatment, compression, transportation, and finally injection in an EOR project. Sales of enhanced oil recovery can offset some or all of these costs. The model can be readily improved and updated as new cost or resource data become available, or as sequestration technology advances. Power producers can use these cost curves to compare the sequestration capacity and costs of EOR with those of other alternative CO_2 reduction of sequestration technologies.

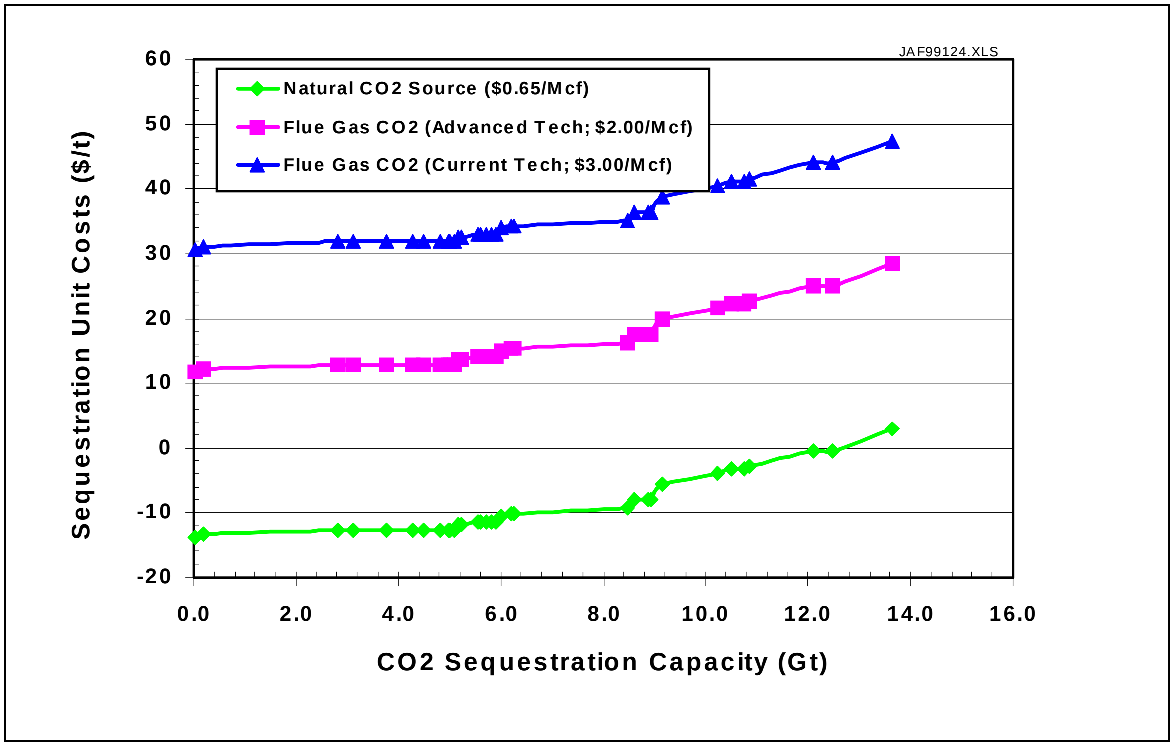


Figure 4-4
CO_2 Sequestration Capacity in U.S. EOR Projects ($18/B Oil Price)

Figure 4-4 shows that the total CO_2 sequestration capacity of EOR projects in the United States is estimated at about 14 gigatonnes (Gt). This capacity represents about 5.2 years of current CO_2 emissions by fossil fuel-fired power plants in the U.S. Based on current capture technology, which delivers CO_2 to the EOR field at a supply cost of around $3.00/Mcf, flue gas CO_2 can be sequestered in EOR projects at moderate full-cycle costs of approximately $30 to $45 per metric ton. If future advanced CO_2 capture technology can reduce supply costs to $2.00/Mcf, then full-cycle sequestration costs would fall to around $10 to $30/t. These costs do not consider the benefits of emission reduction credits, which would further lower the net cost of sequestration.

Current Status of Emission Reduction Credits and Trading Systems

Sequestration in CO_2-EOR projects is likely to expand markedly once a trading system is in place for valuing and exchanging CO_2 emission reduction credits. However, such a system is only now in the formative stage. Currently, Norway is the only country to directly tax CO_2 emissions, and to allow operators to avoid taxes by sequestering CO_2. However, even Norway does not yet allow for the most efficient scheme, whereby the CO_2 emitter can pay for its choice of the lowest-cost emission reduction or sequestration option, including overseas activities.

A number of experimental tradable credit systems are currently under development, although none are in routine commercial operation. Some of the more significant systems are discussed below:

- **Credit for Voluntary Reductions Act**: (U.S. Senate Bill S.547; formerly S.2617) This proposed legislation was introduced into the United States Senate on March 4, 1999. As currently envisioned, the proposal would provide businesses with legally binding credits for reducing their greenhouse gas emissions below a 1996-1998 emissions baseline. Such credits could then be sold or traded. Qualifying sequestration activities outside the U.S. would be limited to agricultural and nuclear power. This bill is still being shaped and changes are likely.
- **Greenhouse Gas Emission Reduction Trading** pilot (GERT) is a partnership of the Canadian federal government, several provinces and Canadian industry and other groups. Formed in 1998, GERT is designed to test the mechanics of a national trading system for greenhouse gas emissions in Canada. A similar but more local organization based in the Windsor-Quebec corridor of Canada (PERT) has overseen pilot trades on CO_2 emissions between member companies.
- **Trans Alta Corp.,** an Alberta-based energy company that is Canada's leading producer of independent power, currently has a standing offer to purchase offset CO_2 credits at approximately $2/tonne. This price is considerably less than the $53/tonne tax on CO_2 emissions currently in place in Norway, probably because the future value of such credits in the U.S. is still uncertain. Such a low value for CO_2 sequestration credits, if continued into the future, probably would not have a substantial impact on investment in CO_2-EOR projects.

5

CO_2 AND N_2 INJECTION FOR ENHANCED COALBED METHANE RECOVERY

Introduction

As discussed in Chapter 3, injecting gas (CO_2, N_2) into depleted oil fields to enhance oil recovery is a mature technology, with almost three decades of large-scale commercial application. A related but operationally different process is currently under development to improve recovery of coalbed methane from deep coal seams.

Coalbed methane (CBM) development has grown rapidly in the U.S. during the past decade, emerging as an important component of natural gas supply. In 1998, approximately 1.3 trillion cubic feet (Tcf) of CBM was produced, accounting for about 6% of total U.S. natural gas production (Figure 5-1). In some states, such as New Mexico and Alabama, CBM is the most important type of natural gas production.

The San Juan basin of southern Colorado and northern New Mexico currently dominates the industry, accounting for some 85% of CBM production (Map 5-1). Another 10% is produced in the Warrior basin of Alabama. The remaining production is from rapidly developing Rocky Mountain coal basins, such as the Uinta basin in Utah, the Raton basin in Colorado and New Mexico, and the Powder River basin in Wyoming. These latter three basins are expected to account for most of the growth in CBM production during the next decade.

Coalbed methane recovery requires significant electricity load, mainly related to three production procedures. First, large volumes of water are lifted from the production well using downhole submersible electric pumps. Second, coalbed methane is typically produced at low wellhead pressure (30 psi) and must be compressed to 1,000 psi or higher for transport and sale in a natural gas pipeline. Third, coalbed methane in the San Juan basin frequently contains high concentrations of CO_2 (about 10%), most of which must be removed prior to sales. Finally, because most CBM production takes place in Rocky Mountain Front Range areas with air pollution concerns and emissions restrictions, electric power has a distinct advantage over natural gas fuel for these energy intensive activities.

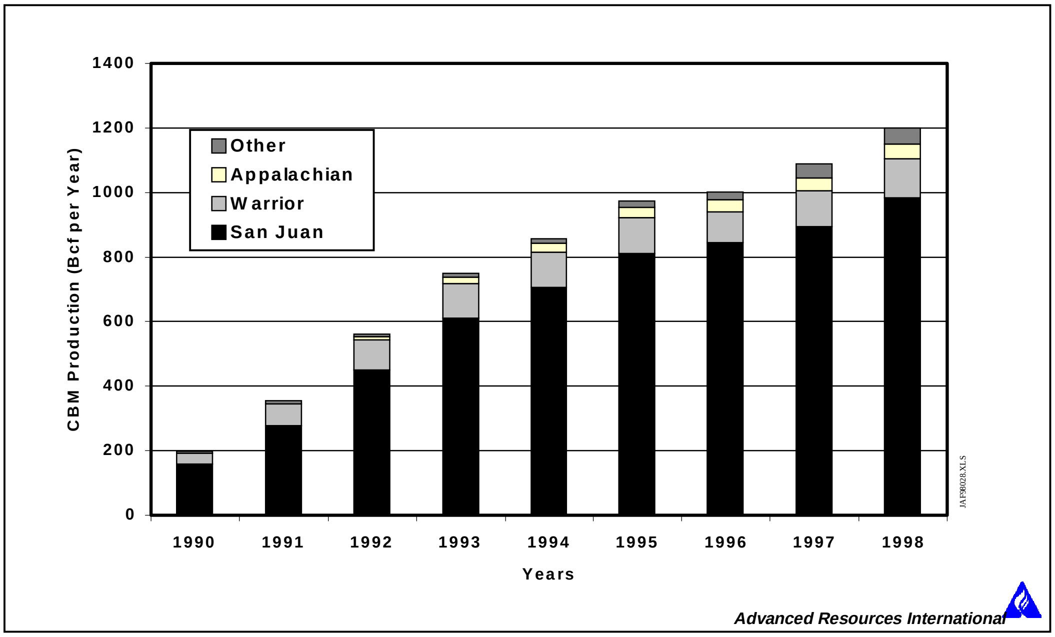
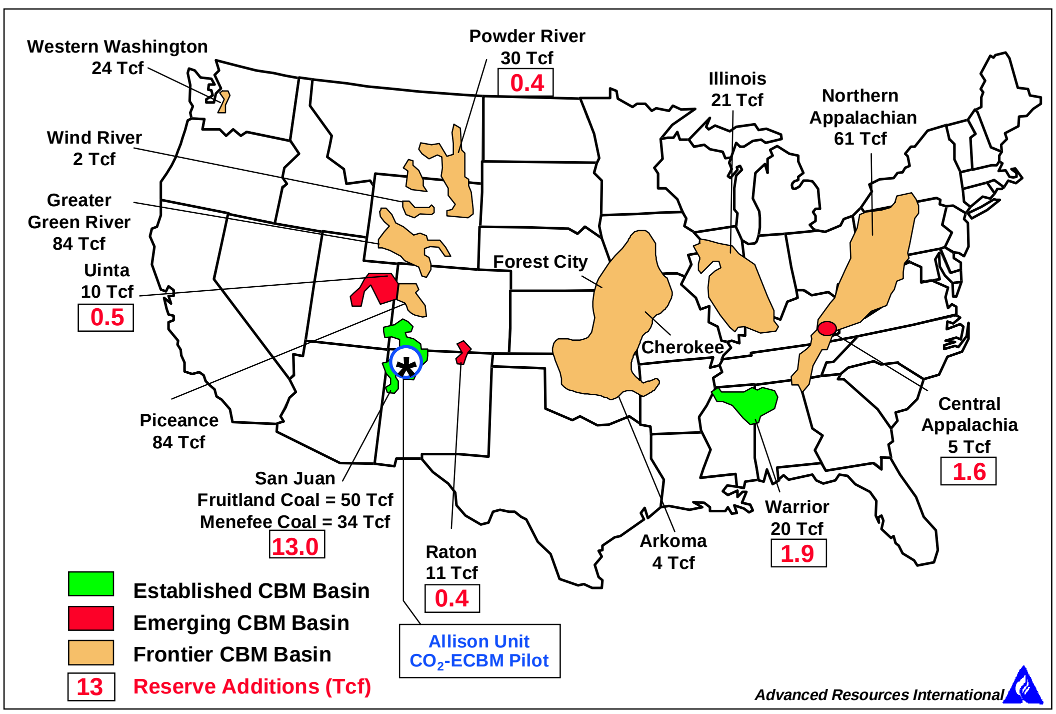


Figure 5-1
Coalbed Methane Production in the United States



Map 5-1
Coalbed Methane Development in the U.S. and Location of CO_2-ECBM Pilot

Enhanced CBM Recovery

Laboratory measurements show that injecting nitrogen or carbon dioxide can help to displace methane stored in a coal seam, improving coalbed methane (CBM) recovery. Theoretically, over 90% of the original gas-in-place can be recovered using ECBM. Two types of ECBM are undergoing testing: nitrogen and carbon dioxide injection.

Nitrogen ECBM works by lowering the partial pressure of methane, accelerating desorption and recovery of methane. Carbon dioxide ECBM operates through a distinctly different process: the coal preferentially adsorbs CO_2, actively displacing methane from the coal surface.

Nitrogen ECBM is thought to achieve more rapid methane recovery, but early breakthrough of N_2 makes processing the produced gas quite costly. CO_2-ECBM is thought to take a longer time to achieve enhanced methane recovery, but the CO_2 remains locked within the coal reservoir. This reduces gas processing costs and may qualify the project for potentially valuable CO_2 sequestration credits.

The first large pilot tests of CO_2- and N_2-enhanced coalbed methane recovery (ECBM) technology are currently underway in the northern San Juan basin of northern New Mexico. Initial testing indicates that these technologies are technically feasible and may be economically attractive. *ECBM technology represents a major opportunity for electric power growth. In addition, CO_2-ECBM may offer a low-cost disposal site for power plant flue gas CO_2.* At the current R&D phase of testing, power companies can play an useful role in helping to commercialize emerging ECBM technology.

CO_2 Injection for ECBM

Laboratory experiments show that carbon dioxide can displace methane adsorbed within coal. Using CO_2 flooding, over 90% of gas in place can theoretically be recovered from coal seams, compared with only 30 to 70% using conventional pressure-depletion production techniques. Furthermore, methane recovery can be accelerated, providing greater real (undiscounted) value for a given reserve. The technology for implementing and operating CO_2-ECBM recovery is based largely on demonstrated EOR methods, although further refinement still is needed. Sorption isotherm measurements in the laboratory indicate that two unit volumes of CO_2 are required to displace one unit volume of CH_4, although this empirical ratio may vary within an actual coal reservoir (probably higher due to out-of-zone migration). At least four patents have been issued for CO_2-ECBM, the first as early as 1977.

A typical field application of CO_2-ECBM technology is broadly similar to that of EOR operations (Figure 5-2). Carbon dioxide is transported to the CBM field and injected into the coal seam reservoir through dedicated injection wells. At the production well, natural gas and formation water is lifted to the surface using electric pumps. Eventually, CO_2 breakthrough takes place. The produced CO_2 then is removed from produced gas, dehydrated, and then re-injected in the injection well.

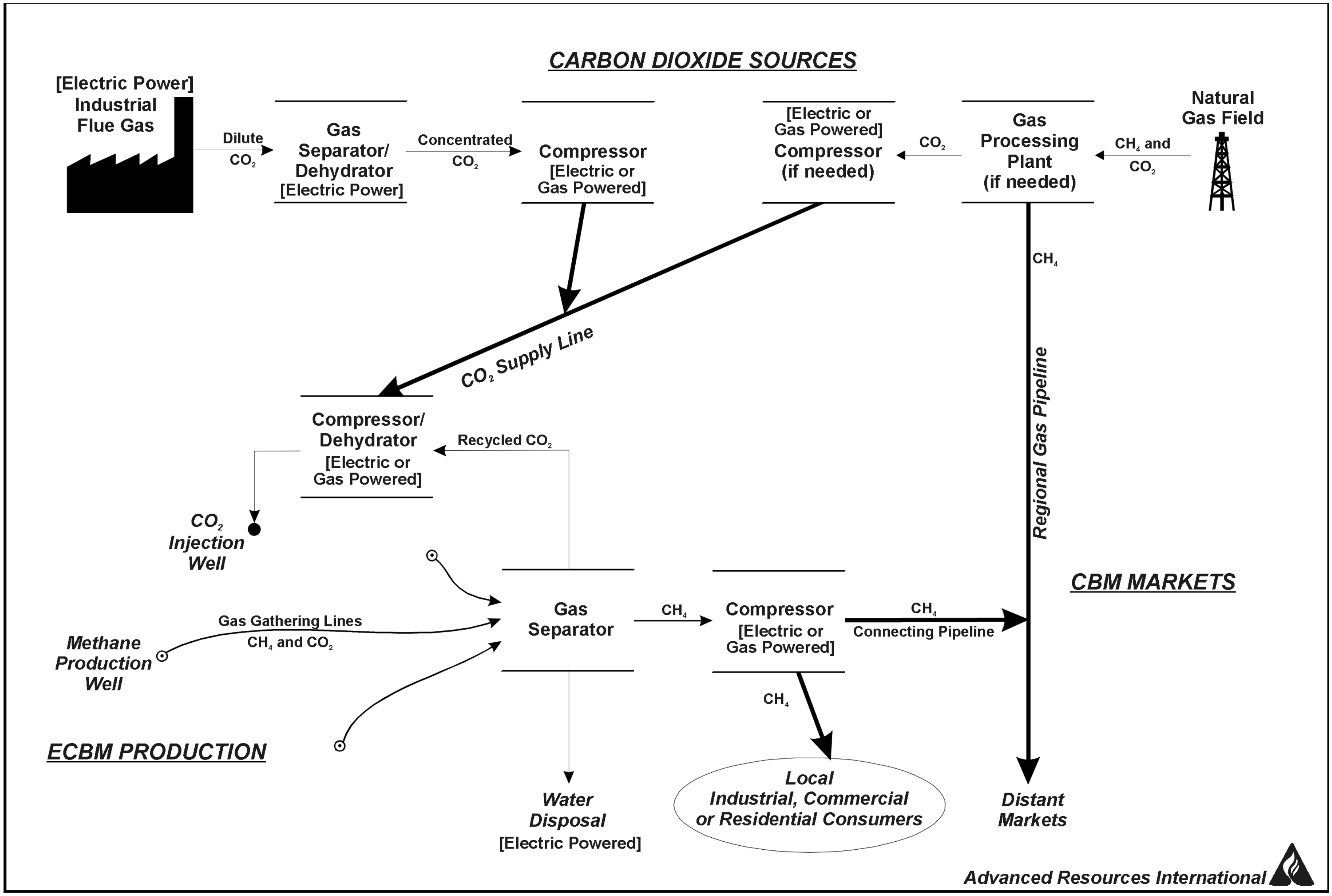


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Figure 5-2
Components of a CO_2-EOR Recovery System

A variety of CO_2 sources, both natural and anthropogenic, may be used within CO_2-ECBM recovery operations. Naturally occurring, high-pressure CO_2 produced from underground reservoirs is the lowest cost source, provided that the transport distance to the CBM field is not excessive. In addition to natural CO_2, two types of anthropogenic CO_2 are readily available: waste CO_2 from gas processing plants and flue gas from fossil fuel power plants. Just as with EOR, in the future, a system of tradable CO_2 emissions credits could develop that would dramatically reduce the cost of CO_2 purchase for the CBM operator.

Natural gas processing plants, which remove CO_2 from natural gas production for pipeline requirements, could provide a moderate-cost anthropogenic source of CO_2. In the San Juan basin, about 150 MMcfd of CO_2 is separated from coalbed methane production and vented to the atmosphere. This CO_2 could be collected, compressed and sequestered in ECBM operations. Indeed, Burlington Resources' original operating permit for the Allison Unit envisioned utilizing waste CO_2 from gas plants.

The San Juan basin provides an ideal location for testing CO_2-ECBM recovery. The basin has ready access to natural gas sales and CO_2 supply pipelines. Burlington Resources and other operators in the basin are pioneers in developing and applying CBM technology. Geologic and reservoir conditions influencing production from coal seams are relatively well understood in the basin, following years of study by CBM operators, the Gas Research Institute, and the U.S. Department of Energy. Finally, CBM services and equipment are provided at low cost through an efficient and competitive oilfield supply industry. All of these factors combine to make the San Juan basin an ideal location for initial testing of ECBM and CO_2 sequestration technology.

Burlington Resources CO_2-ECBM Pilot, San Juan Basin, New Mexico

Since 1996 Burlington Resources, a major U.S. independent that is the largest producer of coalbed methane, has conducted the world's first (and to date only) commercial pilot application of CO_2 injection (Stevens et al., 1998). Burlington's pilot is located within the Allison production unit of the northern San Juan basin, in north-central New Mexico (Map 5-2). The San Juan basin is by far the most successful CBM development in the world, with per-well gas production averaging over 800 Mcfd.

The Allison Unit pilot comprises four CO_2 injection wells and nine CH_4 production wells (Map 5-3). The production wells (320-acre spacing) were produced from the Cretaceous Fruitland Formation coal seams using conventional pressure-depletion methods for a period of about five years prior to injection of CO_2. About half of the production wells were cavitated, the remainder were naturally completed. The production wells had dewatered and reached near-peak gas production by 1995, averaging about 1 MMcfd, but with considerable variation. Burlington then drilled four injection wells on 320-acre spacing and initiated CO_2 injection starting in May 1995.

The injection wells were also completed in the Fruitland coal seams, but were not hydraulically stimulated to reduce the risk of CO_2 leakage outside of the targeted coal reservoirs (Figure 5-3). CO_2 injection has proceeded fairly continuously at about 750 Mcfd per well. The four injection wells handle some 3 MMcfd of naturally occurring CO_2 produced at McElmo Dome field in southwestern Colorado. A pipeline transports a total of about 900 MMcfd of CO_2 from McElmo Dome southeastwards across the San Juan to the Permian basin of West Texas, where it is injected in enhanced oil recovery operations. A short connector links the Allison Unit to this CO_2 pipeline. Line pressure is reduced from 2,000 psi in the Shell operated pipeline to about 1,100 psi for injection at the Allison Unit pilot, safely below the fracture gradient. A glycol heater raises CO_2 temperature from supercritical to reservoir levels of about 49° C.

Water production increased markedly at the start of CO_2 injection, demonstrating improved sweep of bypassed reservoir areas that should lead to higher ultimate gas recovery with continued operation. Higher water production also translates directly to higher electricity consumption. Another positive indication that sequestration is taking place is that the CO_2 content of produced gas has not changed significantly throughout the injection period, despite nearly 3 Bcf of cumulative CO_2 injection. Some breakthrough is likely to occur within several years, however. In a long-term ECBM project, CO_2 could be recycled and re-injected, just as takes place routinely in enhanced oil recovery projects.

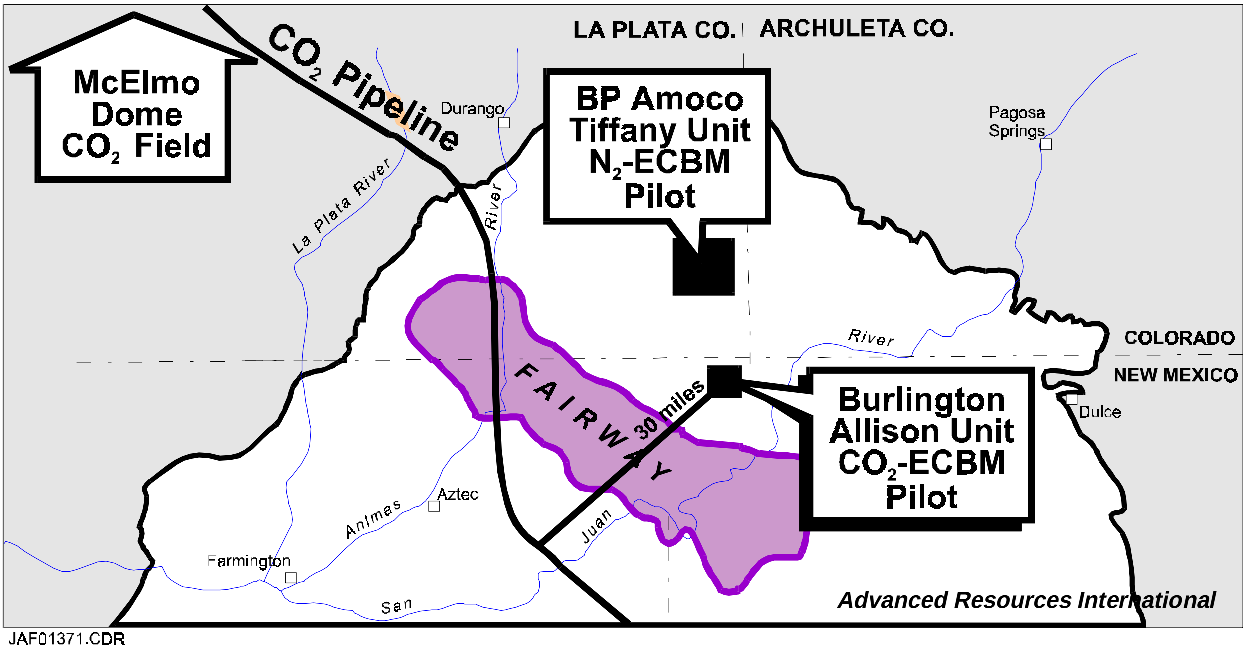
N_2 Injection for ECBM

Nitrogen injection for enhanced coalbed methane recovery is actually further along in the demonstration process compared with carbon dioxide injection, but less information is publicly available. Amoco (now BP Amoco) is the only company to have conducted long-term testing of N_2-ECBM in the field. Their newest and largest ECBM pilot in southern Colorado is just now providing results that allow this new technology to be evaluated.

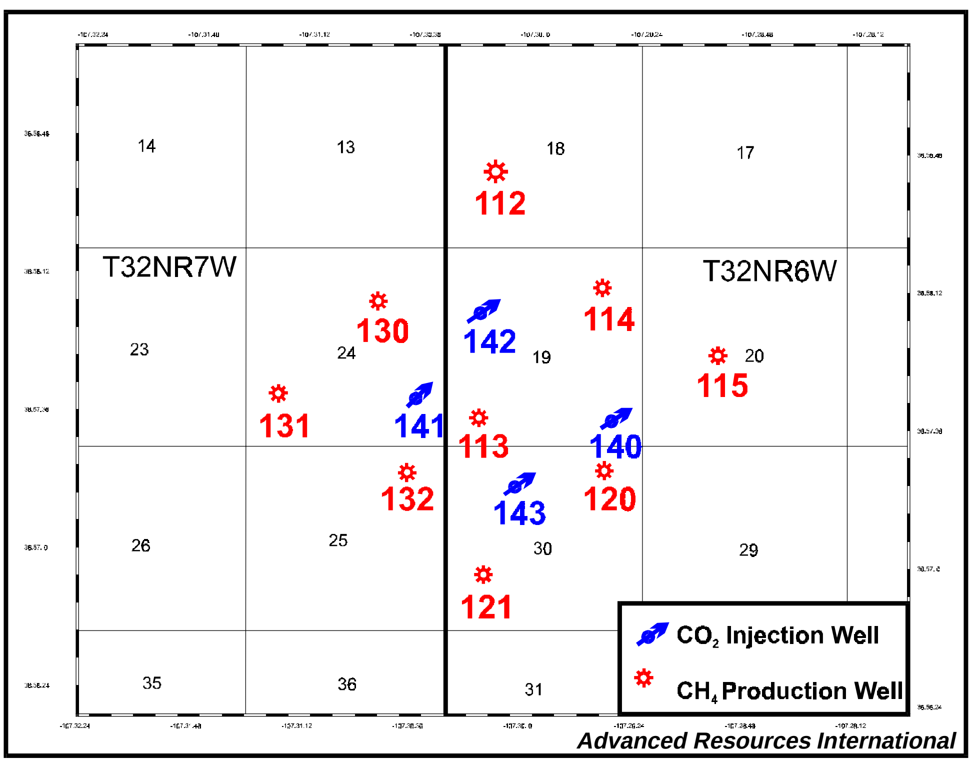
During the mid-1990's, BP Amoco performed several small N_2-ECBM pilots in the San Juan basin, at the Simon 15U-2 pilot (1 injector, 5 producers) and at the 28-7 Unit pilot (5 injectors, 7 producers; Stevens et al., 1996). Results from these tests reportedly were encouraging, but very little hard data has been released. Starting February 1998, BP Amoco initiated a much larger pilot at its Tiffany Unit, located in the northeastern San Juan basin (Map 5-2).

The Tiffany area is a low-permeability portion of the San Juan basin. Recovery of initial gas in place is relatively low in this region, less than 5% of OGIP compared with over 50% recovery of OGIP in the more permeable "Fairway" portion of the San Juan. The large volume of gas resource remaining in the reservoir after normal production operations makes Tiffany an attractive candidate for ECBM.

The Tiffany project involves about 12 N_2 injection wells and 34 production wells. Currently, BP Amoco is injecting an average of 28 MMcfd of nitrogen, which is sourced from the atmosphere using cryogenic separators. Amoco's previous 28-7 Unit pilot employed a skid-mounted membrane separation system manufactured by Niject. About 50 MMcfd of air is processed to provide the 28-30 MMcfd of pure nitrogen for injection into the Fruitland coal reservoir at a depth of about 3,000 feet. The nitrogen injectant is then boosted from atmospheric pressure to 2100 psi in three stages before it is injected.



Map 5-2
Location of ECBM Pilots, San Juan Basin, New Mexico



Map 5-3
Allison Unit CO_2-ECBM Pilot, San Juan Basin

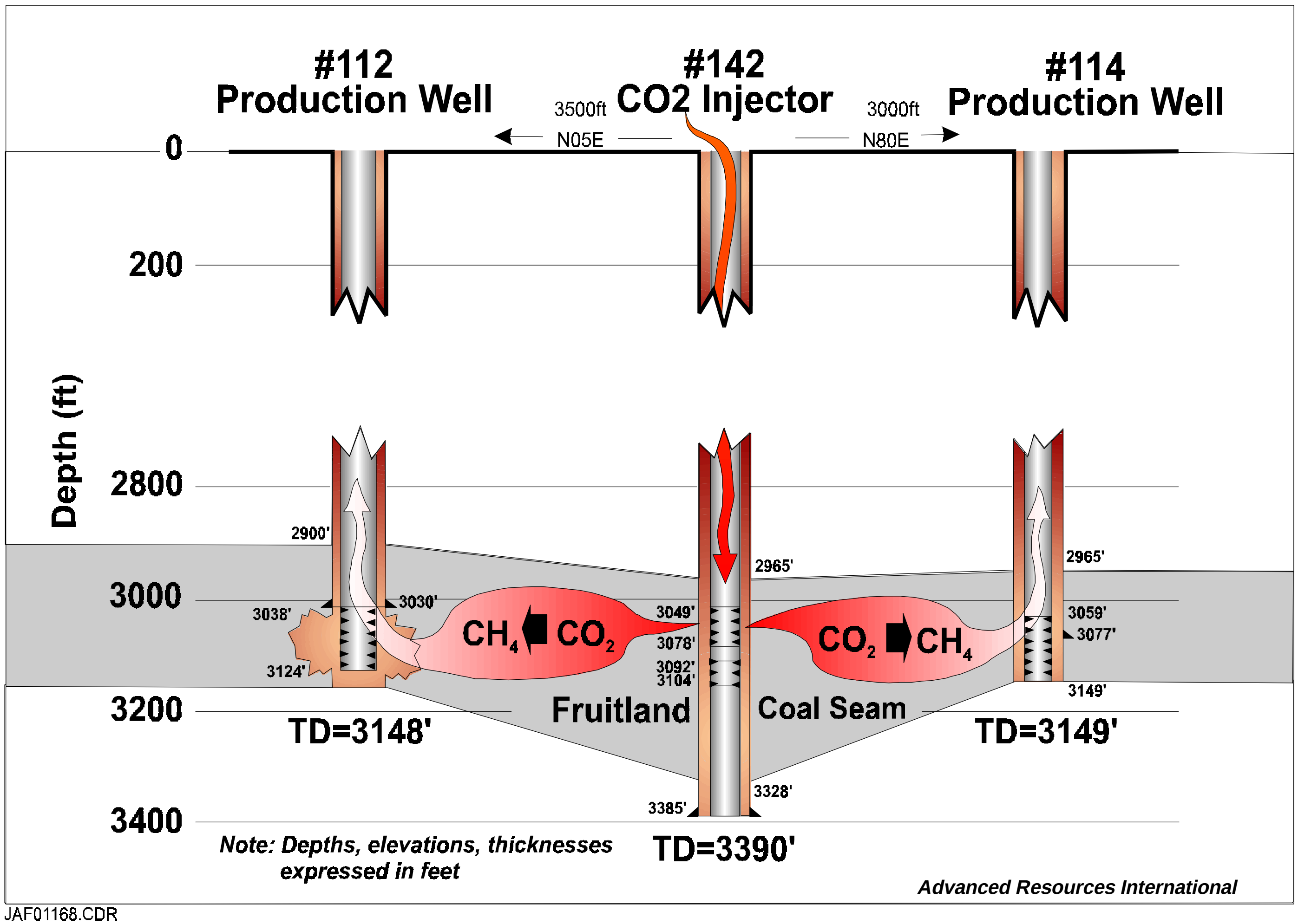


Figure 5-3
Cross-Sectional View of the Allison Unit

The Tiffany project employs 2 x 2,000 hp electric compressors, which were selected in the natural gas basin reportedly because of emissions restrictions. Current electricity costs for the Tiffany ECBM project amount to about $100,000 per month. Other costs for dehydration, CO_2 removal, etc. are confidential. The total capital and operating costs of nitrogen processing and injection are approximately $0.60/Mcf, which makes the ECBM project marginally economic at current natural gas wellhead prices ($2.00/Mcf). BP Amoco is continuing to operate this pilot and evaluate its effectiveness.

Outlook for ECBM Development and Power Industry Opportunities

Although N_2- and CO_2-ECBM/sequestration technology is still under development, it appears to be one of the most significant recent developments in enhanced recovery of hydrocarbons to take place in several decades. If this technology penetrates on a large scale, there could be two major opportunities for power providers.

First, the current water lifting requirements of approximately 195.3 MMbwpd in coalbed methane fields would be expected to increase. This is because ECBM increases the efficiency of reservoir sweep and concomitant water recovery from coal reservoirs. Essentially all of this water lift is provided by 10 HP rated electrically driven pumps. The increase in power demand will depend on the penetration rate of this technology and thus is difficult to predict, but it could reach 10% per year or higher. In addition, ECBM technology may make new areas economic, particularly gas undersaturated areas such as the Greater Green River basin (Wyoming), which is characterized by particularly high water production rates. This increased lifting could further increase power demand.

Second, the injection of CO_2 for ECBM also represents a technically and economically attractive disposal site for this greenhouse gas. The most favorable areas, such as the San Juan basin, may be economically profitable based on CO_2 supply costs of about $0.50/Mcf. Emissions credits may enable ECBM operators to dispose of power plant CO_2 emissions cost effectively. Many coal-fired power plants are located close to or within coal fields. Given the unique storage characteristics of coal, which adsorbs CO_2 onto its surface under pressure, there should be little risk of leakage from the coal reservoir (barring mining of the coal).

The U.S. Department of Energy (USDOE) is expected to provide co-funding to at least one additional CO_2-ECBM/Sequestration pilot during the next year. In addition, individual power companies are considering participating in or partially funding CO_2-ECBM/Sequestration demonstrations in the U.S. and other countries. The author of the current study (ARI) has contracted with BP Amoco to apply for USDOE funding to test this technology in the San Juan basin.

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6
THERMAL ENHANCED OIL RECOVERY TECHNOLOGY

Introduction

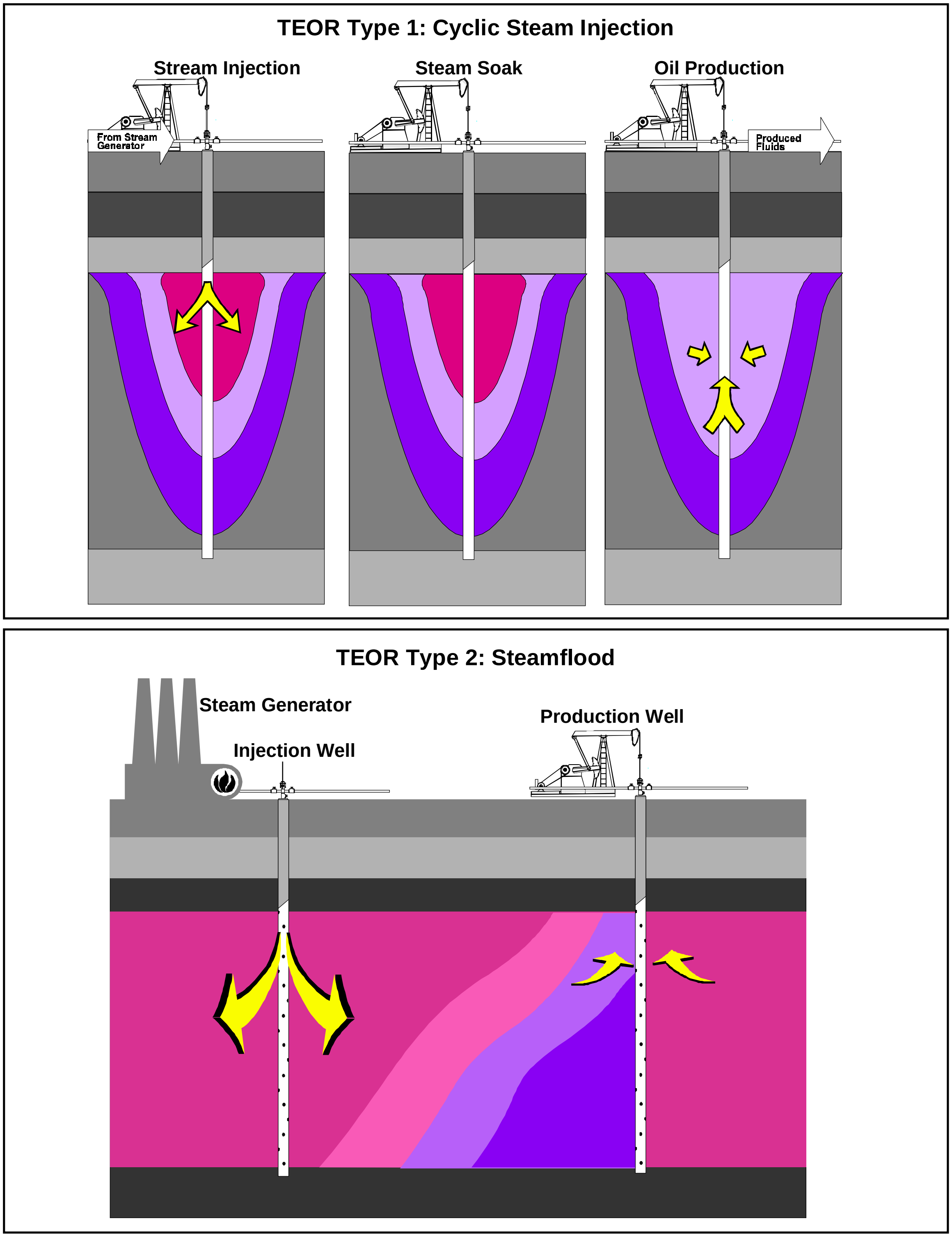
Enhanced oil recovery (EOR) using thermal — particularly steamflood — technology is the most widely employed EOR method in the United States and is an important source of domestic crude oil supply. Thermal EOR (TEOR) accounts for about two-thirds of total EOR production in the Lower-48 United States, although gas EOR (primarily CO_2 flooding) production is growing more rapidly. TEOR technology is expected to continue to be the most important EOR production process in the U.S. during the next two decades, after which CO_2-EOR may well overtake TEOR.

Despite the dominance of TEOR production, the electric power demand for TEOR operations is actually significantly less than for gas EOR methods. With an energy intensity of less than 0.5 horsepower/barrel of oil per day (HP/BOPD) capacity, TEOR requires an estimated total power capacity of nearly 200,000 HP. In contrast, CO_2- and other gas-injection EOR operations are more energy intensive at over 4 HP/BOPD, currently requiring an estimated total 1.25 million HP to produce and process 315,000 BOPD. In addition, gas EOR power growth is expected to be much faster than for thermal EOR. Finally, many thermal EOR fields produce steam along with electricity in centralized facilities. Most TEOR fields not only generate enough power for their own internal needs, but are also able to export significant power to the grid.

Although the energy intensity of TEOR operations is low and overall TEOR production is declining, nevertheless, there will be opportunities for demand growth in particular California heavy oil fields. However, these are likely to be smaller than for gas EOR. Consequently, this section is not as extensive as for gas EOR methods.

Two main methods are used for thermal EOR: cyclic steam and steamflood (Figure 6-1). Both work on the dual principles that heat can increase the viscosity of heavy oil, improving its mobility and recovery, while water injection can maintain reservoir pressure and improve sweep.

The cyclic steam method, which was developed first and commercially implemented in the 1960’s, uses alternate periods of steam injection followed by oil production. This method uses less capital, because no dedicated steam injection well is required, although the production well casing may need upgrading to handle steam injection. However, cyclic steam injection is a less efficient oil recovery method than steamflood because the steam penetrates only a limited radius around the production well. Nevertheless, this method still is fairly common in many California heavy oil fields, and is particularly important at Midway-Sunset, Cymric, Wilmington and other fields.



Advanced Resources International

Figure 6-1
Cyclic vs. Steamflood Thermal EOR Processes

Steamflood technology, introduced in the 1970’s, has largely replaced the cyclic steam method. Steamfloods employ separate steam injection and oil production wells. Steam is injected into the poorly swept portion of the reservoir between the production wells. As the steam penetrates throughout the permeable reaches of the reservoir, it facilitates recovery of a much higher fraction of original oil in place compared with primary/secondary recovery and with cyclic steam. However, capital costs are much higher than for cyclic steam, because dedicated injection wells and additional surface facilities are required. The volume of steam injected also tends to be much greater. Steamflood is the dominant method used at Kern River, South Belridge, Coalinga, San Ardo, Lost Hills and many other heavy oil fields in California.

Currently, worldwide heavy oil production from thermal EOR methods totals an estimated 1.3 million b/d, the bulk of which comes from California, Sumatra, and the Lake Maracaibo region of Venezuela. Canada also has vast heavy oil and oil sands resources, as well as substantial thermal EOR production and technology development, such as bitumen and heavy crude upgrading (e.g., Newell, 1999). Although highly energy intensive, upgrading is not likely to be a growth area for California heavy crude, because demand for heavy oil is already adequate. The primary users of heavy crude in California include specially designed refineries and the local construction industry.

California TEOR Production

California currently has nearly 20,000 wells producing heavy oil within thermal enhanced oil recovery (TEOR) projects, producing an average of 393,000 BOPD of incremental oil in 1998 (Table 6-1). This is equivalent to about 7% of total U.S. crude oil production. The heavy oilfields of central California comprise the world’s largest steamflood development, and account for more than 99% of TEOR production in the U.S. Geologic conditions in many California heavy oil fields are ideal for steamflooding: shallow depth (<2,000 feet), good lateral continuity and permeability, low gravity (average 14°API), and adequate vertical isolation of the reservoir.

Steamflood operations are underway in 18 individual oil fields in California, although just three fields (Kern River, Midway-Sunset, and South Belridge) account for 80% of total TEOR production. TEOR operations are concentrated in Kern County, within California’s San Joaquin Valley (Map 6-1). The other projects are dispersed throughout southern California, in Los Angeles, Monterey, San Luis Obispo, and Fresno Counties.

Production declined about 6% in 1998 compared with 1997 levels, in response to sharp declines in the price of Kern River heavy (13°API) crude oil. Low oil prices during late 1998 and early 1999 were exacerbated by relatively high natural gas fuel prices, which remained historically high relative to oil. Sharp production declines at South Belridge and Cymric fields, more than offset production gains at low-cost Midway-Sunset and Kern River fields. A forecast of future TEOR production is presented in Chapter 6.

Table 6-1
Thermal EOR Production in California, 1997 vs. 1998

TEOR Field	1997 TEOR Production (BOPD)	1998 TEOR Production (BOPD)
Midway-Sunset	115,194	142,304
Kern River	116,911	127,084
South Belridge	86,405	44,310
Cymric	35,912	20,661
Coalinga	22,200	20,479
San Ardo	12,063	11,657
Lost Hills	8,837	8,873
McKittrick	5,948	4,742
Placerita	3,307	3,370
Kern Front	3,105	2,963
Wilmington	3,220	2,635
North Belridge	1,435	1,367
Arroyo Grande	1,483	1,356
Other	1,972	764
Total	**419,112**	**392,565**

Source: California Division of Oil, Gas, and Geothermal Resources

Just as with CO_2-EOR, thermal EOR production is dominated by Major integrated oil companies. Four companies (Aera {a joint venture between Shell and Mobil}, Texaco, Chevron, and Arco) accounted for the overwhelming majority of overall TEOR production during 1998 (Table 6-2). Furthermore, this concentration has increased significantly in recent years, as Sante Fe Energy, Unocal, and other firms chose to divest their heavy oil properties in California. These firms cited marginal profitability and environmental restrictions as the principal reasons for their exit from California heavy oil production.

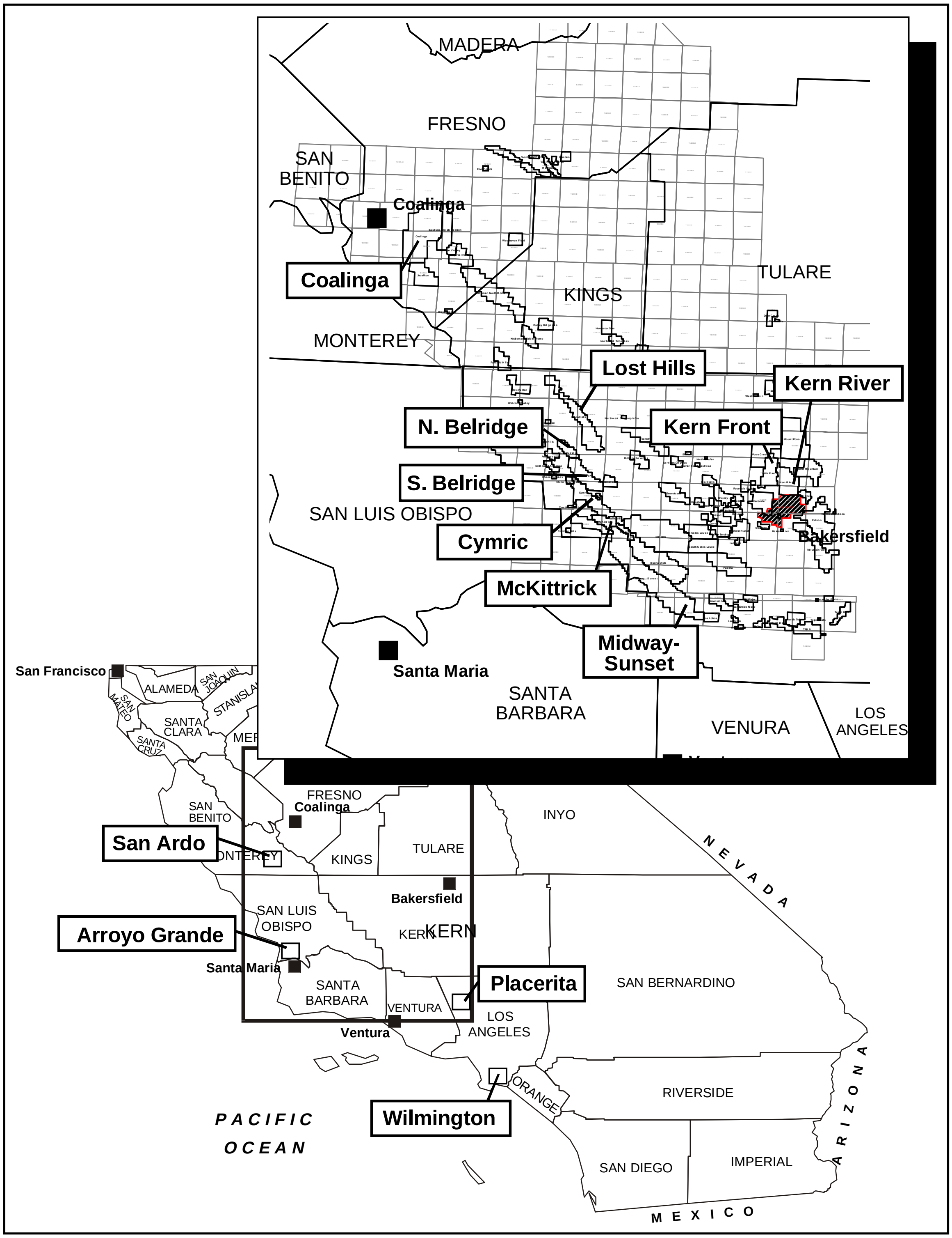
Table 6-2
TEOR Production Is Dominated by Four Major Oil Companies

Rank	Operator	1998 TEOR Production (BOPD)
1	Aera (Shell/Mobil)	170,840
2	Texaco	150,965
3	Chevron	52,010
4	Arco	38,940
	Others	33,215
	Total	**392,565***

* EOR production reported by operators is higher than California DOGGR total EOR Production.

During the past three decades, TEOR production in California has evolved through three major phases of development, punctuated by major technological developments and oil price fluctuations. Historical production is presented in Figure 6-2, while the three major development phases are summarized as follows:

- **1964-1977** — The introduction of cyclic steam drive technology enabled thermal EOR production to climb steadily to approximately 245,000 BOPD in 1977. Although oil prices rose sharply after 1973, price controls restrained development of relatively high-cost TEOR resources during this period.
- **1978-1985** — Rising oil prices, the release of domestic EOR production from price controls, and the expanded application of steamflood technology vis-a-vis cyclic steam boosted TEOR production dramatically to approximately 475,000 BOPD in 1985.
- **1986-Present** — Falling oil prices, including a drop in Kern River crude to $6/bbl in 1986, severely curtailed the growth of TEOR, although the momentum of past investment caused production to peak at 510,000 BOPD in 1987. The production decline has been moderated by corporate restructuring and significant reduction in operating costs, and by continued technological advances, notably improved reservoir characterization. (A one-time accounting revision in 1995 reduced TEOR production at Midway-Sunset by 50,000 BOPD.)



Map 6-1
Major Thermal EOR Projects in California

California TEOR Operations

California oilfields are shallow, averaging 1,500 feet deep, and produce heavy oil of typically 14-degree API gravity (Table 6-3). Well spacing varies from 1 to 10 acres per producing well, averaging 1.5 acres. Approximately 20,000 production wells and 16,000 steam injection wells are currently in operation. Operating ratios of injected steam to enhanced oil recovery – the most critical technical/economic variable – vary widely, from an efficient 2.47 barrels steam/barrels oil (BS/BO) at Kern River field, to a less optimal 8.43 BS/BO at Kern Front field. This variation reflects the diverse reservoir architecture of these fields, as well as the different stages of operational maturity of each steamflood.

- **Steam Generation:** Steam and/or hot water is generated using boilers or as a by-product of cogeneration. Natural gas currently accounts for over 90% of the fuel used in steam generation, and for environmental reasons is certain to be selected in all future steam generation facilities. Fuel oil and coal-fired boilers, grandfathered under current regulations, are few and small capacity. Electricity is not used to produce or transport steam because of the relatively high costs.
- **Steam Distribution and Injection:** Steam and/or hot water are distributed by insulated surface distribution manifolds to injection wells. This part of the operation relies on electric pumps but is not particularly energy intensive.
- **Production Operations:** Producing wells recover oil, water, and small volumes of gas. The gas/oil ratio in California heavy oil fields is extremely low. Consequently, the demand for gas processing and compression is not significant. Produced fluids are then transported to central processing facilities. Lifting fluids is by far the major consumer of power in thermal EOR projects.
- **Water Treatment:** Most of the produced water is re-injected back into the oil reservoir to maintain pressure and improve recovery. The total dissolved solids of TEOR produced water varies greatly, from very low (1,000 ppm) at Kern River in the eastern San Joaqin Valley to near seawater (30,000 ppm) at McKittrick in the western San Joaquin Valley. Produced water generally must be treated prior to reuse to remove scale-forming calcium and magnesium. However, harder-to-treat constituents – such as sodium and chloride – do not require treatment. Ion exchange is the most common treatment method for scale removal and is relatively inexpensive ($0.01/barrel water). This process generates moderate power demand for pumping.

Case studies of selected thermal EOR projects in California are presented in Appendix C.

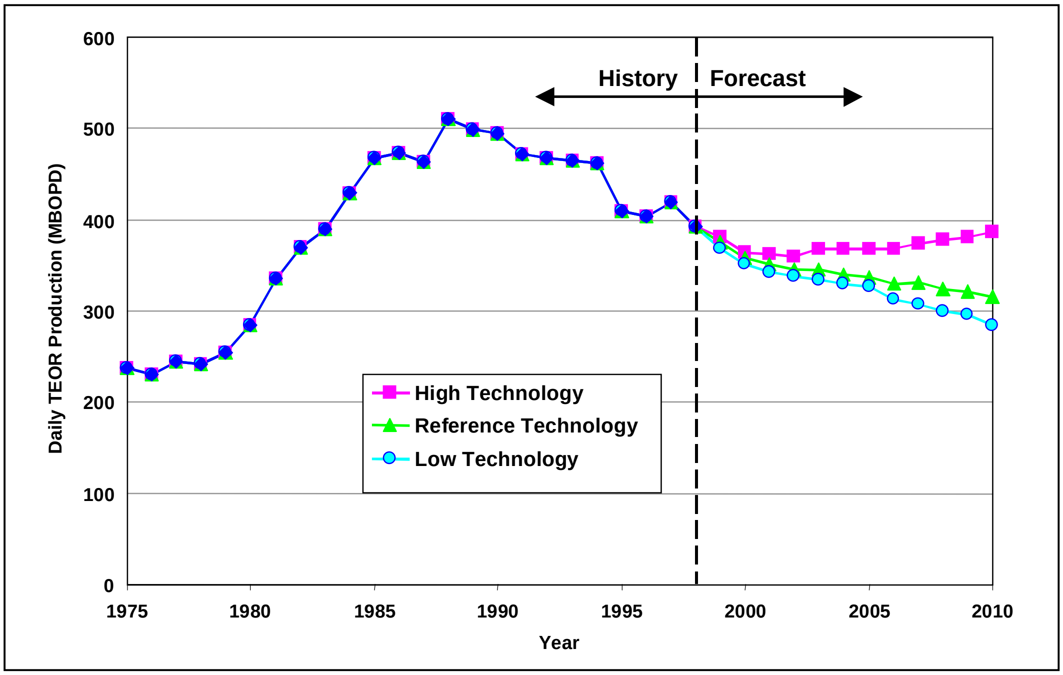


Figure 6-2
Historical and Forecasted TEOR Production Low Oil Price Scenario, Varying Technology

Table 6-3
Reservoir Properties and Steam/Oil Ratio in California TEOR Fields

Field	Oil Gravity (API Deg)	Reservoir Depth (feet)	Pattern Spacing (acres)	Est TEOR Producing Wells	Steam Injection Wells	Steam/Oil Ratio (BS/BO)
Midway-Sunset	13	1700	1.0	6,450	5,448	4.19
Kern River	13	900	1.0	6,323	7,073	3.20
South Belridge	13	1100	2.0	3,996	1,115	3.66
Coalinga	15	2000	2.0	1,252	625	3.88
Cymric	13	1000	2.0	645	742	2.47
Lost Hills	20	1000	2.0	564	239	3.82
San Ardo	12	2200	7.5	280	118	4.56
Kern Front	14	2000	3.0	253	106	8.43
Mt. Poso	13	1800	10.0	128	32	3.57
Placerita	13	1500	1.5	87	134	6.52
Weighted Average (by Wells)	**13.9**	**1520**	**1.5**			**3.68**
Total (10 Fields)				**19,978**	**15,632**	

Model for Forecasting TEOR Production

The thoroughly characterized heavy oil resource base, extensive data availability, vast scale of continuing investment in new wells and facilities, and diverse strategies of operating companies active in the play are factors which combine to make TEOR operations in California amenable to simulation using an economic forecasting model.

ARI recently constructed a sophisticated engineering-based economic model of California thermal EOR production for the U.S. Department of Energy (Stevens and Kuuskraa, 1997). The model is called the Thermal EOR Economic Model ("TEEM"). The TEEM model constitutes a portion of USDOE's more comprehensive Oil and Gas Supply Model (OGSM), which simulates the entire United States petroleum industry.

To a considerable extent, California heavy oil fields have already been largely identified and characterized. New TEOR development generally requires only demonstration pilot fields with little or no exploration risk or costs. Thus, it is feasible for the TEEM economic model to be field-based and grounded on actual engineering and economic data from existing fields. The model is a data-intensive representation of actual production economics in steamflood operations (Figures 6-3 and 6-4). As such, the model is fundamentally different from statistical, probability-based models that typically are used to project future light oil exploration and production.

The TEEM model consists of:

Proved TEOR Reserves Submodule: Proved reserves are modeled separately because extensive data are generally available on production rates and costs for existing wells compared with less-documented undeveloped areas, enabling future production to be predicted with greater accuracy. Of particular value, the state and certain counties of California annually report basic data on well productivity, new well completions, oil gravity, injected steam volumes and other key variables.

Operating costs for steamflood operations are reported annually by the Kern County, the largest center for TEOR operations in the state. These costs serve as key inputs for evaluating the economics of proved reserves. In addition, considerable additional production and cost data were obtained from individual steamflood operators and used to refine the public data.

Proved TEOR reserves are not publicly reported, but may be estimated from total reserves based on the proportion of TEOR production to total oil production by field. As shown in Table 6-4, the 10 largest TEOR fields in California accounted for the vast majority (98%) of total EOR production during 1997. Proved TEOR reserves are estimated to total 1.3 BBO, and are heavily concentrated in just three fields (Kern River, Midway-Sunset, and South Belridge), which together account for about three-quarters of total U.S. TEOR production and estimated proved reserves. The reserve/production ratio has declined over the past decade to the current efficient 7.4, but still varies considerably by field.

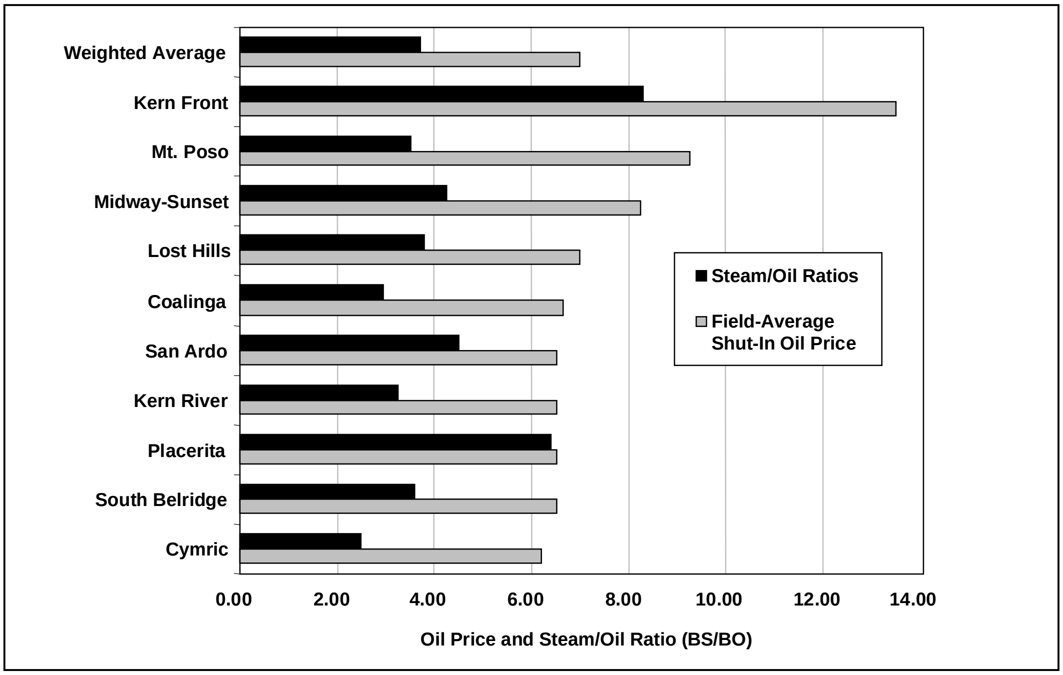


Figure 6-3
Shut-In Price and Steam/Oil Ratios, California Thermal EOR

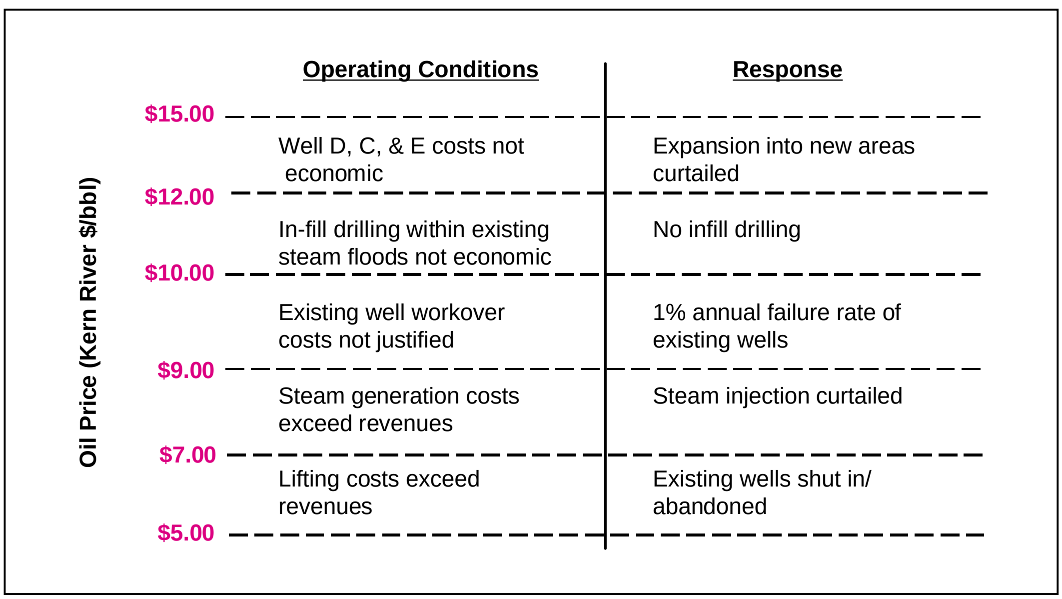


Figure 6-4
Conceptual Operator Response to Wellhead Prices in California TEOR Fields

Table 6-4
Estimated California TEOR Production and Reserves

Heavy Oil Field	1997 Crude Oil Production (MBOPD)			1996 Crude Oil Reserves (MMBO)		
	Total Oil Production	TEOR Production	% TEOR	Total Oil Reserves	TEOR Reserves	R/P Ratio
Kern River	133.7	113.6	85%	377.7	321.0	7.7
Midway-Sunset	166.3	113.1	68%	393.4	267.5	6.5
South Belridge	117.3	83.3	71%	315.1	223.7	7.4
Cymric	37.8	36.7	97%	85.0	82.5	6.2
Coalinga	26.4	22.2	84%	66.8	56.1	6.9
Lost Hills	31.5	12.3	39%	58.7	22.9	5.1
San Ardo	12.7	11.9	94%	87.5	82.3	18.9
Placerita	3.3	3.2	98%	12.8	12.5	10.6
Mt. Poso	3.1	3.0	98%	31.6	31.0	27.9
Kern Front	5.8	2.8	49%	25.7	12.6	12.1
Total (10 Fields)	**538**	**402**	**75%**	**1,454**	**1,087**	**7.4**
Total California TEOR		**410**			**1,110**	
Total U.S. TEOR		**417**			**1,126**	

For an operator of proved TEOR reserves, the decision to continue production depends only on going-forward operating costs. Sunk costs (such as drilling and completion costs) are not relevant to continued operation. The TEEM model captures all operating costs for TEOR production, including lifting costs, steam generation and injection costs, well maintenance, water treatment/disposal, and other costs. Costs are determined on a $/bbl basis in real, inflation-adjusted terms and then compared with realized wellhead prices in each future year to determine economic viability of continued operation.

The two most critical technical drivers controlling the economics of proved TEOR reserves are well productivity and the steam/oil ratio. Fuel costs for generating steam constitute the largest single operating cost for TEOR. Today, nearly all fuel that is burned to raise steam for steamfloods in California is natural gas purchased under long-term supply contracts, whereas 15 years ago lease crude was used to generate fully 55% of steam requirements. A few coal-fired units remain in operation, but air quality regulations require that all new boilers must be natural gas fired.

The steam/oil ratio varies from an efficient 2.47 barrels of steam/barrels of oil (BS/BO) at Cymric field to a much less favorable 8.43 BS/SO at the relatively less mature Kern Front field, which as a new steamflood would be expected to require extra initial heat input (Table 6-3). The state-wide steam/oil ratio averages 3.7 BS/BO, which is down significantly from more than 5.0 BS/BO during the early 1980's. The lower, more favorable steam/oil ratio is a major reason why current operations still can be profitable at wellhead prices of $10/bbl.

California currently has a total of approximately 20,000 producing wells within steamflood projects. Some of these wells produce at rates of over 100 BOPD and are highly economic, whereas other wells in the same field produce at only 1 to 2 BOPD and are marginal or sub-economic. This variation in productivity provides a basis for shutting in and eventually abandoning wells over time, simulating the behavior of a typical field operator (indeed California averages nearly 1,000 abandoned TEOR production wells annually, primarily due to low productivity).

Within the TEEM model, California TEOR wells are grouped into productivity classes and the operating costs of each well class is separately assessed in each future year. If wellhead oil prices fall significantly below production costs (more than 20% for two consecutive years, to capture the potential for rebounding prices), then the wells in that productivity category are shut in and eventually abandoned. Over time, and assuming favorable economic conditions, large numbers of new wells would need to be drilled to maintain overall field production, as is simulated in the following Inferred TEOR Reserves Submodule.

During 1996, the average shut-in threshold price for TEOR production is estimated to have varied from approximately $6/bbl at Cymric field to over $13/bbl at Kern Front field, while production costs averaged about $7/bbl statewide (Figure 6-3). The shut-in prices are generally consistent with steam/oil ratios and per-well productivity for each field.

Inferred TEOR Reserves Module: These are new reserve additions that are expected to be drilled during the next 20 years to replace and expand upon existing proved reserves. Inferred reserves are grounded on identified and well-documented heavy oil resources, as well as on nearby well performance. Although by nature less reliable than proved reserves, the economics of inferred TEOR reserves can be modeled with far greater confidence than, for example, those of undiscovered light oil resources. This is because TEOR development generally takes place in areas that have been depleted by primary and secondary oil production, so that reservoir properties are already relatively well understood. Furthermore, most new TEOR development is expected to take place within fields that already have operating steamfloods, facilitating analysis of expansion economics. (In contrast, conventional light oil E&P is characterized by much higher exploration risk and must be modeled using statistical methods, such as field-size distribution and finding rates.)

The undeveloped acreage within the California heavy oil fields with potential for steamflood expansion was estimated based on detailed field studies, and is summarized in Table 6-5. It is estimated that a total of 27,000 future TEOR wells could be developed on over 50,000 undeveloped acres of heavy oil resources in California. Midway-Sunset, Coalinga, and Kern River fields account for most of the undeveloped acreage, although the actual pace of expansion is linked to economic performance and is expected to vary widely by field and area. Pattern size for vertical wells is based on current spacing practice and also varies widely by field, from tightly developed patterns at Kern River field (1.0-acre spacing) to the more widely spaced San Ardo and Mt. Poso fields (7.5 to 10.0 acres).

Table 6-5
Estimate of Undeveloped Acreage in California for TEOR Inferred Reserves

Field	Total Field Area (acres)	Active & Terminated TEOR Area (acres)	Remaining Undeveloped TEOR Area (acres)	Pattern Size (acres)	Remaining Well Locations
Midway-Sunset	17,000	7,500	9,500	1.0	9,500
Kern River	10,270	8,100	2,170	1.0	2,170
South Belridge	9,155	6,900	2,255	2.0	1,128
Coalinga	15,008	3,650	11,358	2.0	5,679
Cymric	4,550	1,400	3,150	2.0	1,575
Lost Hills	4,110	1,000	3,110	2.0	1,555
San Ardo	4,390	1,950	2,440	7.5	325
Mt. Poso	3,805	3,100	705	10.0	71
Kern Front	5,495	3,450	2,045	3.0	682
Placerita	870	120	750	1.5	500
Edison	7,935	2,000	5,935	3.5	1,696
McKittrick	3,665	680	2,985	2.5	1,194
Round Mountain	2,145	0	2,145	5.0	429
Cat Canyon	2,420	440	1,980	4.0	495

Whereas the economics of proved reserves are controlled only by operating costs, expanding steamflood operations to add new inferred reserves requires additional capital expenditures in drilling and field development. Consequently, higher realized wellhead oil prices (or lower fuel costs) are needed to attract development of inferred reserves. Capital costs modeled include drilling and completing production and injection wells, central plant facilities, steam manifolds and flowlines, production gathering systems, and other costs. Steam generation capital costs for new projects are assumed to be carried by the electricity rate base, so that steam is charged to the oil field at only marginal cost.

The economic decision to continue or expand development of inferred TEOR reserves depends on the profitability of new development. For each future year, the model evaluates the economic performance of drilling and operating new wells within 14 California heavy oilfields. If the discounted net cash flow analysis indicates that real return on investment (ROI) is greater than an assumed 11.5% cost of capital, then the model elects to drill new wells within that field during that particular year. The pace of drilling is linked directly to profitability, so that drilling in a portion of the field that achieves 20% ROI will take place faster than in more marginally economic areas. At very high oil prices and low gas prices, the most favorable economic scenario, over 2,000 new TEOR wells are predicted to be drilled and completed in California, compared with about 935 actual TEOR completions during 1996. New drilling effectively converts inferred reserves into proved reserves within the model, which then are produced at current field R/P ratios.

The TEEM model captures the development and penetration of new field management and extraction technologies – such as improved recovery/acre from horizontal drilling and 4-D seismic monitoring – and forecasts that heavy oil development costs will continue to fall during the next 20 years.

TEOR Forecast to 2010. Maintaining or increasing future TEOR production will require massive investment in the development of new steamflood zones and field areas, including the drilling of approximately 1,000 additional wells each year to develop new reserves ("inferred reserves"). In the short term, however, sharp drops in heavy oil prices or increases in fuel costs can cause production to be curtailed.

Using the TEEM model, we performed a forecast of California thermal EOR production to year 2010 (Figure 6-2). The oil price track assumed was the relatively conservative oil price track cited by USDOE in their Annual Energy Outlook 1998. Under this economic scenario, the world oil price varies but generally averages about $18/BO.

The impact of technological improvement on long-term California TEOR production is profound. Figure 6-2 illustrates forecasted production for three technology scenarios, all under the relatively low USDOE oil price. Under the Low Technology scenario, due to low R&D investment and slow technology transfer, technological improvements are limited to 2%/year reductions in drilling and completion costs. California TEOR production is forecasted to decline at about 2%/year to 285,000 BOPD in 2010, as new development is hindered by high costs and unfavorable economics.

The Reference Technology scenario assumes penetration of horizontal well technology over a 40-year period, slowing the production decline to about 1%/year. Thermal EOR production under the Reference Technology case is projected to decline to about 316,000 BOPD in 2010.

Finally, the High Technology scenario (20-year penetration of horizontal wells; 3%/year D&C cost reductions) enables TEOR production to stabilize at close to current levels. After 2007, once development costs for inferred reserves have dropped below expansion thresholds in many fields, production is forecast to grow at about 1% to 2%/year, reaching 387,000 BOPD by 2010. California TEOR is so sensitive to technology because much of the resource is only marginally economic at low to moderate oil prices. (Of course, a higher oil price track would also lead to increased investment and significantly higher TEOR production.)

Cogeneration

Cogeneration, the joint production of electricity and process steam from a common facility, is an important activity in the operation and economic performance of California thermal EOR projects. Cogeneration can greatly reduce the effective cost of steam for TEOR operations, because in practice most of the capital cost for steam generation is recovered through the electric utility rate determination. Steamflood cogeneration is considered a qualifying facility under the Public Utilities Regulatory Policies Act of 1978 (PURPA).

Reliance on cogeneration has grown steadily in California thermal EOR projects throughout the 1980's and early 1990's. In 1997, a total of 2,071 MW of installed cogeneration capacity was developed in California TEOR fields (Table 6-6). Nearly all cogeneration is gas-fired, mostly using natural gas purchased under long-term contract from the Kern River and other Rocky Mountain pipelines. An average total of 625 MMcfd of natural gas fuel was consumed in 1997. Several small older cogeneration facilities are coal-fired.

Table 6-6
Summary of Cogeneration in California TEOR Fields (1998)

Field	Projects	Power Capacity (MW)	Natural Gas Usage (MMcfd)	Cogenerated Steam Injected (MBS/D)	Total Steam Injected (MBS/D)	Percent Cogen/ Total
Kern River	10	812	220	371	371	100%
Midway-Sunset	10	415	121	281	478	59%
Kern Front	4	189	44	25	25	100%
Placerita	2	142	49	20	20	100%
San Ardo	3	82	24	53	53	100%
South Belridge	2	75	22	60	291	21%
Coalinga	5	59	22	65	87	75%
Mt. Poso	1	50	(coal-fired)	3	11	29%
Cymric	4	27	33	34	76	44%
Lost Hills	1	10	4	8	37	22%
Total (10 Fields)	**42**	**1,861**	**539**	**920**	**1,449**	**63%**
Total California TEOR	**51**	**2,071**	**625**	**934**	**1,521**	**61%**

Cogeneration produced an estimated 61% of total TEOR field steam requirements. Cogeneration is particularly significant at Kern River and Midway-Sunset fields. Many fields generate more than 100% of field power requirements; the remainder is sold to the power grid. Currently, this surplus power is almost equally shared between Pacific Gas & Electric Company and Southern California Edison Company. However, certain fields – such as South Belridge, Lost Hills, and Mount Poso – do not have sufficient cogeneration and rely on grid purchases for three-quarters of their power needs. Table 6-7 provides a detailed catalog of cogeneration facilities at California thermal EOR fields.

Air emissions are tightly controlled in California and restrictions on emissions could future impact heavy oil development. Emissions of CO_2, CO, SO_x, NO_x, and VOC are the main constituents that are regulated. Using currently available technology, natural gas is the only acceptable fuel for generating steam and electricity at most TEOR fields in California.

Innovative Technologies for Thermal EOR

The key technology advances affecting thermal EOR during the next 10 years are expected to be:

- Increased application of horizontal drilling for production wells to boost recovery/acre
- Use of slimhole injector wells to reduce capital costs, and
- Improved reservoir characterization and monitoring using 4-D seismic and other methods for both improved recovery and lower costs.

Horizontal drilling technology for TEOR has been pioneered by Cal Resources LLC (Shell) at Midway-Sunset and Coalinga fields (Speirs and Warren, 1994). Although Shell’s horizontal wells cost 3 to 4 times as much as vertical wells on a per-foot basis, they produce at 10 to 15 times the rate and are economically as well as technically viable for many heavy oil reservoirs in California. The model assumes penetration of horizontal production well technology over a 20- to 40-year period, reaching a maximum 90% penetration for development of inferred reserves. Horizontal drilling is expected to increase oil recovery by about 20% per acre and also to accelerate the production of reserves to less-discounted early years of the project.

The use of 4-D seismic monitoring of steamfloods — 3-D seismic data collected over time — is another potential breakthrough technology that can help make TEOR production more efficient. 4-D seismic can be used to monitor the flow of steam and fluids through the heavy oil reservoir (Waite et al., 1997). Better well positioning and operation based on 4-D seismic data can optimize steam flow through the reservoir, reducing bypassed oil zones and further improving steam/oil ratios. Apart from breakthrough technology, overall drilling and completion costs are projected to fall by a gradual 2 to 3% per year, which is the long-term secular trend for oilfield costs due to a variety of incremental technological improvements.

Table 6-7
California Thermal EOR Cogeneration Facilities (1998)

Field	Lease Operator	Fuel Type	Maximum Power Output (MW)	Surplus Power Buyer*	Approx. Plant Cost ($ millions)	Fuel Requirements
Belridge S.	Aera	Gas	9.6	None	12.0	6.0 MMcf/d
Belridge S.	Aera	Gas	65.0	PGE	53.0	15.6 MMcf/d
Coalinga	Chevron	Gas	5.8	PGE	6.6	2.8 MMcf/d
Coalinga	Chevron	Gas	5.8	PGE	5.5	2.8 MMcf/d
Coalinga	Chevron	Gas	5.8	PGE	6.0	2.8 MMcf/d
Coalinga	Coalinga Cogen	Gas	34.9	PGE	34.2	11.4 MMcf/d
Coalinga	Shell	Gas	7.0	PGE	8.0	2.0 MMcf/d
Cymric	Chevron	Gas	10.8	PGE	10.0	4.8 MMcf/d
Cymric	Chevron	Gas	6.0	PGE	5.5	2.1 MMcf/d
Cymric	Chevron	Gas	6.0	PGE	5.0	2.7 MMcf/d
Cymric	Torch	Gas	3.8	PGE	3.9	2.0 MMcf/d
Elk Hills	Bechtel	Gas	46.0	PGE	46.0	10.3 MMcf/d
Jasmin	Rio Bravo Jasmin	Coal	37.0	SCE	75.0	140,000 Tons/yr
Kern Front	Oxy U.S.A.	Gas	47.0	PGE	n/a	11.3 MMcf/d
Kern Front	Oxy U.S.A.	Gas	47.0	PGE	n/a	11.3 MMcf/d
Kern Front	Oxy U.S.A.	Gas	48.0	PGE	n/a	9.9 MMcf/d
Kern Front	Oxy U.S.A. & Stockdate O&G	Gas	47.0	PGE	n/a	11.3 MMcf/d
Kern River	ARCO	Gas	7.9	PGE	5.8	2.6 MMcf/d
Kern River	ARCO	Gas	7.5	PGE	5.1	2.6 MMcf/d
Kern River	ARCO	Gas	3.7	PGE	3.2	1.3 MMcf/d
Kern River	Chevron	Gas	42.0	PGE	32.5	11.8 MMcf/d
Kern River	DAI	Gas	29.0	PGE	n/a	5.5 MMcf/d
Kern River	Aera	Gas	28.0	PGE	33.1	7.3 MMcf/d
Kern River	Aera	Gas	46.0	PGE	57.0	9.5 MMcf/d
Kern River	Texaco (Omar)	Gas	300.0	SCE	150.0	85 MMcf/d
Kern River	Texaco (Sycamore)	Gas	300.0	SCE	165.0	85 MMcf/d
Kern River	Texaco (Live Oak)	Gas	48.0	PGE	n/a	9.4 MMcf/d
Lost Hills	Texaco	Gas	10.0	PGE	8.0	3.5 MMcf/d
McKittrick	Texaco	Gas	10.0	PGE	10.0	5.0 MMcf/d
Midway-Sunset	ARCO	Gas	6.0	PGE	5.5	1.9 MMcf/d
Midway-Sunset	ARCO	Gas	234.0	SCE / PGE	144.0	68.0 MMcf/d
Midway-Sunset	Berry Petroleum	Gas	37.0	PGE	32.5	10.5 MMcf/d
Midway-Sunset	Berry Petroleum	Gas	16.8	PGE	17.5	4.0 MMcf/d
Midway-Sunset	Chevron	Gas	12.5	PGE	10.0	7.2 MMcf/d
Midway-Sunset	Oxy U.S.A.	Gas	48.2	PGE	50.0	9.9 MMcf/d
Midway-Sunset	Aera	Gas	4.0	PGE	6.0	1.2 MMcf/d
Midway-Sunset	Texaco	Gas	10.0	PGE	8.0	3.5 MMcf/d
Midway-Sunset	Texaco	Gas	40.0	PGE	20.0	11.0 MMcf/d
Midway-Sunset	Torch	Gas	6.0	PGE	6.0	4.0 MMcf/d
Mount Poso	MacPherson Oil	Coal	49.5	PGE	100.0	236,000 Tons/yr
Placerita	AES	Gas	99.9	SCE	115.0	28.0 MMcf/d
Placerita	ARCO	Gas	42.0	SCE	32.0	20.5 MMcf/d
Poso Creek	Mid-State Engineering	Coal	37.0	PGE	75.0	132,000 Tons/yr
San Ardo	Aera	Gas	6.2	None	8.2	3.8 MMcf/d
San Ardo	Texaco	Gas	38.0	PGE	37.9	10.2 MMcf/d
San Ardo	Texaco	Gas	38.0	PGE	35.3	10.2 MMcf/d
Wilmington	INDECK	Gas	80.0	SCE	48.0	22.5 MMcf/d
Yorba Linda	Columbine Asso.	Gas	-	Temporarily Suspended		
State Totals			**2,069.7**		**1,491.3**	**551 MMcf/d Gas**

*SCE = Southern California Edison Company, PGE = Pacific Gas & Electric Company
Source: California Division of Oil, Gas and Geothermal Resources; Operator Data

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CONTACT INFORMATION

Figure A-1 CO_2-EOR Projects

Figure A-2 Thermal EOR Projects

Figure A-3 Other Gas EOR Projects

Key to Figures:
Succ = Successful
Prom = Promising
TETT = Too Early To Tell

Actively Producing CO2-EOR Projects in the US

Source: Oil and Gas Journal, April 20, 1998.
Other Sources: Operator Data.

Operator	Field Name	Pay zone	State	Loc	County	Start Date	Proj Area (acres)	Wells Production (number)	Wells Injection (number)	Depth (ft)	Curr EOR Reserves MMBO	Tot Prod b/d	EOR Prod b/d	Proj eval	Est EOR Power Usage (hp)	Contact Person Name	Contact Person Telephone
Chevron	Rangely Weber Sand	Weber SS	CO	NW	Rio Blanco	Oct-86	15,000	378	259	6,400	74.0	23,881	13,881	Succ.	69,405	Keith Eilers	307-783-9300
Mobil	McElmo Creek	Ismay Desert Creek	UT	NE?	San Juan	Feb-85	13,440	143	120	5,600	*76.7*	7,000	3,500	Succ.	17,500	Kirk Houston	915-688-1669
Amoco	Wertz	Tensleep	WY	SW	Carbon, Sweetwater	Oct-86	1,500	28	41	6,000	17.0	1,000	800	Succ.	4,000		
Amoco	Lost Soldier	Tensleep	WY	SW	Sweetwater	May-89	1,400	54	60	5,000	10.2	4,500	4,050	Succ.	20,250		
Amoco	Lost Soldier	Darwin-Madison	WY	SW	Sweetwater	May-89	790	20	41	5,400	*17.5*	1,600	1,100	Succ.	5,500		
Amoco	Lost Soldier	Cambrian	WY	SW	Sweetwater	Jun-96	120	5	4	7,000	*14.8*	1,350	1,080	Succ.	5,400		
TOTAL ROCKY MOUNTAINS													**24,411**		122,055		
Texaco	Paradis	Lower 9,000-ft	LA		St. Charles	Feb-82	347	20	1	10,400	*1.1*	100	100	Prom.	500		
Texaco/MVP	Paradis	#16 Sand	LA		St. Charles	May-89	298	4	2	9,950	*3.0*	270	270	Prom.	1,350		
JP Oil	West Mallalieu	Lower Tuscaloosa	LA		Lincoln	Nov-86	5,760	6	2	10,365	*2.5*	225	225	Succ.	1,125	Boyd Getz	318-234-1170
JP Oil	Little Creek Field	Lower Tuscaloosa	MS		Lincoln & Pike	Dec-85	6,200	19	19	10,750	13.9	1,317	1,317	Prom.	6,585	Boyd Getz	318-234-1170
JP Oil	Olive	Lower Tuscaloosa	MS		Pike	Oct-87	1,280	8	4	10,500	*3.5*	320	320	Succ.	1,600	Boyd Getz	318-234-1170
TOTAL GULF COAST													**2,232**		11,160		
Anadarko	Bradley	Not in O&GJ	OK?													Tom Rushing	281-874-3389
Anadarko	Purdue	Not in O&GJ	OK?													Tom Rushing	281-874-3389
Mobil	Postel	Morrow	OK	NW	Texas	Nov-95	11,000	140	110	6,150	0.0	5,800	4,600	TETT	23,000	Meirick Cox	580-545-5069
Oxy USA	Northeast Purdy	Springer	OK		Garvin	Sep-82	3,400	75	44	9,400	16.9	2,600	1,950	Succ.	9,750		
Henry Petroleum	EVWB (Sho-Vel-Tum)	Sims	OK	E	Stephens	Sep-82	1,100	51	16 CO_2, 23 H_2O	6,200	4.5	1,700	1,700	Succ.	8,500	Keith Mayberry	580-444-2751
Henry Petroleum	EVWB	Aldridge	OK	E	Stephens	Nov-98	98	6			0.8					Keith Mayberry	580-444-2751
Stanberry Oil	Hansford Marmaton	Marmaton	TX	N	Hansford	Jun-80	2,010	9	10	6,500	2.0	440	440	Succ.	2,200		
Mitchell Energy	Alvord South Field	Caddo	TX	N	Wise	Jan-80	2,291	11	1	5,700		60	60	Prom.	300		940-683-6170
TOTAL MID-CONTINENT													**8,750**		43,750		
Altura	Anton Irish	Clearfork	TX	W	Hale	Apr-97	1,600	82	40	5,900	*54.8*	5,000	1,000	TETT	5,000	Ron Lanclose	281-552-1171
Altura	Bennett Ranch Unit	San Andres	TX	W	Yoakum	Jun-95	160	15	7	5,200	-1.1	3,200	100	TETT	500	Lloyd Stark	281-552-1000
Altura	Cedar Lake	San Andres	TX	W	Gaines	Aug-94	2,500	175	166	4,700	*69.7*	6,365	1,744	TETT	8,720	Lloyd Stark	281-552-1000
Altura	Cowden North	San Andres	TX	W	Ector	Feb-95	200	30	18	4,200	*192.7*	17,600	839	TETT	4,195	Lloyd Stark	281-552-1000
Altura	Cross Mid	Devonian	TX	W	Crane & Upton	Jul-97	1,326	12	6	5,400	*0.5*	50	0	TETT	-	Lloyd Stark	281-552-1000
Altura	Cross North	Devonian	TX	W	Crane & Upton	Apr-72	1,155	25	12	5,300	22.0	1,345	1,345	Succ.	6,725	Lloyd Stark	281-552-1000
Altura	Cross South	Devonian	TX	W	Crockett	Jun-88	1,200	21	10	5,200	*17.2*	1,570	1,500	Prom.	7,500	Lloyd Stark	281-552-1000
Altura	Slaughter (Central Mallet)	San Andres	TX	W	Hockley	Jan-84	6,412	175	134	4,900	*48.2*	4,400	2,600	Succ.	13,000	Lloyd Stark	281-552-1000
Altura	Slaughter Estate	San Andres	TX	W	Hockley	Dec-84	5,700	185	161	4,950	55.5	7,400	4,200	Succ.	21,000	Lloyd Stark	281-552-1000
Altura	Slaughter Frazier	San Andres	TX	W	Hockley	Dec-84	1,600	59	52	4,950	*27.4*	2,500	1,600	Succ.	8,000	Lloyd Stark	281-552-1000
Altura	Wasson (Denver)	San Andres	TX	W	Yoakum & Gaines	Apr-83	27,848	735	365	5,200	90.0	36,600	30,700	Succ.	153,500	Bichlan Thai	281-552-1057
Altura	Wasson (South)	Clearfork	TX	W	Gaines	Jan-86	4,960	105	70	6,700	86.8	5,000	1,000	Prom.	5,000	Bichlan Thai	281-552-1057
Altura	Wasson ODC	San Andres	TX	W	Yoakum	Nov-84	7,800	293	290	5,100	*145.8*	13,313	9,300	Succ.	46,500	Bichlan Thai	281-552-1057
Amerada Hess	Adair San Andres Unit	San Andres	TX	W	Gaines	Nov-97	5,338	82	63	4,852		1,800		TETT		Ron Greenroad	915-758-6700
Amerada Hess	Seminole Unit-Main Pay Zone	San Andres	TX	W	Gaines	Jul-83	15,699	408	160	5,300	*350.4*	32,000	30,000	Succ.	150,000	Ron Greenroad	915-758-6700
Amerada Hess	Seminole Unit-ROZ Phase 1	San Andres	TX	W	Gaines	Jul-96	500	15	10	5,500	*11.0*	1,000	500	TETT	2,500	Ron Greenroad	915-758-6700
ARCO	Wasson-Willard	San Andres	TX	W	Yoakum	Jan-86	8,000	282	226	5,100	*65.7*	6,000	4,900	Succ.	24,500	Cliff Yoakum	806-592-4970
Burlington Resources	El Mar	Delaware	TX	W	Loving	Apr-94	6,000	69	56	4,500	*6.9*	630	630	TETT	3,150		
Chevron	Goldsmith	San Andres	TX	W	Ector	Dec-96	330	16	9	4,200				TETT		Gary Hyatt	915-687-7363
Chevron	McElroy	Grayburg	TX	W	Crane	Nov-82	140	23	11	2,800						Joe P. Brinkman	915-687-7251
Conoco	Ford Geraldine Unit	Delaware	TX	W	Reeves & Culberson	Feb-81	3,850	91	69	2,680	13.0	600	600	Succ.	3,000		
Conoco	Maljamar	Grayburg-San Andres	NM	SE	Lea and Eddy	Jan-89	1,760	94	2	3,650-4,200	*15.3*	1,400	100	TETT	500		
Enron	Two Freds (inactive)	Bell Canyon	TX	W	Loving, Ward	Jan-74	1,583			4,820	3.4						
Exxon	Cordona Lake	Devonian	TX	W	Crane	Dec-85	2,084	30	20	5,500	*12.0*	1,100	400	Prom.	2,000	Ray Massa	713-656-2660
Exxon	Means	San Andres	TX	W	Andrews	Nov-83	8,500	484	284	4,300	16.6	10,700	7,200	Succ.	36,000	Ray Massa	713-656-2660

Figure A-1
CO_2-EOR Projects and Contacts

Source: Oil and Gas Journal, April 20, 1998.
Other Sources: Operator Data.

Operator	Field Name	Pay zone	State	Loc	County	Start Date	Proj Area (acres)	Wells Production (number)	Wells Injection (number)	Depth (ft)	Curr EOR Reserves MMBO	Tot Prod b/d	EOR Prod b/d	Proj eval	Est EOR Power Usage (hp)	Contact Person Name	Contact Person Telephone
Exxon	Slaughter	San Andres	TX	W	Hockley	May-85	569	24	11	4,900	*7.7*	700	550	Succ.	2,750	Ray Massa	713-656-2660
Exxon	Wasson (Cornell Unit)	San Andres	TX	W	Yoakum	Jul-85	1,923	62	50	4,500	*17.5*	1,600	1,100	Prom.	5,500	Ray Massa	713-656-2660
Fasken	Hanford	San Andres	TX	W	Gaines	Jul-86	1,120	23	26	5,500	6.3	600	600	Succ.	3,000	Jimmy Davis	915- 687-2008
Fasken	Hanford East	San Andres	TX	W	Gaines	Mar-97	340	7	4	5,500	*1.2*	110	50	TETT	250	Jimmy Davis	915- 687-2008
Fina	East Penwell (SA) Unit	San Andres	TX	W	Ector	May-96	540	34	13	4,000	*6.3*	575	100	Prom.	500	Ed Pittinger	915-688-0607
Fina	West Brahaney Unit	San Andres	TX	W	Yoakum	Jun-96	400	15	8	5,300		79		TETT		Ken Fairchild	915-687-0575
Mobil	GMK South	San Andres	TX	W	Gaines	Jan-82	1,143	24	24	5,400	*14.2*	1,300	400	Succ.	2,000	Dan Callens	806-229-6081
Mobil	Mallet Unit (Part of Slaughter)	San Andres	TX	W	Hockley and Cochran	Nov-91	4,780			5,000						Steve Bearden	806-237-5313
Mobil	Salt Creek	Canyon Reef	TX	W	Kent	Oct-93	12,000	85	48	6,300	*284.7*	26,000	12,000	Succ	60,000	Steve Bearden	806-237-5313
Mobil	Slaughter (3 proj)	San Andres	TX	W	Hockley	Jun-89	2495?	84	47	5,000	*74.5*	6,800	2,000	Succ.	10,000	Forest Collier	915-688-2085
Mobil	Wasson-Mahoney	San Andres	TX	W	Yoakum	Oct-85	640	30	26	5,100	*18.6*	1,700	300	Succ.	1,500	Forest Collier	915-688-2085
Orla Petco	Ford East	Delaware, Ranosen	TX	W	Reeves	Jul-95	1,953	12	8	2,680	*0.7*	60	60	TETT	300	Forest Collier	915-688-2085
Oxy USA	Dollarhide North	Devonian	TX	W	Andrews	Nov-97	1,280	22	4	8,000		2,000		TETT		Bill Lovett	915-685-5650
Oxy USA	Welch South	San Andres	TX	W	Dawson	Apr-96	900	38	19	4,550	0.0	1,900	950	Prom.	4,750	Bill Lovett	915-685-5650
Oxy USA	Welch West	San Andres	TX	W	Terry	Oct-97	640	30	13	4,900		240		TETT		Bill Lovett	915-685-5650
Pennzoil	SACROC Unit (Kelly-Snyder Field)	Canyon Reef	TX	W	Scurry	Jan-72	49,900	325	57	6,700	99.6	9,000	9,000	Succ.	45,000	David Higgins	915-574-7024
Phillips	Cowden South	San Andres	TX	W	Ector			42	16							Jerry Michaelis	915-368-1309
Phillips	Vacuum East	Grayburg, San Andres	NM	W	Lea	Sep-85	4,900	192	100	4,500	30.0	7,800	4,700	Succ.	23,500	Lee Owens	505-391-5334
Southwest Royalty (Conoco?)	Huntley East	San Andres	TX	W	Garza	Jan-94	700	38	15	3,100	4.0	450	130	TETT	650	Nelson Patton	915-686-9927
Southwest Royalty (Conoco?)	Huntley South	San Andres	TX	W	Garza	Jan-94	560	31	8	3,400	2.8	1,300	150	TETT	750	Nelson Patton	915-686-9927
Spirit Energy	Dollarhide	Devonian	TX	W	Andrews	May-85	4,027	92	76 (39 CO_2)	7,800	18.8	2,350	900	Yes	4,500	Mike Gelds	915-685-6753
Spirit Energy	Dollarhide	Clearfork	TX	W	Andrews	Nov-95	160	21	4	6,500		355		TETT		Mike Gelds	915-685-6753
Spirit Energy	Reinecke	Cisco Canyon Reef	TX	W	Borden	Jan-98	700	25	5	6,800		1,900		TETT		Craig Van Horn	915-685-6807
Texaco	Mabee	San Andres	TX	W	Andrews-Martin	Jan-92	12,824	377	274	4,700	17.1	6,500	5,500	Prom	27,500	Mike Argo	915-682-2906
Texaco	Slaughter Sundown	San Andres	TX	W	Hockley	Jan-94	8,685	280	187	4,950	*73.4*	6,700	4,400	TETT	22,000	Scott Wehner	915-682-2954
Texaco	Vacuum	San Andres	NM	SE	Lea	Jul-97	2,240	95	85	4,550	33.0	3,900		TETT		Scott Wehner	915-682-2954
Whiting	Sable	San Andres	TX	W	Yoakum	Mar-84	825	33	32	5,200	*5.7*	520	300	Succ.	1,500		
Wiser Oil	Wellman	Wolfcamp	TX	W	Terry	Jul-83	1,400	14	9	9,800	*15.3*	1,400	1,400	Succ.	7,000		
TOTAL PERMIAN BASIN													**144,848**		724,240		
ARCO	Kuparuk River	A&C Sands	AK			6/88-12/96	62,000	163	142	6,000	*1314.0*	120,000	23,500	Succ.	117,500		
ARCO	Prudhoe Bay	Sadlerochit	AK			12/82-2/87	55,000	350	130	8,800	*1971.0*	180,000	50,000	Succ.	250,000		
TOTAL ALASKA (22% CO2)													**16,170**		80,850		
Total U.S. CO2-EOR													**196,411**		982,055		

Operator	Field	State	County	Date Begun	Prod Wells	Inject Wells	Depth Ft	Total Prod BOPD	EOR Prod BOPD	Estim Power (hp)	Outlook	Contact	Telephone
AERA	Belridge	CA	Kern	Jan-61	2,900	975	400-1,400	37,000	37,000	27,750	Succ.	Ed Neilands	661-665-5341
AERA	Cat Canyon	CA	Santa Barbara	Mar-85			2,500-4,500				TETT	Ed Neilands	661-665-5341
AERA	Coalinga	CA	Fresno	Jan-80	190	22	825-1,650	3,580	3,580	2,685	Succ.	Ed Neilands	661-665-5341
AERA	Coalinga	CA	Fresno	Nov-87	172	48	650-1000	5,850	5,850	4,388	Succ.	Ed Neilands	661-665-5341
AERA	Cymric	CA	Kern	Dec-86	100	46	1,000	5,600	5,600	4,200	Succ.	Ed Neilands	661-665-5341
AERA	Kern River	CA	Kern	Jan-70	840	270	150-1,500	10,800	10,800	8,100	Succ.	Ed Neilands	661-665-5341
AERA	Lost Hills	CA	Kern	Jun-90	100	36	350	4,070	4,070	3,053	Prom.	Ed Neilands	661-665-5341
AERA	Lost Hills	CA	Kern	Jun-90	125	37	200	4,500	4,500	3,375	Prom.	Ed Neilands	661-665-5341
AERA	McKittrick	CA	Kern	Mar-88	145	115	600	4,500	4,500	3,375	Prom.	Ed Neilands	661-665-5341
AERA	Midway-Sunset	CA	Kern	Oct-70	381	32	950	12,000	12,000	9,000	Succ.	Ed Neilands	661-665-5341
AERA	Midway-Sunset	CA	Kern	Jan-79	66	0	900	800	800	600	Succ.	Ed Neilands	661-665-5341
AERA	Midway-Sunset	CA	Kern	Jan-89	78	8	800	1,600	1,500	1,125	Prom.	Ed Neilands	661-665-5341
AERA	Midway-Sunset	CA	Kern	Jan-83	205	25	1,080	4,300	4,300	3,225	Succ.	Ed Neilands	661-665-5341
AERA	Midway-Sunset	CA	Kern	Jan-71	650	34	500-1,400	6,600	6,600	4,950	Succ.	Ed Neilands	661-665-5341
AERA	Midway-Sunset	CA	Kern	Jan-80	145	8	1,300	2,200	2,200	1,650	Succ.	Ed Neilands	661-665-5341
AERA	Mount Poso	CA	Kern	Jan-71	75	16	1,500-1,800	3,100	3,100	2,325	Succ.	Ed Neilands	661-665-5341
AERA	North Midway-Sunset	CA	Kern	Nov-67	376	21	1,000	10,750	10,750	8,063	Succ.	Ed Neilands	661-665-5341
AERA	San Ardo	CA	Monterey	Jun-68	100	28	2,300	1,930	1,930	1,448	Succ.	Ed Neilands	661-665-5341
AERA	San Ardo	CA	Monterey	Mar-80	42	14	2,100	7,350	7,350	5,513	Succ.	Ed Neilands	661-665-5341
AERA	South Belridge	CA	Kern	Jan-69	510	263	1,000	43,200	43,200	32,400	Succ.	Ed Neilands	661-665-5341
AERA	South Belridge	CA	Kern	Jan-65	50		1,000	460	460	345	Succ.	Ed Neilands	661-665-5341
AERA	Yorba Linda	CA	Orange	Jan-71	203	11	500-1,000	1,000	750	563	Succ.	Ed Neilands	661-665-5341
ARCO	Kern River	CA	Kern	Jan-70	88	11	600	370	370	278	Succ.		
ARCO	Kern River	CA	Kern	Jan-70	87	28	1,200	1,000	1,000	750	Succ.		
ARCO	Kern River	CA	Kern	Sep-72	25	11	900	300	300	225	Succ.		
ARCO	Kern River	CA	Kern	Jan-72	80	39	800	800	800	600	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-72	63	7	1,200	1,050	1,050	788	Succ.		
ARCO	Midway-Sunset	CA	Kern	May-05	137	13	1,500	3,500	3,500	2,625	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-83	109	42	1,500	2,500	2,500	1,875	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-81	94	13	1,200	1,250	1,250	938	Succ.		
ARCO	Midway-Sunset	CA	Kern	Aug-72	130	5	1,000	900	900	675	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-84	7	0	1,300	120	120	90	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-69	98	17	1,100	2,700	2,700	2,025	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-89	127	4	1,500	1,750	1,750	1,313	Succ.		

Figure A-2
Thermal EOR Projects and Contacts in the U.S.

ARCO	Midway-Sunset	CA	Kern	Jan-77	222	32	1,200	4,500	4,500	3,375	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jun-05	69	3	700	650	650	488	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-84	87	4	800	450	450	338	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-84	49	2	800	300	300	225	Succ.		
ARCO	Midway-Sunset	CA	Kern	Mar-90	218	7	900	3,500	3,500	2,625	Succ.		
ARCO	Midway-Sunset	CA	Kern	Mar-90	314	27	900	7,200	7,200	5,400	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-88	34	8	1,100	700	700	525	Succ.		
ARCO	Midway-Sunset	CA	Kern	Jan-65	206	0	810	2,400	2,400	1,800	Succ.		
ARCO	Placerita	CA	Ventura	Jan-86	106	55	1,800	3,000	3,000	2,250	Succ.		
Berry	North Mid-Sunset	CA	Kern	Jan-65	120		1,300	1,000	700	525	Succ.	Lonnie Kerley	661-769-8811
Berry	South Mid-Sunset	CA	Kern	Jan-64	650		1,000	7,000	5,000	3,750	Succ.	Lonnie Kerley	661-769-8811
Chevron	Cymric 26W	CA	Kern	Oct-89	31	19	1,200	1,461	1,461	1,096	Succ.	Wayne Fairbanks	661-392-3818
Chevron	Cymric 35/36W	CA	Kern	May-75	130	47	1,200	6,518	6,518	4,889	Succ.	Wayne Fairbanks	661-392-3818
Chevron	Cymric 5Z	CA	Kern	Feb-91	14	4	1,200	591	591	443	Succ.	Wayne Fairbanks	661-392-3818
Chevron	Cymric 6Z	CA	Kern	Feb-86	31	19	1,200	900	900	675	Succ.	Wayne Fairbanks	661-392-3818
Chevron	Cymric 7Z	CA	Kern	May-91	30	30	600	70	70	53	Succ.	Wayne Fairbanks	661-392-3818
Chevron	Kern River-ANO	CA	Kern	May-74	177	82	1,000	3,643	3,643	2,732	Succ.	Jerry Hall	661-392-3337
Chevron	Kern River KCL 39	CA	Kern	Oct-75	67	42	1,400	379	379	284	Succ.	Jerry Hall	661-392-3337
Chevron	Kern River MC1	CA	Kern	Apr-76	120	76	960	2,072	2,072	1,554	Succ.	Jerry Hall	661-392-3337
Chevron	Kern River MCII	CA	Kern	Apr-71	129	30	960	2,274	2,274	1,706	Succ.	Jerry Hall	661-392-3337
Chevron	Kern River Sec. 3	CA	Kern	Sep-68	345	155	775	8,340	8,340	6,255	Succ.	Jerry Hall	661-392-3337
Chevron	Kern River Sec. 4	CA	Kern	Jun-78	200	64	850	3,778	3,778	2,834	Succ.	Jerry Hall	661-392-3337
Chevron	Kern River Sec. 9 HHF	CA	Kern	Jan-92	8		800	158	158	119	Succ.	Jerry Hall	661-392-3337
Chevron	Midway-Sunset Sec. 15A	CA	Kern	May-78	36	5	1,400	1,600	1,600	1,200	Succ.	Jason Rebruck	661-763-2290
Chevron	Midway-Sunset Sec. 26C	CA	Kern	Nov-75	243	81	1,300	7,381	7,381	5,536	Succ.	Jason Rebruck	661-763-2290
Chevron	Midway-Sunset Sec. 2F	CA	Kern	Oct-83	44	10	1,800	2,251	2,251	1,688	Succ.	Jason Rebruck	661-763-2290
Chevron	West Coalinga 12-D	CA	Fresno	Feb-82	89	31	1,600	617	617	463	Succ.		
Chevron	West Coalinga 13-D	CA	Fresno	May-73	182	104	1,200	2,465	2,465	1,849	Succ.		
Chevron	West Coalinga 25-D	CA	Kern	May-80	131	95	2,500	5,441	5,441	4,081	Succ.		
Chevron	West Coalinga 31A/36Z	CA	Fresno	Mar-89	70	21	1,700	1,382	1,382	1,037	Succ.		
Chevron	West Coalinga 6C	CA	Fresno	Jul-84	131	18	1,500	689	689	517	Succ.		
Exxon	Midway-Sunset	CA	Kern	Aug-90	136	75	1,500	1,200	1,200	900	Succ.		
Exxon	South Belridge	CA	Kern	Dec-87	48	24	1,250	1,100	800	600	Succ.		
Naftex	Edison 27-RT	CA	Kern	Jul-77	65	29	1,000	550	550	413	Succ.		

Oxy USA	Kern Front	CA	Kern	Nov-81	491	28	1,300-1,500	5,400	5,400	4,050	Succ.	Kevin McDonnell	661-392-7181
Saba	North Belridge	CA	Kern	Nov-65	14	0	800	166	66	50	Prom.		
Stockdale	Kern Front	CA	Kern	Feb-93	54	6	2,000	700	550	413	Succ.		
Texaco	Belridge	CA	Kern	Jun-82	75	24	650	2,000	2,000	1,500	Succ.	Ilia Lambert	661-864-3127
Texaco	Coalinga	CA	Fresno	Mar-91	38	11	1,200	650	600	450	Succ.	Ilia Lambert	661-864-3127
Texaco	Coalinga	CA	Fresno	Mar-79	36	7	850-1800	550	500	375	Succ.	Ilia Lambert	661-864-3127
Texaco	Coalinga	CA	Fresno	May-92	18	4	530	180	150	113	Succ.	Ilia Lambert	661-864-3127
Texaco	Kern River	CA	Kern	Aug-62	5,358	1325	1,000	95,000	95,000	71,250	Succ.	Ilia Lambert	661-864-3127
Texaco	McKittrick	CA	Kern	Jan-84	17	2	1,000	115	115	86	Disc.	Ilia Lambert	661-864-3127
Texaco	Midway	CA	Kern	Jan-64	1,700	159	1,500	40,000	40,000	30,000	Succ.	Ilia Lambert	661-864-3127
Texaco	Midway	CA	Kern	Jan-70	663		1,500	5,000	4,500	3,375	Succ.	Ilia Lambert	661-864-3127
Texaco	Midway	CA	Kern	Jan-82			1,500	700	600	450	Succ.	Ilia Lambert	661-864-3127
Texaco	Midway-Sunset	CA	Kern	Jan-82	47	10	1,700	1,000	900	675	Succ.	Ilia Lambert	661-864-3127
Texaco	San Ardo	CA	Monterey	Jul-87	24	7	1,900	2,200	2,200	1,650	TETT	Ilia Lambert	661-864-3127
Texaco	San Ardo	CA	Monterey	Jul-87	24	7	1,900	2,200	2,200	1,650	TETT	Ilia Lambert	661-864-3127
Texaco/Four Star	Lost Hills	CA	Kern	Aug-77	43	12	400	1,200	1,200	900	Succ.	Ilia Lambert	661-864-3127
Texaco/Four Star	Lost Hills	CA	Kern	Nov-75	65	21	200	1,000	1,000	750	Succ.	Ilia Lambert	661-864-3127
Tidelands	Wilmington	CA	Los Angeles	Apr-89	43	37	2,500	2,420	2,420	1,815	Succ.		
Tidelands	Wilmington (DOE)	CA	Los Angeles	May-96	2	2	2,500	280	280	210	TETT		
Tidelands	Wilmington (Parcel A)	CA	Los Angeles	Jun-96	3	2	2,300	620	620	465	Prom.		
Torch Operating	Cymric	CA	Kern	Jan-64	305	53	1,100	6,654	6,319	4,739	Succ.	Tommy Calhoun	661-395-5433
Torch Operating	Midway-Sunset	CA	Kern	Jan-74	52	17	1,100	727	700	525	Succ.	Tommy Calhoun	661-395-5433
Torch Operating	Midway-Sunset	CA	Kern	Jan-83	50	0	700	1,082	1,050	788	Succ.	Tommy Calhoun	661-395-5433
Torch Operating	Midway-Sunset	CA	Kern	Jun-77	79	20	1,000	1,559	1,520	1,140	Succ.	Rick Garcia	661-395-5426
Torch Operating	Midway-Sunset	CA	Kern	May-69	185	0	1,000	2,255	1,980	1,485	Succ.		
Bayou State	Bellevue	LA	Bossier	Jan-70	90	15	400	400	400	300	Succ.		
Continental Resources	Medicine Pole Hills	ND	Bowman	Jan-85	17	7	9,500	725	725	544	Succ.		
Continental Resources	Buffalo	SD	Harding	Jan-79	23	12	8,450	550	550	413	Succ.		
Continental Resources	South Buffalo	SD	Harding	Jan-83	43	19	8,450	1,420	1,420	1,065	Succ.		
Continental Resources	West Buffalo	SD	Harding	Jan-87	16	6	8,450	365	365	274	Succ.		
Carrizo	Camp Hill	TX	Anderson	Apr-89	45	24	400	200	200	150	Succ.		
Greenwich Oil	Forest Hill	TX	Wood	Sep-76	100	21	5,000	400	400	300	Prom.		
Total U.S. Thermal EOR									**445,970**	**334,478**			

Operator	Field Name	State	County	Start Date	Wells Production (number)	Wells Injection (number)	Proj Area (acres)	Total Production (BOPD)	EOR Production (BOPD)	Est EOR Power Usage (hp)	Success
Source: Oil and Gas Journal, April 20, 1998.											
Hydrocarbon EOR											
ARCO	Kuparuk River	AK		6/88-12/96	163	142	6,000	120,000	18,330	91,650	
ARCO	Prudhoe Bay	AK		12/82-2/87	350	130	8,800	180,000	39,000	195,000	
Exxon	South Pass Block 89	OCS		Dec-83	15	7	9,500	7,300	3,800	19,000	Yes
Exxon	South Pass Block 89	OCS		Jul-89	3	3	11,000	1,400	600	3,000	Yes
Hunt	Fairway	TX	Anderson/Henderson	Mar-66	92	51	9,900	6,010	6,010	30,050	Yes
Kerr-McGee	North Buck Draw (Dakota)	WY	Campbell	Dec-88	11	8	12,450	11,000	8,000	40,000	
Kerr-McGee	Sand Dune (Muddy) Unit	WY	Converse	Jul-91	15	9	12,500	10,000	10,000	50,000	Yes
Oryx	Fordoche W-12	LA	Pt. Coupee	May-80	7		13,650	47	47	235	Yes
Oryx	Fordoche W-8	LA	Pt. Coupee	May-80	8		13,200	96	96	480	Yes
True Oil	Red Wing Creek	ND	McKenzie	Jan-82	8	1	9,000	1,200			Yes
Total Hydrocarbon EOR Miscible									**85,883**	**429,415**	
Nitrogen EOR											
ARCO	Block 31	TX	Crane	Jun-49	152	77	8,600	4,350	4,350	21,750	Yes
Exxon	Jay-Little Escambia	FL	Santa Rosa	Jan-81	56	30	15,400	11,300	11,300	56,500	
Unocal	Chunchula Unit	AL	Mobile	Apr-82	33	8	18,500	7,100	2,300	11,500	
Phillips	Binger	OK	Caddo	Jan-77	55	23	10,000	1,050	1,050	5,250	
Chevron	East Painter	WY	Uinta	Nov-83	17	7	12,000	9,065	9,065	45,325	
Chevron	Painter	WY	Uinta	Jun-80	33	13	11,500	1,102	1,102	5,510	
Exxon	Hawkins	TX	Woodbine	Aug-87	24	6	4,600	900	900	4,500	
Exxon	Hawkins	TX	Woodbine	Jan-94	264	17	4,600	7,700	100	500	
Marathon	Yates	TX	Pecos/Crockett	Jan-85	619	29	1,400	54,400			
Unocal	Chunchula Unit	AL	Mobile	Apr-82	33	8	18,500	7,100	2,300	11,500	
Total Nitrogen Miscible EOR									**32,467**	**162,335**	

Figure A-3
Nitrogen and Hydrocarbon Miscible EOR Projects

B

CO_2-EOR SEQUESTRATION ECONOMIC MODEL ASSUMPTIONS AND RESULTS

The Enhanced Oil Recovery (EOR) Submodule screens the U.S. petroleum resource data base to estimate the volume and costs of EOR development and associated CO_2 sequestration. The principal assumptions and data used in this submodule are summarized as follows:

1. ***Cumulative Production & Reserves:*** Data for the cumulative volume of oil, natural gas, and natural gas liquids produced, plus remaining proved reserves were adopted from Klett et al., 1997. Data are current through 1992 for the United States. Our model specifically addresses the largest 33 petroleum provinces, which account for nearly 100% of total cumulative production and reserves in the United States (Figure B-1).

2. ***Undiscovered Resources:*** Proved petroleum reserves are by definition highly conservative measurements of actual productive potential. Even in mature provinces such as the U.S., reserves nearly always underestimate the amount of petroleum that will eventually be found and produced. For example, the oil reserve/production ratio in the U.S. has remained well below 10 years for the past several decades, yet oil reserves have not been exhausted. In fact, oil will continue to be produced in the U.S. for many more decades as new, undiscovered or inferred *resources* are developed and thereby converted into *proved reserves*. In evaluating the U.S. CO_2 sequestration potential, it is not sufficient to include only cumulative production and remaining proved reserves. Undiscovered resources, which are statistically likely to be found and developed over the next few centuries – just as they have contributed continuously to proved reserves over the past century – also must be considered.

3. ***Ultimate Recoverable.*** Sum of 1 and 2, ranked by energy value in units of barrel of oil energy equivalents (BOEE). The 33 modeled provinces account for nearly 100% of the total ultimate recoverable petroleum in the United States, which is estimated at 431 BBOE (Figure B-1).

4. ***Reservoir Province.*** The name and rank (separate rankings according to ultimate BOEE and to CO2 sequestration potential) (Figure B-2).

5. ***Reservoir Attributes.*** Average or typical depth and oil gravity, which are the two key reservoir properties that most affect applicability of CO_2 EOR. Surface characteristics, such as location (onshore or offshore or both) and approximate distance to large current anthropogenic CO_2 supplies, also have a profound impact on costs (Figure B-2).

6. ***Miscibility.*** Based on average oil gravity and reservoir depth, discussed above, an estimate of the percentage of overall oil resources that would be amenable to miscible or immiscible flooding was made. Even though most petroleum provinces were found to have suitable

average depth and oil gravity, we used a cap of 75% of the resource for both miscible and immiscible flooding. This is because the average masks wide variability in these characteristics, and also because other as yet unidentified geologic factors are likely to negatively impact EOR operations at some fields. Screening criteria outlined in Taber 1993 were used (Figure B-2).

7. ***Estimated EOR Costs.*** Four individual cost categories were defined. Data provided by Shell CO_2 Co. on the typical EOR costs of new CO_2 floods in the Permian basin were used as a basis (Schoeling, 1998). These costs (admittedly for one of the world's lowest-cost settings) were then adjusted by factors to account for potentially higher cost settings, such as offshore, deeper, or more remote EOR projects. The four cost components are: field well capital costs; pipeline capital costs; operations & maintenance costs; and CO_2 supply costs.

   Field well capital costs include drilling, completion, equipping, gathering, and (if offshore) platform costs. CO_2 pipeline capital costs are estimated for three settings: near (0 to 10 km), moderate (10 to 100 km), and far (100 to 500 km). Operations and maintenance (O&M) costs were estimated based on depth range (800-1,500 m; 1,500-2,500 m; >2,500 m), and include the relatively small costs of monitoring to ensure long-term sequestration. Offshore factors ranging from 1.5 to 3.0 were applied to the onshore costs, reflecting the typically much higher offshore capital and operating costs.

   CO_2 supply costs (delivered, high purity and pressurized to approximately 1,000 psi) represent the single largest individual cost component for a sequestration system. Several types of supply were run as sensitivities, including natural sources ($0.65/Mcf or about $12/t) and captured CO_2 from power generation plant flue gas ($3.00/Mcf or about $53/t). In addition, an advanced power plant CO_2 capture technology case was run, on the assumption that future R&D into this relatively immature area will reduce supply costs to about $2.00/Mcf or $36/t (Figure B-2).

8. ***Profitability.*** Estimated EOR costs were compared with typical sales revenues from enhanced oil recovery to determine an overall average cost or profitability for each province. This permitted a cost/sequestration supply curve to be developed. We assumed a $15/BO world oil price, less 20% for government taxes, for a typical net wellhead of $12/BO. Actual oil price was adjusted for average gravity within each petroleum province, using a typical market adjustment of $0.10/BO per degree of API gravity. Obviously, the price of oil has a powerful impact on EOR profitability. Higher oil prices would dramatically reduce net sequestration costs (Figure B-2).

9. ***EOR.*** Although cumulative production and reserves are well defined in most petroleum provinces, the target original oil in place (OOIP) has not yet been defined. We estimated OOIP from ultimate recovery and from oil gravity, according to the following relationship:

   OOIP = Ultimate Recoverable Resources / ((Average API Gravity + 5)/100)

For example, we estimate that primary and secondary recovery operations at a reservoir with average 40° API gravity crude would be expected to recover about 45% of OOIP, whereas a reservoir containing 20° API crude would recovery only about 25% of OOIP. The average Permian basin EOR project is expected to recover about 10.8% of OOIP. We used an empirical relationship between oil gravity and EOR recovery determined for 7 Permian basin EOR projects, wherein recovery ranges from about 20% of OOIP for oil gravity above 42° API to a minimum of 5% of OOIP for oil heavier than about 31° API gravity (Figure B-2).

10. ***CO_2 Sequestration Potential.*** The average net CO_2 purchased/EOR ratio in Permian basin EOR projects is about 5.8 Mcf/BO. Assuming that about 5% of CO_2 purchased is lost to the atmosphere during recycling and from insecure wellbore leakage, we assumed a worldwide average net ratio of 6.0 Mcf/BO. We further estimated that immiscible EOR resources would require a higher 10 Mcf/BO ratio. Sequestration volumes and costs were then converted into metric units of gigatonnes (Gt) and U.S. dollars per metric tonne ($/t). The 33 individual estimates were then sorted, cumulated, and graphed (Figure 4-4).

Rank				1.Cum. Prod.+Reserves				2.Undiscov. Resources			3.Ult. Recoverable			Cum %
Oil/Gas (BOEE)	USGS Code	Province Name	Country	Oil (BB)	Gas (Tcf)	NGL (BB)	Total (BBOE	Oil (BB)	Gas (Tcf)	Total (BBOE)	Oil (BB)	Gas (Tcf)	Total (BBOE)	USA BBOE
1	5047	Western Gulf	USA (SC)	26.9	251.6	7.5	76.3	14.3	2.5	14.7	48.7	254.1	91.1	21.2%
2	5044	Permian Basin	USA (SW)	32.7	94.0	6.7	55.1	1.5	15.0	4.0	40.9	109.0	59.1	34.9%
3	5097	Gulf Cenozoic OCS	USA (SC)	11.9	140.3	0.0	35.3	0.3	92.0	15.6	12.2	232.3	50.9	46.7%
4	5001	N. Alaska	USA (NW)	14.4	33.0	1.1	21.0	5.0	50.0	13.3	20.5	83.0	34.3	54.7%
5	5058	Anadarko Basin	USA (C)	2.2	93.1	2.8	20.5	0.4	13.9	2.7	5.4	107.0	23.2	60.1%
6	5048	East Texas Basin	USA (SE)	9.2	34.8	1.6	16.6	1.2	14.7	3.7	12.0	49.5	20.3	64.8%
7	5049	Louisiana-Miss. Salt B.	USA (SE)	7.1	42.8	1.3	15.5	1.2	14.7	3.7	9.6	57.5	19.2	69.2%
8	5010	San Joaquin Basin	USA (SW)	13.8	12.5	0.7	16.6	1.2	2.5	1.6	15.7	15.0	18.2	73.4%
9	5043	Palo Duro Basin	USA (SC)	1.8	48.4	2.1	12.0	0.1	0.0	0.1	4.0	48.4	12.1	76.2%
10	5014	Los Angeles Basin	USA (SW)	8.6	7.0	0.4	10.2	0.9	1.5	1.2	9.9	8.5	11.3	78.9%
11	5045	Bend Arch-Fort Worth B.	USA (SC)	4.9	11.7	0.8	7.7	0.5	1.8	0.8	6.2	13.5	8.5	80.8%
12	5022	San Juan Basin	USA (SW)	0.3	38.2	1.4	8.1	0.0	1.8	0.3	1.7	40.0	8.4	82.8%
13	5037	SW Wyoming	USA (WC)	0.8	16.3	0.4	3.9	0.1	14.0	2.5	1.3	30.3	6.4	84.3%
14	5013	Ventura Basin	USA (SW)	3.4	5.8	0.2	4.6	0.9	4.6	1.7	4.5	10.4	6.3	85.7%
15	5033	Powder River Basin	USA (NC)	2.8	2.6	0.2	3.4	1.8	2.2	2.1	4.8	4.8	5.6	87.0%
16	5064	Illinois Basin	USA (EC)	3.9	0.1	0.0	3.9	0.4	0.6	0.5	4.3	0.7	4.4	88.1%
17	5061	Southern Oklahoma	USA (C)	3.1	2.7	0.2	3.8	0.2	1.0	0.4	3.5	3.7	4.1	89.0%
18	5063	Michigan Basin	USA (NC)	1.1	3.9	0.2	2.0	0.9	6.5	2.0	2.2	10.4	3.9	89.9%
19	5062	Arkoma Basin	USA (C)	0.9	15.6	0.1	3.6	0.0	1.8	0.3	1.0	17.4	3.9	90.8%
20	5036	Wyoming Thrust Belt	USA (WC)	0.2	4.0	0.7	1.6	0.6	10.5	2.3	1.5	14.5	3.9	91.7%
21	5003	Southern Alaska	USA (NW)	1.3	7.5	0.1	2.7	0.8	2.0	1.2	2.2	9.5	3.8	92.6%
22	5055	Nemaha Uplift	USA (C)	2.7	2.8	0.3	3.5	0.1	0.4	0.2	3.1	3.2	3.7	93.5%
23	5034	Big Horn Basin	USA (NC)	2.7	1.8	0.1	3.1	0.3	0.4	0.4	3.1	2.2	3.5	94.3%
24	5031	Williston Basin (US)	USA (NC)	2.1	2.4	0.2	2.7	0.6	0.6	0.7	2.9	3.0	3.4	95.1%
25	5053	Cambridge Arch-C. KS Uplift	USA (C)	2.9	0.6	0.1	3.1	0.2	0.3	0.2	3.2	0.9	3.3	95.9%
26	5020	Uinta-Piceance Basin	USA (WC)	1.6	4.7	0.1	2.5	0.2	2.0	0.5	1.9	6.7	3.0	96.5%
27	5245	Rocky Mtn Deformed Belt	USA (WC)	0.2	13.8	0.4	2.9	0.0	0.0	0.0	0.6	13.8	2.9	97.2%
28	5060	Cherokee Platform	USA (C)	2.1	1.4	0.1	2.4	0.1	0.2	0.1	2.3	1.6	2.6	97.8%
29	5039	Denver Basin	USA (WC)	0.9	3.5	0.3	1.8	0.2	1.5	0.5	1.4	5.0	2.3	98.3%
30	5009	Sacramento Basin	USA (W)	0.1	9.2	0.1	1.7	0.0	2.8	0.5	0.2	12.0	2.2	98.9%
31	5012	Santa Maria Basin	USA (SW)	1.5	1.5	0.1	1.9	0.2	0.6	0.3	1.8	2.1	2.1	99.3%
32	5035	Wind River Basin	USA (NC)	0.5	2.8	0.1	1.1	0.1	1.5	0.4	0.7	4.3	1.5	99.7%
33	5059	Sedgwick Basin	USA (C)	0.9	2.2	0.1	1.4	0.0	0.0	0.0	1.0	2.2	1.4	100.0%
		TOTAL 33 Basins		170	913	31	352	34	264	78	234	1177	431	100.0%

Figure B-1
CO_2 Sequestration Capacity and Costs in U.S. EOR Projects

Depleted Oil Field (EOR) Sequestration Potential

Data Sources:

Masters 1998, *World Conventional Crude Oil & Natural Gas*
Klett 1997, *Ranking of the World's Oil and Gas Provinces*
Oil and Gas Journal 1998, *Worldwide Production*
Numerous other basin studies.
[1] Gottlicher and Pruschek, 1996
[2] Oil volume discounted at 10% ROI
[3] World price, gravity adj $0.1/API, less 20% gvnt taxes
[4] Miscible EOR % of OOIP from Permian B. relationship
estimated 20% of OOIP in non-waterflooded reservoirs.

Capital Costs			Operating Costs				Enhanced Oil Recovery[4]	
Field Well Costs (Shallow)	$0.80	per BO	O & M	(Shallow)	$2.70	/BO	Miscible Recovery:API Grav	
Medium (1500 m)	$1.20	per BO		Medium	$3.38	/BO	Immiscible Rec : API Grav	
Deep	$1.60	per BO		Deep	$4.05	/BO	Primary + Secondary	50%
Offshore Factor	3.0	times	Offshore Factor		1.5	times	(of OOIP @ 35 API)	
CO_2 Pipeline Costs (Near)	$0.20	per BO	CO_2 Supply Costs (Natural)		$0.65	/Mcf	Net CO_2/EOR Misc	6.0
Medium (<100 km)	$1.00	per BO		Gas Plant	$1.00	/Mcf	Net CO_2/EOR Immsc	10.0
Far (100-500 km)	$3.00	per BO		Power Plant[1]	$3.00	/Mcf	World Oil Price	$15
Offshore Factor	2.0	times	Offshore Factor		1.0	times	($/BO 40-deg API)	

4. Reservoir Province			5. Reservoir Attributes				6.Miscibility		7. Estimated EOR Costs					8. Profits[2]		9. EOR		10. Sequestration Potential				
Rank Sqstr (Gt)	Rank O&G (BOE)	Province Name	On/ Off Shore	Anthro. CO_2 Supply	Avg. Depth (m)	Oil Gravity (API)	Miscb EOR	Immis EOR	Field Cap ($/BO)	CO_2 Pipe ($/BO)	O&M Oper. ($/BO)	CO_2 Supply ($/BO)	Total Costs ($/BO)	Net Oil Price[3] ($/BO)	Profit (Loss) ($/BO)	OOIP (BBO)	EOR (BBO)	CO_2/ EOR (Mcf/BO)	CO_2 Sqstr Potential (Tcf)	(Gt)	Sqstr Costs ($/t)	Total Costs G $
13	9	Western Gulf	On	Near	2200	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	91	8.3	6.00	49.8	2.6	31.8	84
14	15	Permian Basin	On	Near	2800	35	75%	0%	1.20	0.20	3.38	18.00	22.78	11.60	-11.18	77	7.0	6.00	41.8	2.2	35.2	78
23	19	Gulf Cenozoic OCS	Off	Med	2300	40	75%	0%	0.80	2.00	4.05	18.00	24.85	12.00	-12.85	20	3.4	6.00	20.5	1.1	40.5	44
22	22	N. Alaska	On	Far	2000	25	25%	50%	0.80	3.00	2.70	26.00	32.50	10.80	-21.70	51	2.6	8.67	22.2	1.2	47.3	56
58	29	Anadarko Basin	On	Near	2500	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	10	0.9	6.00	5.5	0.3	31.8	9
33	32	East Texas Basin	On	Near	2300	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	23	2.0	6.00	12.3	0.7	31.8	21
39	35	Louisiana-Mississippi Salt Basin	On	Near	2500	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	18	1.6	6.00	9.8	0.5	31.8	17
21	37	San Joaquin Basin	On	Near	1200	20	0%	75%	0.80	0.20	2.70	30.00	33.70	10.40	-23.30	47	2.3	10.00	23.5	1.2	44.0	55
71	53	Palo Duro Basin	On	Near	1800	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	8	0.7	6.00	4.1	0.2	31.8	7
52	56	Los Angeles Basin	On	Near	1500	30	75%	0%	0.80	0.20	2.70	18.00	21.70	11.20	-10.50	21	1.1	6.00	6.4	0.3	33.1	11
53	64	Bend Arch-Fort Worth Basin	On	Near	2500	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	12	1.1	6.00	6.3	0.3	31.8	11
120	67	San Juan Basin*	On	Near	2000	30	75%	0%	0.80	0.20	2.70	18.00	21.70	11.20	-10.50	4	0.2	6.00	1.1	0.1	33.1	2
97	82	SW Wyoming	On	Near	3000	40	75%	0%	1.20	0.20	3.38	18.00	22.78	12.00	-10.78	2	0.4	6.00	2.3	0.1	33.9	4
63	83	Ventura Basin	On	Near	1600	25	25%	50%	0.80	0.20	2.70	26.00	29.70	10.80	-18.90	11	0.6	8.67	4.9	0.3	41.2	11
50	92	Powder River Basin	On	Near	1300	20	0%	75%	0.80	0.20	2.70	30.00	33.70	10.40	-23.30	14	0.7	10.00	7.1	0.4	44.0	17
68	103	Illinois Basin	On	Near	1500	25	25%	50%	0.80	0.20	2.70	26.00	29.70	10.80	-18.90	11	0.5	8.67	4.7	0.2	41.2	10
77	105	Southern Oklahoma	On	Med	2500	35	75%	0%	0.80	1.00	2.70	18.00	22.50	11.60	-10.90	7	0.6	6.00	3.6	0.2	34.3	6
80	107	Michigan Basin	On	Near	2000	38	75%	0%	0.80	0.20	2.70	18.00	21.70	11.84	-9.86	4	0.5	6.00	3.1	0.2	31.1	5
121	108	Arkoma Basin	On	Med	2500	35	75%	0%	0.80	1.00	2.70	18.00	22.50	11.60	-10.90	2	0.2	6.00	1.0	0.1	34.3	2
96	109	Wyoming Thrust Belt	On	Med	3000	40	75%	0%	1.20	1.00	3.38	18.00	23.58	12.00	-11.58	2	0.4	6.00	2.5	0.1	36.5	5
75	111	Southern Alaska	On/Off	Med	1200	40	75%	0%	1.80	1.50	3.04	18.00	24.34	12.00	-12.34	4	0.6	6.00	3.8	0.2	38.9	8
105	114	Nemaha Uplift	On	Near	2500	30	75%	0%	0.80	0.20	2.70	18.00	21.70	11.20	-10.50	7	0.3	6.00	2.0	0.1	33.1	3
60	116	Big Horn Basin	On	Med	3000	40	75%	0%	1.20	1.00	3.38	18.00	23.58	12.00	-11.58	5	0.9	6.00	5.3	0.3	36.5	10
83	117	Williston Basin (US)	On	Near	2000	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	5	0.5	6.00	3.0	0.2	31.8	5
102	119	Cambridge Arch-C. Kansas Uplift	On	Near	2000	30	75%	0%	0.80	0.20	2.70	18.00	21.70	11.20	-10.50	7	0.3	6.00	2.0	0.1	33.1	4
117	124	Uinta-Piceance Basin	On	Med	1600	30	75%	0%	0.80	0.20	2.70	18.00	21.70	11.20	-10.50	4	0.2	6.00	1.2	0.1	33.1	2
135	125	Rocky Mountain Deformed Belt	On	Near	2500	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	1	0.1	6.00	0.6	0.0	31.8	1
111	131	Cherokee Platform	On	Near	2200	32	75%	0%	0.80	0.20	2.70	18.00	21.70	11.36	-10.34	5	0.3	6.00	1.7	0.1	32.6	3
115	133	Denver Basin	On	Near	1800	35	75%	0%	0.80	0.20	2.70	18.00	21.70	11.60	-10.10	3	0.2	6.00	1.5	0.1	31.8	2
146	134	Sacramento Basin	On	Near	2200	40	75%	0%	0.80	0.20	2.70	18.00	21.70	12.00	-9.70	0	0.1	6.00	0.3	0.0	30.6	1
103	136	Santa Maria Basin	On	Near	1500	23	25%	50%	0.80	0.20	2.70	26.00	29.70	10.64	-19.06	5	0.2	8.67	2.0	0.1	41.6	4
116	147	Wind River Basin	On	Med	3000	40	75%	0%	1.20	1.00	3.38	18.00	23.58	12.00	-11.58	1	0.2	6.00	1.3	0.1	36.5	2
131	151	Sedgwick Basin	On	Near	2200	32	75%	0%	0.80	0.20	2.70	18.00	21.70	11.36	-10.34	2	0.1	6.00	0.7	0.0	32.6	1
		TOTAL 33 Basins														483	39		258	13.6	36.7	500

Figure B-2
CO_2 Sequestration Capacity and Costs in U.S. EOR Projects

C
CASE STUDIES

Field	Operator	hp	EOR Oil Prod. (BOPD)	hp/BOPD	Comment
CO_2-EOR					
Salt Creek	Mobil	57,900	12,000	4.8	Excludes CO_2 compression, which is provided by a third party vendor
Slaughter	Mobil	14,270	2,000	7.1	
E. Bellmont/Aldridge	Henry	11,142	1,700	6.6	
E. Hanford/Hanford	Fasken	6,200	1,100	5.6	
Huntely	Southwest Royalty	4,355	289	15.1	
E. Penwell	Fina	3,050	100	30.5	
Purdey/Bradley	Anadarko	20,000	NA	NA	Production volumes unavailable
		Average:		**12**	
Thermal EOR					
Kern Front	Oxy USA	3,800	5,400	0.7	
Midway Sunset	Nuevo	7,100	6,800	1.0	
Cymric	Nuevo	8,220	8,100	1.0	
Midway Sunset	Aera	121,750	27,500	4.4	
South Bellridge	Aera	26,800	43,660	0.6	
		Average:		**1.56**	

Figure C-1
Horsepower to Barrels of Oil Per Day

CO_2-EOR Case Studies

Case 1.	Salt Creek, Mobil
Case 2.	Slaughter, Mobil
Case 3.	East Pennwell, Fina
Case 4.	East Hanford/Hanford
Case 5.	East Huntley/South Huntley
Case 6.	Purdey/Bradley
Case 7.	Bellmont/Aldridge

CASE 1

FIELD: Salt Creek
STATE: TX
OPERATOR: Mobil
CONTACT: Steven Bearden
PHONE: 806-237-5313

I. Current Status

- **Summary of Operations**
  The Salt Creek CO_2/EOR field produces approximately 12,000 BOPD from 45 CO_2 injection wells and 130 production wells.

- **Major Electricity Consumers**
  Salt Creek field currently uses approximately 32,500 MWhr/month. All equipment runs 24 hr/day, with no redundancy or standby built into the system. Electricity is the major power source, with fluid lift, produced gas compression, and the majority of water injection driven by electricity. CO_2 compression is performed by a third party CO_2 vendor.

Salt Creek Mobil							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
CO_2 Injection	**Supplied by CO_2 Vendor**						
Water Injection (water disposal)	Water Compressor	1,500	11	16,500	16,500	12.31	97,044
	Water Compressor	1,350	3	**Gas Powered**			
Fluid Lift	Beam Pumps	225	130	29,250	29,250	21.82	172,033
Produced Gas Compression	Gas Compressor	5,000	2	10,000	10,000	7.46	58,815
	Gas Compressor	1,350	1	1,350	1,350	1.01	7,940
	Gas Compressor	800	1	800	800	0.60	4,705
			Total:	**57,900**	**57,900**	**43**	**340,537**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  Electricity is used for major operations including fluid lift and water injection/disposal. CO_2 compression is supplied by a third party CO_2 vendor. Electricity has been chosen over natural gas for two reasons:
  1. Air emissions are a substantial concern.
  2. Not enough associated gas is produced to supply the power needs of the field. Natural gas would therefore have to be purchased.

  The current contract with the electric utility stipulates that the field cannot co-generate or buy electricity from another supplier until the end of 2001.

- **Current Electricity Price**
  Confidential, but electricity represents one of the three highest expenses for the operation.

- **Special Notes**
  CO_2 injection is the largest expense for the Salt Creek field. Compression and separation of CO_2 is supplied by a third party vendor. The field currently recycles and returns 92% of its injected CO_2.

II. Future Trends

- There are currently no plans to expand the field.
- Lower electricity prices would have little effect on operations, since electricity is used for most major activities. Mobil would consider converting the gas fired water injection pumps to electric run pumps if electricity prices lowered dramatically.

CASE 2

FIELD: Slaughter
STATE: TX
OPERATOR: Mobil
CONTACT: Forest Collier
PHONE: 915-688-2085

I. Current Status

- **Summary of Operations**
  The Mobil Slaughter CO_2 EOR project produces approximately 2,000 BOPD from 47 CO_2 injection wells and 84 production wells.

- **Major Electricity Consumers**
  According to the field supervisor's estimates, Slaughter field consumes approximately 2,500 MWhr/month. Fluid lift and water disposal are the two main consumers of electricity. CO_2 compression and separation are performed by a third party vendor.

Slaughter Mobil							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
CO_2 Injection	**Supplied by CO_2 Vendor**						
Water Injection (water disposal)[2]	Water Compressor	180	18	3,240	2,430	1.81	14,292
Fluid Lift	Beam Pumps[3]	40	296	11,840	11,840	8.83	69,637
			Total:	**15,080**	**14,270**	**11**	**83,928**

[1] Assumes 24hr/day, 328 days/year
[2] Approximately 75% of the pumps run at any given time. Capacity ranges from 125-250 hp.
[3] Bean pump capacity ranges from 25-70 hp, with an average of 40 hp

- **Electricity vs Gas**
  Electricity is used for major operations including fluid lift and water injection/disposal. CO_2 compression is supplied by a third party CO_2 vendor.

- **Current Electricity Price**
  Confidential, but electricity represents one of the three highest expenses for the operation.

- **Special Notes**
  CO_2 injection is the largest expense for the Slaughter project. Compression and separation of CO_2 is supplied by a third party vendor.

II. Future Trends

- There are minor plans to expand the field, although the affect on electricity consumption is anticipated to be negligible.
- Lower electricity prices would have little effect on operations, since electricity is used for all major activities. Lower prices would directly translate to higher profits.

CASE 3

FIELD: East Penwell
STATE: TX
OPERATOR: Fina
CONTACT: Ed Pittenger
PHONE: 915-688-0607

I. Current Status

- **Summary of Operations**
  The East Pennwell CO_2/EOR field produces approximately 100 BOPD from 13 CO_2 injection wells and 34 production wells.

- **Major Electricity Consumers**

East Penwell Fina Petroleum							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
CO_2 Re-injection[3]	CO_2 Compressor	150	1	150	150	0.11	882
Water Injection (water disposal)	Water Compressor (PD Pumps)	800	1	800	800	0.60	4,705
Fluid Lift	Rod Pump Wells	30	70	2,100	2,100	1.57	12,351
			Total:	**3,050**	**3,050**	**2**	**17,938**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  Electricity is used for compression, lift, and injection due to impurities in the associated gas.

- **Current Electricity Price**
  Confidential

II. Future Trends

- There are no plans to expand the field
- Lower electricity prices would have little effect on operations, since electricity is used for all major activities. Lower energy costs would extend the life of the project however.
- No new technologies affecting the amount of electricity consumed are being considered.

CASE 4

FIELD: Hanford and East Hanford
STATE: TX
OPERATOR: Fasken Oil
CONTACT: Jimmy Davis
PHONE: 915-687-1777

I. Current Status

- **Summary of Operations**
  The Hanford CO_2/EOR fields produce approximately 1,100 BOPD from 30 CO_2 injection wells and 100 production wells.

- **Major Electricity Consumers**

Hanford/East Hanford, West Texas Fasken Oil							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
$C0_2$ Compression	Compressors	40	3	120	120	0.09	706
Water Injection (water disposal)	Possitive Displacement	120	9	1,080	1,080	0.81	6,352
Fluid Lift	Beam Pumps	50	100	5,000	5,000	3.73	29,407
			Total:	**6,200**	**6,200**	**5**	**36,465**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  It has been more economic to use electricity over associated due to the following reasons: 1) small size of the project; 2) opportunity cost of burning associated gas rather than selling it; 3) diminishing gas/oil ratio of the field.

- **Current Electricity Price**
  $0.055/kWh

- **Special Notes**
  CO_2 is supplied by the Amerada Hess Pipeline.

II. Future Trends

- No plans to expand the field
- Fasken predicts that lower electricity costs would prolong the life of the field by making marginal to sub-marginal wells more attractive.
- No new technologies that would alter electricity consumption are foreseen.

CASE 5

FIELD: E. Huntley/S. Huntley
STATE: TX
OPERATOR: Southwest Royalty
CONTACT: Nelson Patton
PHONE: 915-686-9927

I. Current Status

- **Summary of Operations**
  The Huntley CO_2/EOR fields produce approximately 289 BOPD from 23 CO_2 injection wells and 69 production wells.

- **Major Electricity Consumers**

E. Huntley/S. Huntley Southwest Royalty							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
East Bellmont (Sims)							
CO_2 Re-injection[3]	Compressor	2,000	1	**GAS POWERED**			
	Compressor	185	1	**GAS POWERED**			
Water Injection (water disposal)	Water Compressor	125	2	250	250	0.19	1,470
Fluid Lift	Rod Pump Wells	40	73	2,920	2,920	2.18	17,174
			Total:	**3,170**	**3,170**	**2**	**18,644**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  Electricity is used for water injection and fluid lift; natural gas is used for CO_2 compression.

- **Current Electricity Price**
  Confidential

- **Special Notes**
  1. Southwest Royalty purchases natural gas for compression rather than burning associated gas due to impurities in the associated gas.
  2. All of the injected CO_2 used in the project is recycled, none of it is purchased. This saves Southwest Royalty \$250k/month in CO_2 expense.

II. Future Trends

- There are active plans to drill more production wells to expand the project. These plans are driven by economics and therefore no firm estimate was given, but the field could conceivably expand by 30%.

- Southwest Royalty might consider switching from gas to electricity for compression if electricity prices were to come down and gas prices were to go up. Price changes would have to be extreme for the 2,000 hp compressor to be converted economically. The 800 hp compressor could be converted economically with less drastic price changes.
- No new technologies affecting the amount of electricity consumed are foreseen, but the producer is examining strategies, such as running fluid lift pumps during non-peak hours, to cut back on electricity.

CASE 6

FIELD: Purdy & Bradley
STATE: OK
OPERATOR: Anadarko Petroleum
CONTACT: Alan O'Donnell/Tom Rushing
PHONE: 281-874-3389

I. Current Status

- **Summary of Operations**
  The Purdey and Bradley CO_2/EOR fields produce from 80 production wells. Volumes of produced oil and number of injector wells are not available.

- **Major Electricity Consumers**
  Compression from the CO_2 source to the injection well head and water lift consume the majority of electricity used in these two fields. Gas turbines are used for other operational aspects on-site, including re-injection of recovered CO_2.

Purdy/Bradley Fields, Central OK Anadarko Petroleum							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
$C0_2$ Compression[2] (plant to injectionwell)	Electric Compressor	4,000	3	12,000	8,000	5.97	47,052
CO_2 Re-Injection	**Gas Powered**						
Water Injection (water disposal)	**NA**						
Fluid Lift[3]	Submersible Pumps	150	80	12,000	12,000	8.95	70,578
			Total:	**24,000**	**20,000**	**15**	**117,629**

[1] Assumes 24hr/day, 328 days/year
[2] Two out of three are used at any one time
[3] 150 hp capacity is estimated

- **Electricity vs Gas**
  Along the 120 mile pipeline from the CO_2 source to the injection well head, electricity is being used for compression due to the lack of a gas supply. Electric powered submersible pumps are used on-site for water lift in production wells.

  Gas is being used in lieu of electricity for compression of recycled CO_2 for the following reasons:
  1. Terms of the property lease allow associated gas to be used on-site for free.
  2. Emissions concerns are a minor, non-critical factor.

- **Current Electricity Price**
  Unknown, but the current electricity costs for both projects are approximately $500k/month (40% piping CO_2, 40% Purdy fluid lift, 20% Bradley fluid lift)

- **Special Notes**
  1. Anadarko has an exclusive contract with a monopoly CO_2 supplier (fertilizer plant) 120 miles away.
  2. Natural gas in the form of associated gas is free (excluding the opportunity cost of not selling the associated gas on the open market) and is abundantly available.

II. Future Trends

- Although the fields are expected to expand over the next several years, electricity consumption is expected to remain the same or decline slightly. It is anticipated that field expansions will be countered by abandonment of other portions of the fields, yielding a zero net impact on electricity consumption.
- Consideration is being given to using associated gas to fire low wattage gas turbine generators on-site to generate electricity. Whether or not this occurs will depend upon the market price for gas, i.e. the opportunity cost of burning associated gas on-site rather than selling it on the open market.
- Electricity represents the single largest cost to Anadarko at these two fields. The electricity costs to compress and pipe CO_2 from the source plant to the injection well head exceeds the original price of the CO_2. Anadarko calculates a per barrel of fluid processed cost of electricity, rather than computing the electricity consumption of each individual stage of production. Anadarko anticipates that lower future electricity costs would have two affects: 1) per barrel electricity costs would lower, increasing profits; 2) marginal wells that are currently shut in after reaching a 1% oil cut would become economic to lower percentage oil cuts, allowing them to be produced longer. In addition, lower electricity prices might make on-site gas turbine generation less economically attractive. All of these effects would increase the overall demand for electricity.

CASE 7

FIELD: East Bellmont/Aldridge
STATE: OK
OPERATOR: Henry Petroleum
CONTACT: Keith Maberry
PHONE: 915-694-3000

I. Current Status

- **Summary of Operations**
  The East Bellmont/Aldridge CO_2/EOR fields produce approximately 1,700 BOPD from 16 CO_2 injection wells and 225 production wells.

- **Major Electricity Consumers**

East Bellmont and Aldridge, OK Henry Petroleum							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
East Bellmont (Sims)							
Gas Compression[2] (wellhead to pipeline)	Electric Compressor	2,000	2	4,000	1,833	1.37	10,783
	Electric Compressor	1,500	1	1,500	1,833	1.37	10,783
CO_2 Injection[3]	CO_2 Pumps	750	2	1,500	750	0.56	4,411
Water Injection (water disposal)	Water Compressor (PD Pumps)	250	3	750	750	0.56	4,411
	Turbine Injectors	150	1	150	150	0.11	882
	Turbine Injectors	200	1	200	200	0.15	1,176
Fluid Lift	Submersible Pumps	150	20	3,000	3,000	2.24	17,644
	Rod Pump Wells	75	33	2,475	2,475	1.85	14,557
Aldridge							
Fluid Lift	Rod Pump Wells	30	5	150	150	0.11	882
			Total:	**13,725**	**11,142**	**8**	**65,529**

[1] Assumes 24hr/day, 328 days/year
[2] Two out of three are used at any one time
[3] One out of two are used at any one time

- **Electricity vs Gas**
  Electricity has been the clear alternative over gas for compression in this field due to:
  1. High gas prices ($2.30-2.60/Mcf with a high in the last three years of over $3.00/Mcf) due to a monopoly supplier.
  2. Higher maintenance cost with gas compressors
  3. Emissions concerns (minor factor)

- **Current Electricity Price**
  Unknown

- **Special Notes**
  1. CO_2 supply is falling. Supply shortage is due to a fixed, exclusive contract with a monopoly supplier.
  2. Monopoly supplier of natural gas.

II. Future Trends

- Electricity consumption is expected to remain the same or decline slightly over the next 15-20 years.
- Since all major power consumption is currently met by electricity, no change in operations is expected if electricity prices were to come down.
- No new technology affecting the amount of electricity consumed is foreseen.

Thermal EOR Case Studies

Case 1. Kern Front, Oxy U.S.A.

Case 2. Midway Sunset, Nuevo Energy

Case 3 Cymric, Nuevo Energy

Case 4. Midway Sunset, Aera Energy

Case 5. South Bellridge, Aera Energy

CASE 1

FIELD: Kern Front
STATE: CA
OPERATOR: Oxy U.S.A.
CONTACT: Kevin McDonnell
PHONE: 661-392-7181

I. Current Status

- **Summary of Operations**
  The Oxy Kern Front thermal EOR project produces approximately 5,400 BOPD from 28 steam injection wells and 140 production wells. Approximately 170 MW of electricity are co-generated on-site.

- **Major Electricity Consumers**
  Oxy purchases co-generated steam and electricity from a third party vendor operating on-site. The major electricity consumers are fluid lift and water disposal.

Kern Front Oxy USA							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
Fluid Lift	Rod Pump	25	140	3,500	3,500	2.61	20,585
Water Injection (Disposal)	Cam Pump	100	3	300	300	0.22	1,764
			Total:	**3,800**	**3,800**	**3**	**22,350**
Co-Generation							
Operation	**Units**	**Unit Fuel Requirment (mmcfd)**	**Total Fuel (mmcfd)**	**Unit Steam Generation (lbs/hr)**	**Total Steam Generation (lbs/hour)**	**Unit Capacity (MW)**	**Total Capacity (MW)**
Electricity/Steam Generation	3	11.27	33.81	95,000	285,000	47	141
	1	9.9	9.9	44,000	44,000	48	48
	Total:		**44**		**329,000**		**189**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  Natural gas is used for on-site co-generation of steam and electricity, while co-generated electricity is used for fluid lift and water disposal/injection. Oxy purchases co-generated steam and electricity from Dynasty Power, a third party vendor operating on-site. The electricity and steam co-generated on-site are more than sufficient to supply Oxy's thermal EOR processes. Excess electricity is sold to PG&E, the local power utility. Oxy purchases standby electricity from PG&E when the co-generation plant experiences downtime.

- **Current Electricity Price**
  Electricity represents the highest expense to the operation. Oxy purchases co-generated electricity from Dynasty Power for $0.05/kWh. Standby electricity is purchased from PG&E for $0.33/kWh. In areas of the field not supplied by co-generated electricity, Oxy purchases electricity from PG&E's for $0.12/kWh.

- **Special Notes**
  1. Very little associated gas is produced from the field. Therefore, natural gas is purchased from Southern California Gas.
  2. Steam cannot be generated during periods of co-generation downtime. Therefore, in addition to incurring substantially increased electrical prices, Oxy often experiences slight disruptions in oil production due to a shortage of steam.
  3. PG&E charges approximately three times the normal rate for electricity in areas where it faces competition from co-generation plants.

II. Future Trends

- There are plans to significantly expand thermal EOR operation at the field (although an estimate of the expansion was not provided by the operator). Currently, there is not enough generating capacity to supply steam to an expanded field, so Oxy is examining expansions of its co-generation capabilities.

- Oxy is considering purchasing its own co-generation facilities, and has examined using alternative fuel sources such as biomass in addition to traditional gas fired plants.

CASE 2

FIELD:	Midway Sunset
STATE:	CA
OPERATOR:	Nuevo Energy/Torch Operations
CONTACT:	Tommy Calhoun (Torch Operations)
PHONE:	661-395-5433

I. Current Status

- **Summary of Operations**
  The Nuevo Cymric thermal EOR project produces approximately 6,800 BOPD from 37 steam injection wells and 355 production wells. Approximately 6 MWs of electricity are co-generated on-site. The facility consumes approximately 4,500 MWhr/month.

- **Major Electricity Consumers**
  Nuevo co-generates steam and electricity on-site. In addition to co-generation, approximately 6 boilers are fired to produce steam. The major of electricity is consumed by fluid lift.

Midway Sunset Nuevo Energy							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
Fluid Lift	Rod Pump	20	355	7,100	7,100	5.30	41,758
			Total:	**7,100**	**7,100**	**5**	**41,758**
Co-Generation							
Operation	**Units**	**Unit Fuel Requirment (mmcfd)**	**Total Fuel (mmcfd)**	**Unit Steam Generation (lbs/hr)**	**Total Steam Generation (lbs/hour)**	**Unit Capacity (MW)**	**Total Capacity (MW)**
Electricity/Steam Generation	1	4	4	101,000	101,000	6	6
Total:			**4**		**101,000**		**6**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  Natural gas is used for on-site co-generation of steam and electricity, and the production of steam. Co-generated and purchased electricity is used for fluid lift. Depending upon electricity supply and demand at any given time, power may be purchased from or sold to the local utility. Net, approximately 25% of Nuevo's electricity is supplied by the local utility.

- **Current Electricity Price**
  Confidential. Electricity prices range dramatically, depending upon the arrangement with the local utility. Make-up electricity (25% of demand) purchased from the utility is costs twice as much as co-generated electricity. Standby electricity costs eight to ten times as much as co-generated electricity.

II. Future Trends

- Nuevo plans to expand the operation by approximately 20% (between Midway Sunset and Cymric). As the field expands, Nuevo plans to examine alternatives to purchasing power from the local utility. This may including installing more co-generation units when the demand becomes sufficient to warrant the capital expenditure.

CASE 3

FIELD: Cymric
STATE: CA
OPERATOR: Nuevo Energy/Torch Operations
CONTACT: Tommy Calhoun (Torch Operations)
PHONE: 661-395-5433

I. Current Status

- **Summary of Operations**
  The Nuevo Cymric thermal EOR project produces approximately 8,100 BOPD from 53 steam injection wells and 411 production wells. Approximately 3.8 MWs of electricity are co-generated on-site. The facility consumes approximately 4,500 MWhr/month.

- **Major Electricity Consumers**
  Nuevo co-generates steam and electricity on-site. In addition to co-generation, approximately 12 boilers are fired to produce steam. The major of electricity is consumed by fluid lift.

Cymric Nuevo Energy							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
Fluid Lift	Rod Pump	20	411	8,220	8,220	6.13	48,346
			Total:	**8,220**	**8,220**	**6**	**48,346**
			Co-Generation				
Operation	**Units**	**Unit Fuel Requirment (mmcfd)**	**Total Fuel (mmcfd)**	**Unit Steam Generation (lbs/hr)**	**Total Steam Generation (lbs/hour)**	**Unit Capacity (MW)**	**Total Capacity (MW)**
Electricity/Steam Generation	1	2	2.0	51,000	51,000	3.8	3.8
	Total:		**2.0**		**51,000**		**3.8**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  Natural gas is used for on-site co-generation of steam and electricity, and the production of steam. Co-generated and purchased electricity is used for fluid lift. Depending upon electricity supply and demand at any given time, power may be purchased or sold from the local utility. Net, approximately 25% of Nuevo's electricity is supplied by the local utility.

- **Current Electricity Price**
  Confidential. Electricity prices range dramatically, depending upon the arrangement with the local utility. Make-up electricity (25% of demand) purchased from the utility is costs twice as much as co-generated electricity. Standby electricity costs eight to ten times as much as co-generated electricity.

II. Future Trends

- Nuevo plans to expand the field by approximately 20% (between Midway Sunset and Cymric). As the field expands, Nuevo plans to examine alternatives to purchasing power from the local utility. This may including installing more co-generation units when the demand becomes sufficient to warrant the capital expenditure.

CASE 4

FIELD: Midway Sunset
STATE: CA
OPERATOR: Aera
CONTACT: Ed Neilands
PHONE: 661-665-5341

I. Current Status

- **Summary of Operations**
  The Aera Midway Sunset thermal EOR project produces approximately 27,500 BOPD from 107 steam injection wells and 1,525 production wells. Approximately 4 MWs, or 50% of its electricity consumption, are co-generated on-site.

- **Major Electricity Consumers**
  Aera co-generates sufficient steam and electricity on-site to supply half of its power needs. The remaining electricity is purchased from the local utility. The major electricity consumers are fluid lift and water disposal.

Midway Sunset Aera							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
Fluid Lift	Rod Pump	30	1,525	45,750	45,750	34.13	269,077
Water Injection (Disposal)	Central Facility	2,000	20	40,000	40,000	29.84	235,259
	Individual Injection Wells	120	300	36,000	36,000	26.86	211,733
			Total:	**121,750**	**121,750**	**91**	**716,068**
Co-Generation							
Operation	**Units**	**Unit Fuel Requirment (mmcfd)**	**Total Fuel (mmcfd)**	**Unit Steam Generation (lbs/hr)**	**Total Steam Generation (lbs/hour)**	**Unit Capacity (MW)**	**Total Capacity (MW)**
Electricity/Steam Generation	1	4.8	4.8	25,000	25,000	4	4
	Total:		**4.8**		**25,000**		**4**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  1. Natural gas is used for on-site co-generation of steam and electricity, while co-generated electricity, and purchased electricity, is used for fluid lift and water disposal/injection. Aera purchases standby electricity additional electricity from the utility.
  2. Electricity represents the fourth highest expense to the operation. Standby electricity and electricity to meet demand is purchased from the local utility $0.043-$0.18/kWh. Electricity can be co-generated for less than $0.043/kWh.

- **Special Notes**
  1. Very little associated gas is produced from the field. Therefore, natural gas is purchased for co-generation.
  2. The local utility charges approximately four to five times the normal rate for electricity in areas where it faces competition from co-generation plants.
  3. Air emissions are a significant factor in determining the mix of power sources.

II. Future Trends

- Aera would consider purchasing all of its power rather than co-generating if electricity prices were to decline substantially.

CASE 5

FIELD: South Bellridge
STATE: CA
OPERATOR: Aera
CONTACT: Ed Neilands
PHONE: 661-665-5341

I. Current Status

- **Summary of Operations**
  The Aera South Bellridge thermal EOR project produces approximately 43,660 BOPD from 263 steam injection wells and 560 production wells. Approximately 69 MWs of electricity are co-generated on-site.

- **Major Electricity Consumers**
  Aera co-generates sufficient steam and electricity on-site to supply all of its power needs. The major electricity consumers are fluid lift and water disposal.

South Bellridge Aera							
Operation	**Equipment**	**HP Capacity (hp)**	**Units**	**Cum HP Capacity (hp)**	**Adj. HP Capacity (hp)**	**Adj. MW Capacity (mw)**	**Adj. MW Usage (mwh/yr)[1]**
Fluid Lift	Rod Pump	30	560	16,800	16,800	12.53	98,809
Water Injection (Disposal)	Central Facility	2,000	5	10,000	10,000	7.46	58,815
			Total:	**26,800**	**26,800**	**20**	**157,623**
Co-Generation							
Operation	**Units**	**Unit Fuel Requirment (mmcfd)**	**Total Fuel (mmcfd)**	**Unit Steam Generation (lbs/hr)**	**Total Steam Generation (lbs/hour)**	**Unit Capacity (MW)**	**Total Capacity (MW)**
Electricity/Steam Generation	1	63	63	300,000	300,000	65	65
	1	6	6	175,000	175,000	9.6	10
	Total:		**69**		**475,000**		**75**

[1] Assumes 24hr/day, 328 days/year

- **Electricity vs Gas**
  Natural gas is used for on-site co-generation of steam and electricity, while co-generated electricity is used for fluid lift and water disposal/injection. The electricity and steam co-generated on-site are more than sufficient to supply Aera's thermal EOR processes. Excess electricity is sold to the local power utility. Aera purchases standby electricity from the utility when the co-generation plant experiences downtime.

- **Current Electricity Price**
  Electricity represents the fourth highest expense to the operation. Standby electricity is purchased from PG&E for approximately $0.20/kWh. Electricity can be co-generated for less than $0.043/kWh.

- **Special Notes**
  1. Very little associated gas is produced from the field. Therefore, natural gas is purchased for co-generation.
  2. The local utility charges approximately four to five times the normal rate for electricity in areas where it faces competition from co-generation plants.
  3. Air emissions are a significant factor in determining the mix of power sources.

II. Future Trends

- Aera would consider purchasing all of its power rather than co-generating if electricity prices were to decline substantially.

Target:

Chemicals, Petroleum and Natural Gas

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