NATIONAL ENERGY TECHNOLOGY LABORATORY

An Assessment of Gate-to-Gate Environmental Life Cycle Performance of Water-Alternating-Gas CO_2-Enhanced Oil Recovery in the Permian Basin

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Disclaimer

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Acronyms and Abbreviations

AEO	Annual Energy Outlook (Energy Information Agency)
API	American Petroleum Institute
bbl	Barrel
Btu	British thermal unit
CCS	Carbon capture and storage
cf	Cubic feet
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2E	Carbon dioxide Equivalent
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
GHG	Greenhouse gas
GOR	Gas Oil Ratio (usually mcf/bbl [surface conditions])
GS	Geologic sequestration
GWP	Global warming potential
HCPV	Hydrocarbon pore volume (subsurface conditions)
HHV	Higher heating value
IISI	International Iron and Steel Institute
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-hour
lb	Pound
LCA	Life cycle assessment
LCI	Life cycle inventory
Mbbl	Thousand barrels
Mcf	Thousand cubic feet

MJ	Megajoule
MMBtu	Million Btu
MMP	Minimum miscibility pressure
MMscf	Million standard cubic feet (surface conditions)
MMscfd	Million standard cubic feet per day (surface conditions)
MMscfy	Million standard cubic feet per year (surface conditions)
MMmt	Million metric tonnes
MPa	Megapascal
MVA	Monitoring, verification, and accounting
MSTB	Thousand standard barrels
MWh	Megawatt-hour
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NGL	Natural gas liquid
NO_X	Nitrogen oxides
OOIP	Original Oil in Place
OSAP	Office of Systems and Planning
PM	Particulate matter
ppm	Parts per million
ppmv	Parts per million by volume
Psi	Pounds per square inch
Psia	Pounds per square inch, absolute
Psig	Pounds per square inch, gauge
RPV	Reservoir pore volume (subsurface conditions)
scf	Standard cubic feet (surface conditions)
scfd	Standard cubic feet per day (surface conditions)
SDW	Saltwater disposal well
SO_X	Sulfur oxides
STB	Standard barrel (surface conditions)
THC	Total hydrocarbons
UF	Utilization factor

UIC	Underground Injection Control
U.S.	United States
USDW	Underground source of drinking water
VMT	Vehicle mile traveled
VOC	Volatile organic compound
WAG	Water-alternating-gas

Executive Summary

Tertiary recovery of crude oil via carbon dioxide (CO_2) flooding, first employed more than thirty years ago in the Permian Basin of West Texas as a niche application, now represents approximately five percent of domestic crude production. In addition to stimulating oil production, CO_2 enhanced oil recovery (CO_2-EOR) also stores a portion of the injected CO_2, with the remaining fraction recovered for use in other EOR operations. This technology has the potential to grow in the future as the market price of crude oil increases and climate policies provide financial incentive for capturing and sequestering CO_2. However, CO_2-EOR operations are relatively energy intensive and have high associated emissions because of the need to produce, process, and re-inject produced CO_2 and brine.

This study estimates that current CO_2-EOR "best practices" (water-alternating-gas [WAG] injection in a typical Permian Basin reservoir) generate greenhouse gas (GHG) emissions of 71 kg CO_2 equivalents (CO_2E) per barrel of oil extracted - a value nearly three times higher than the average GHG emissions for domestic oil extracted in 2005 of 24 kg CO_2e per barrel (NETL, 2009). In this "best practices" case, 53 percent of the total GHG emissions associated with CO_2-EOR activity result from processing of produced gas to separate CO_2 from the flashed light hydrocarbon fraction (glycol dehydration with Ryan-Holmes type distillative separation), while 41 percent of GHG emissions result from CO_2 compression. The processes to separate brine from produced crude and to pump the brine for re-injection each account for less than 3 percent of total GHG emissions.

Table ES-1 summarizes the results of the gate-to-gate life cycle assessment of three CO_2 EOR operational scenarios. Under current "best practices" 2.5 times more CO_2 is injected than in the historical case, and a high CO_2 injection scenario considers performance with 50 percent more CO_2 injected than in "best practices." These results show that the amount of CO_2 stored per barrel of crude oil produced is highest in the "best practices" case and lower in the high CO_2 injection scenario.

Table ES-1 Summary Results for CO_2 Enhanced Oil Recovery Life Cycle Assessment

CO_2-EOR Operational Scenario	Historical	Current Best Practices	High CO_2 Scenario[a]
CO_2 injection duration (single pattern, years)	7	**25**	36
Volume of CO_2 injected as a percent of the hydrocarbon pore volume in the target formation[b]	0.4	**1.0**	1.5
Oil recovery as a percent of original oil in place (OOIP)	12%	**17%**	21%
Percent of injected CO_2 recycled[c]	60%	**71%**	78%
CO_2 stored per barrel of oil produced (kg CO_2/bbl oil)[c]	200	**230**	210
GHG emissions per barrel of oil produced (kg CO_2e/bbl oil)[c]	51	**71**	95

[a] Assumes (1) improved technologies that enable more efficient contact between CO_2 and residual oil and (2) policy incentives for sequestering CO_2

[b] Hydrocarbon pore volume (HCPV) is the pore volume in a reservoir initially filled with oil, and is often used to describe in-formation fluid volumes and discuss normalized performance between reservoirs. HCPV is calculated as $\Sigma A^*h^*\varphi^*(1-Swi)$ where: A = surface area (40 acres), h = pay thickness (76 ft.), φ = porosity (0.11), and Swi = initial oil saturation as fraction (0.8)

[c] Values are average over the duration of the flood.

Results derived from single injection well modeling of a 40 acre 5-spot tapered WAG injection in a typical formation in the Permian basin, using the CO_2 Prophet model.

Figure ES-1 illustrates the relationship between crude oil recovery and average GHG emissions for the three CO_2-EOR scenarios. GHG emissions increase as oil recovery increases from 12 percent in the historical case, to 17 percent in current "best practices," and to 21 percent in the high CO_2 case. This increase is greater between "best practices" and high CO_2 cases (as indicated by a steeper slope) than between historical and current "best practices" scenarios because greater energy is expended to recover less incremental oil as higher volumes of CO_2 are applied, processed, and re-injected.

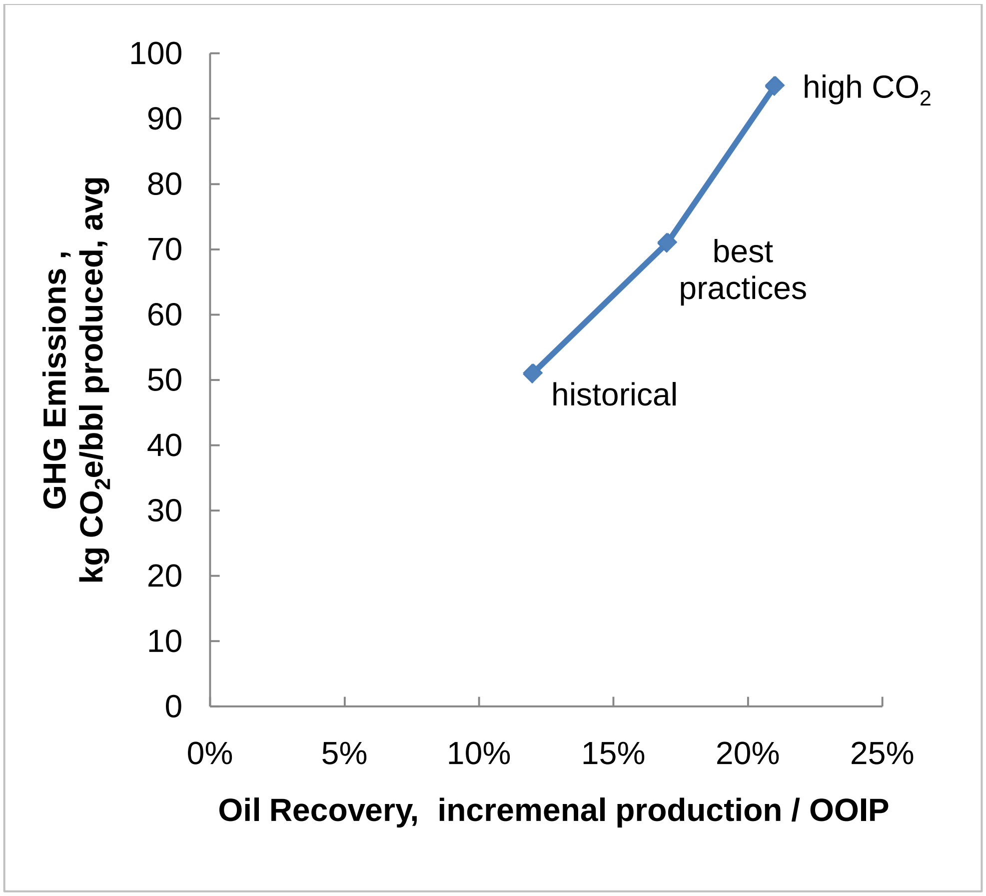
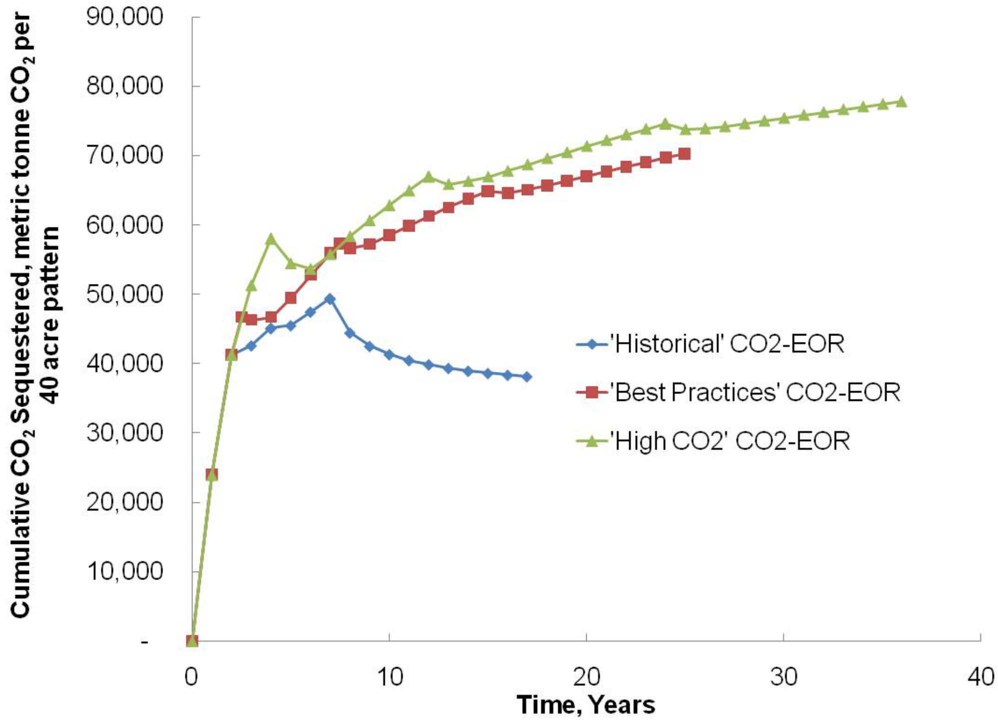


Figure ES-1 Recovery versus GHG Emissions for CO_2-EOR Operational Scenarios

Figure ES-2 reports cumulative CO_2 sequestration and incremental oil production over the life of a CO_2 flood, for the three cases considered; these are pattern-level stream tube model results. The figure shows that most of the CO_2 storage and the highest rates of oil production occur in the early years of the flood. In the historical case, WAG injection is followed by an eleven-year period of water injection to recover remaining mobile oil; as a result of this water injection, CO_2 is displaced from the formation and cumulative CO_2 storage decreases below peak storage in year eight by 23 percent. In contrast, best practices and high CO_2 cases continue the WAG injection until the end of the flood and cumulative storage increases throughout the flood duration in these cases. In practice, the decision to terminate flooding is an economic decision based on crude sale price, operational energy costs, and CO_2 purchase price.



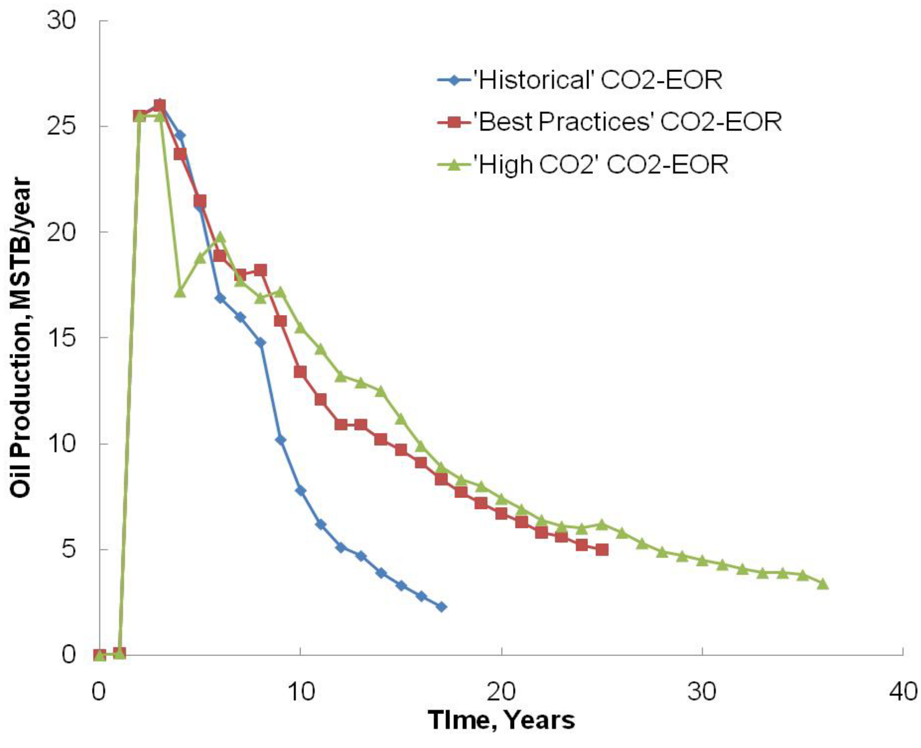


Figure ES-2 CO_2 Retained (Metric Tonne CO_2) in (a) and Incremental Oil Production (MSTB/yr) from (b) a Single 40-Acre, Five-Spot Pattern for Three Operational Scenarios

Future efforts will leverage results of this focused "gate-to-gate" assessment with characterizations of fossil energy extraction and conversion technologies developed by the National Energy Technology Laboratory (NETL) to assess the full "cradle-to-grave" performance of composite energy systems in which CO_2-EOR is used as a geologic sink for CO_2 emissions (e.g., pulverized coal combustion with CO_2 capture and sequestration through CO_2-EOR). Also, the methodology used for estimation of Permian Basin WAG injection will be applied to estimate "gate-to-gate" CO_2-EOR performance of next-generation WAG CO_2-EOR technologies that improve contact between CO_2 and remaining oil, straight CO_2 flooding EOR as is practiced in the Gulf Coast Basin, and other variations on the CO_2-EOR technology paradigm.

1.0 Introduction

1.1 Overview of CO_2-Enhanced Oil Recovery Technology

This study is focused on assessing environmental life cycle performance of domestic, on-shore, CO_2-miscible[1] WAG-type enhanced oil recovery operations. CO_2-miscible operations account for the vast majority of currently producing and planned CO_2-EOR operations in the United States; the Oil & Gas Journal 2010 Worldwide EOR Survey lists 106 producing CO_2-miscible EOR projects (with total enhanced production of approximately 253,000 barrels per day) and only 5 CO_2-immiscible projects (with total enhanced production of approximately 9,300 barrels per day), accounting for less than four percent of all domestic CO_2-EOR (Koottungal, 2009). Figure 1 illustrates that approximately 67 percent of all crude produced in the United States by CO_2-miscible EOR is generated in Texas, and approximately 74 percent of that is produced from the San Andres pay zone, Permian Basin (Koottungal, 2009).

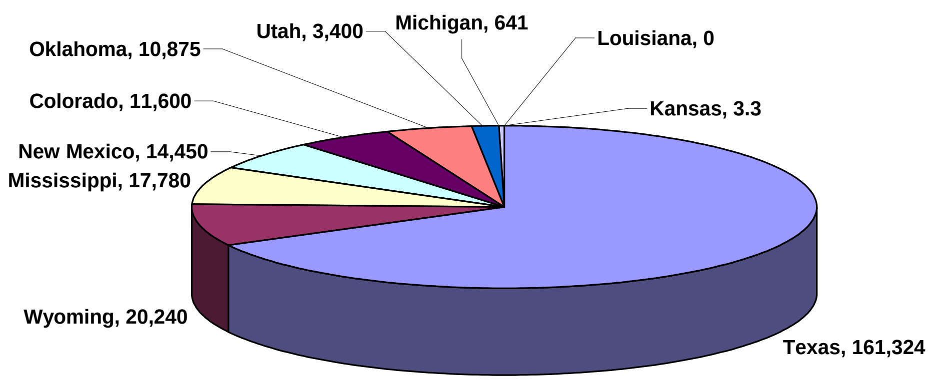


Figure 1-1 Summary of the Distribution of CO_2-EOR Operations in the United States, Reported in Barrels of Crude Oil Produced per Day

Recent publications by the U.S DOE NETL indicate that significant potential remains for domestic incremental oil production from tertiary CO_2-flood EOR, with an estimated 45.0 billion barrels of additional stranded oil accessible using current CO_2-EOR "best practices," and a potential 64.4 billion barrels accessible using "next generation" EOR technology and practices. In addition to this estimated total incremental production, the NETL studies report that implementation of these technologies has the potential to sequester significant quantities of CO_2 in these reservoirs: 12,451 million metric tonnes using "best practices" and 14,477 million metric tonnes using "next generation" technology options.

[1] "Miscibility" refers to the property of two fluids to form a single homogeneous phase when mixed in any proportion. Miscibility of two fluids is observed in a given range of temperatures and pressures, outside of which they will, at some proportion, exist as two discrete phases.

1.2 Purpose of Study

This study is intended to provide a detailed, bottom-up life cycle inventory of CO_2-flood enhanced oil recovery (CO_2-EOR) operations, considering all associated significant infrastructure elements, process flows, and activities. The assessment is based on an inventory of all phases of activity for model CO_2-EOR operations, and all of the environmental burdens attributed to each phase of CO_2-EOR activity are summed to estimate a total environmental burden of producing crude oil through CO_2-EOR. Natural gas and natural gas liquid co-products are accounted for by applying a credit equivalent to the upstream emissions profile of a product with equivalent function that is available to the market from another source.

In addition, this study is intended to develop an improved understanding of CO_2-EOR performance with respect to oil production, geologic CO_2 storage potential, and environmental performance under different operational scenarios. Results of this “gate-to-gate” analysis can be integrated with characterizations of other unit processes (e.g., petroleum refinery or integrated gasification combined cycle inventories) to generate full “cradle-to-grave” assessments of various energy conversion pathways.

Whether used as a stand-alone tool for assessment of CO_2-EOR performance or integrated into a larger, cradle-to-grave life cycle assessment (LCA) of fossil energy conversion pathways, the product developed as a result of this effort is intended to inform policy decision makers, industry representatives, and managers of research programs about environmental costs and benefits associated with application of this technology. This effort has also been useful to identify areas where available data are insufficient to accurately estimate related resource demands or environmental emissions and focus future data collection efforts.

1.3 Scope of Assessment

The scope of this assessment focused on characterizing the environmental performance of all phases of CO_2-EOR, including (1) site evaluation and characterization, (2) facility design and construction, (3) facility startup and operation, (4) facility closure and decomissioning, and (5) monitoring, verification, and assessment of CO_2 storage permanence. To the extent practicable, all significant material and energy flows have been considered for primary activities associated with implementation of tertiary CO_2-EOR at a reservoir with prior primary oil production, and secondary water flood EOR activity. As such, many of the infrastructure elements and activities that would be associated with greenfield development of oil production facilities are assumed to be pre-existing. Justification is provided throughout for all such modeling assumptions.

2.0 Life Cycle Assessment Methodology

Factors considered in establishing appropriate scope and goals for this assessment include (1) establishing the purpose of conducting the study and its intended audience and application; (2) defining the systems being evaluated; (3) identifying the common function and functional unit; (4) defining an appropriate system boundary; (5) summarizing allocation procedures; (6) identifying data requirements (type and quality); (7) summarizing the modeling assumptions, value choices, and optional elements; (8) acknowledging the study limitations, and (9) summarizing quality assurance and review procedures.

Table 2-1 Life Cycle Goal and Scope Definition for CO_2-EOR Gate-to-Gate Environmental Life Cycle Assessment

General Question	Specific Goal
Study purpose	To develop life cycle inventory of CO_2-flood enhanced oil recovery (CO_2-EOR) operations and use that inventory to develop analysis of environmental performance of this CO_2 management alternative
Intended audience	Life cycle practitioners interested in evaluating environmental performance of CO_2-EOR potential as applied to storage of anthropogenic CO_2 and stimulation of incremental oil production
Intended level of assessment detail	This LCA was developed to meet Level II (standard) level of detail per the three-tiered scale defined in established NETL LCA guidelines
Intended application	This LCA is intended for use to allow relative comparison of gate-to-gate environmental performance of different CO_2-EOR operational scenarios, and for integration into full cradle-to-grave life-cycle analyses associated with CO_2-producing energy conversion processes

Table 2-2 Summary of Life Cycle Boundary and Representativeness of CO_2-EOR Life Cycle Assessment

Life Cycle Boundary	Gate-to-gate (receipt of purchased CO_2 thru crude oil delivery to sales pipeline)
Temporal Representation	30 years of CO_2-EOR active operations to sequester CO_2 from one industrial-scale anthropogenic CO_2 source
Technological Representation	Tertiary, miscible, CO_2 water alternating gas-type EOR flood
Geographical Representation	Typical Permian Basin (West Texas) reservoir properties assumed
Impact Assessment Methodology	Global Warming Potential, IPCC 2007, 100-year time-frame
Reporting Metric	Mass of CO_2E emitted per barrel of oil produced
Data Quality Objectives	Process-based ("bottom-up") modeling approach
	Full transparency of modeling approach and data sources
	Accounting for 99% of mass and energy, and accounting for 99% of environmental relevance (see discussion of cut-off criteria limitations)

2.1 Assessment Methodology and Assumptions

2.1.1 Definition of System Boundary

The boundary considered in this study is "gate-to-gate," meaning that the activity being considered is the use of delivered pipeline-quality CO_2 at the EOR project location through delivery of produced crude to a sales point at the lease boundary. Because petroleum is not permitted to enter a pipeline without meeting minimum specifications, any activities, infrastructure, or material requirement associated with upgrading the petroleum-to-pipeline quality are considered to be within the study boundary.

This system boundary is considered to be in line with the stated goal of this study: to develop a more detailed characterization of process energy and material flows and infrastructure requirements associated with CO_2-based enhanced oil recovery. Performance of these operations is independent of the source from which the CO_2 was taken and the distance from which CO_2 is delivered, and these upstream activities are, therefore, excluded from this gate-to-gate analysis.

As is detailed in subsequent sections, CO_2 injection is alternated with water injection in water alternating gas (WAG)–type CO_2-EOR flood. For purposes of this study it is assumed that brine produced from this or adjacent EOR floods serves as the source of water used to stimulate production. As such, it has been assumed that no additional surface/ground water extraction is needed to supply the demand for water created by the WAG injection. Disposal of produced brine in excess of that which is used to supply the WAG will be required. This is discussed in more detail in subsequent sections. Figure 2-1 provides a simplified schematic of the major process elements associated with the CO_2-EOR operation phase and establishes the LCA boundary for this system.

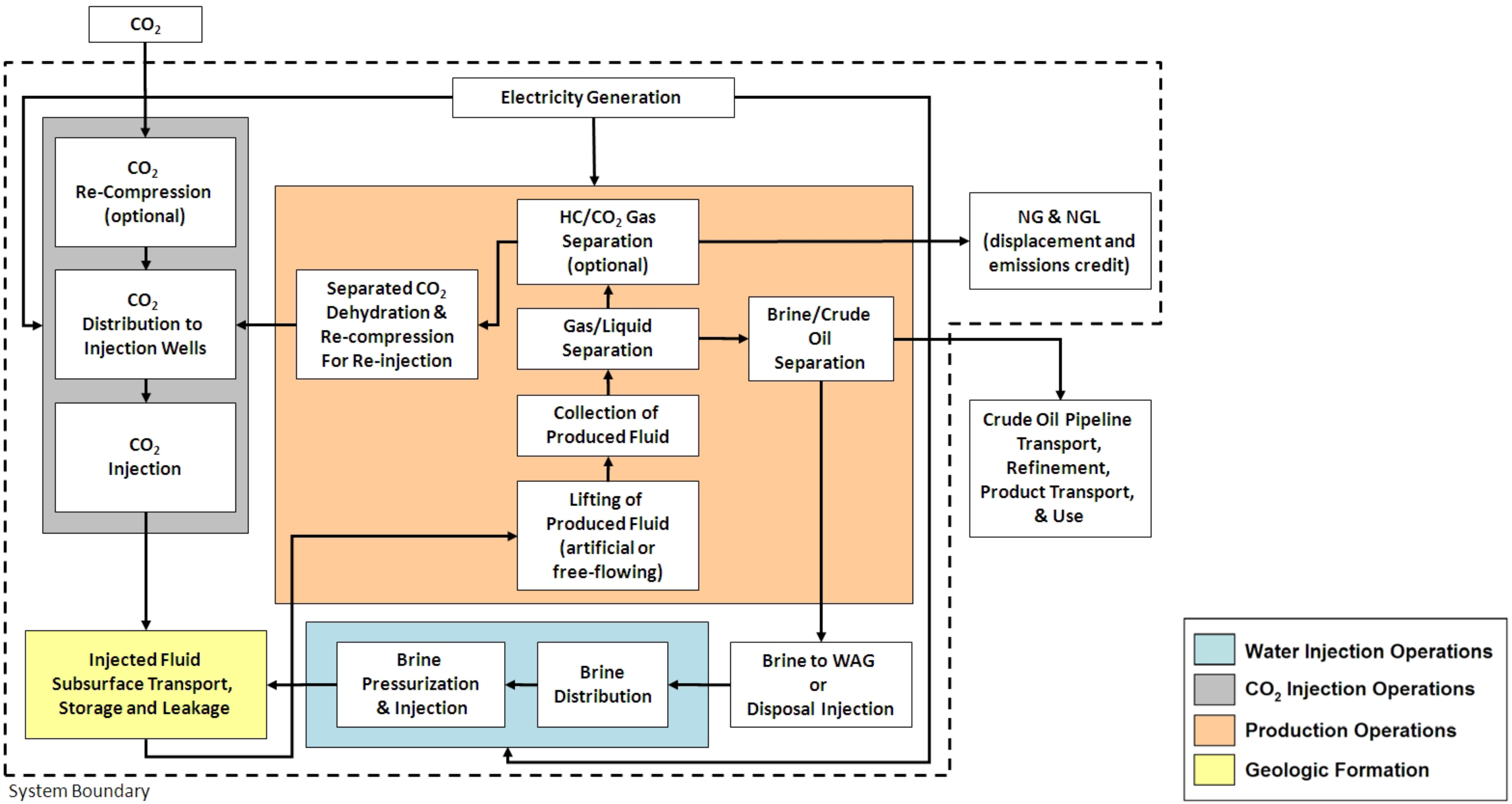


Figure 2-1 Simplified System Boundary for Operation Phase of "Gate-to-Gate" Life Cycle Assessment of CO_2-Based Enhanced Oil Recovery. Dotted line indicates study boundary.

2.1.1.1 Cut-off Criteria for the System Boundary

A common approach employed in the field of LCA to limit the study boundary is to forego the consideration of minor (secondary, tertiary, etc.) activities and flows if their contribution to the overall life cycle falls below a practical limit. Generally such limits are established based on the contribution of those minor elements to the estimated overall incremental change associated with the life cycle of a unit process (for example, limits are commonly set based on accounting for 99 percent of all energy inputs, mass flows, and/or economic activity). However, without fully accounting for all flows and activities associated with a life cycle, it is not possible to identify the appropriate full life cycle value on which threshold "cut off" values are based. As such, establishing cut off criteria can, at best, serve as a guide to the life cycle practitioner who is attempting to determine if a system has been sufficiently described (Johnson, et al., forthcoming).

The decision to include or exclude unit processes or material/energy flows should preferably be based on coherent, transparent justification of reasons for which specific elements have been omitted or included. This justification may be based on consideration of the marginal increase in activity external to the described system, as might be performed through consequential economic input/output-type boundary analysis. However, for the purposes of this study and the relative comparison of different CO_2-EOR operational scenarios, such a boundary analysis is considered to be unnecessary and attributional; a process-based LCA guided by engineering judgment-based cut-off thresholds is considered to be sufficient.

General cut-off threshold guidelines used in developing this LCA include the following: (1) A significant material input or output is considered to be a material that has a mass greater than 0.01 gram (g) per g (one percent, by mass) of the principal product that is produced by the corresponding unit process. (2) A material may also be determined to be significant if it has a relatively high cost (e.g., compared to the cost of the largest, by mass, material input) or has an important environmental relevance (e.g., a high global warming potential [GWP]). (3) A significant energy input is defined as one that contributes more than one percent of the total energy used by the corresponding unit process. As with materials, a significant energy input is also one that has a relatively high cost or has an important environmental relevance.

2.1.1.2 Categorical Exclusions from the System Boundary

Human Activity. There are a number of human activities performed that indirectly contribute to enhanced oil recovery operations (e.g., commuting to and from work, worker water consumption and utilization, etc.) and could be considered to be within the previously-described system boundary. These activities have not been taken into account in the life cycle inventory described herein. ***Catastrophic Releases.*** In contrast to regular or common losses of material or energy that may be inherent to enhanced oil recovery (e.g., material loss during transport or fugitive losses), events occurring with low temporal frequency but with high potential associated emissions and/or environmental impact (e.g., non-routine accidental releases) are excluded from consideration in this study.

2.1.1.3 Treatment of Secondary Material and Energy Inputs

The life cycle inventory of CO_2-EOR includes consideration of all significant material and energy resources contributing to the overall process life cycle, tracking these flows back to the point of extraction from the earth (to "elemental flows" in LCA terminology). Therefore, secondary material and energy inputs such as concrete and steel for facility construction or grid electricity for pump operation have been taken into account in order to develop a complete inventory of all life cycle resource demands. Cradle-to-gate environmental profiles have been taken from other life cycle inventory databases and reports in order to appropriately characterize these secondary materials and energy inputs.

2.1.2 Definition of Functional Unit

ISO 14040: 2006 (E) defines functional unit as the "quantified performance of a product system for use as a reference unit," a definition further clarified in ISO 14041 and ISO/TR 14049:2000 (E). ISO 14041 states that, when defining the functional unit in an LCA, the practitioner must bear in mind the stated goal and scope of the study. Furthermore, the functional unit is used to provide a reference to which input and output data are normalized, requiring that the functional unit be clearly defined and measurable and that the performance characteristics of the product be specified explicitly. The amount of product required to fulfill the function needs to be quantified—a value referred to as the "reference flow." ISO/TR 14049:2000 (E) gives further clarification by outlining the following steps to be taken in defining a functional unit and reference flows: "identifications of functions, selection of functions and definitions of functional unit, and identification of performance of the product and determination of the reference flow."

2.1.3 Identification of Function

The primary function of CO_2-EOR operations is the enhanced recovery of oil from under-producing or non-producing target oil-bearing formation(s), with geologic sequestration of CO_2 considered to be a secondary function. That is to say, construction and operation of CO_2-EOR facilities are driven, at present, by the opportunity to produce salable oil (and, to a lesser extent, other hydrocarbon gasses and liquids) with operations not focused on maximizing CO_2 storage capacity. In contrast, sequestration of CO_2 in brine aquifers would be carried out with the sole function of preventing release of anthropogenic CO_2 to the atmosphere, with no salable product generated from such operations.

The functional unit that has been adopted is sequestration of CO_2 captured from 30 years of operations from one thermoelectric generation facility, and sequestration for a period of 100 years (that CO_2 which has been delivered to the injection site, injected over a period of 30 years, and remains geologically sequestered 100 years after initial injection).

For purposes of this study, CO_2-EOR operations have been scaled to be of sufficient size to accept CO_2 from an existing pulverized coal plant that has been retrofitted with amine-based capture. The plant performance profile is taken from a forthcoming cradle-to-grave life cycle environmental performance and cost analysis (US DOE NETL, 2010) that is based on a previous systems analysis of the carbon capture retrofitting of the Conesville, Illinois, plant, entitled *Carbon Dioxide Capture from Existing Coal-Fired Power Plants* (US DOE NETL, 2007b). This plant has a single 430-MWe subcritical boiler that fires Midwestern bituminous coal, and has been in commercial operation for more than 30 years. From the boiler, flue gas is cooled and sent to an electrostatic precipitator and a 94.9 percent efficient lime-based flue gas desulfurization system. In the case employed for the present study, the existing pulverized coal (PC) -fired plant has been retrofitted with an amine-based CO_2 scrubbing process. After accounting for the auxiliary power parasitic load, the energy requirements of the CCS system, and a seven percent electricity transmission loss, the net power delivered by the plant was calculated as 336 (megawatt of electricity) MWe (US DOE NETL, forthcoming). Performance of this existing PC plant with retrofit capture system is not included within the gate-to-gate life cycle inventory of CO_2-EOR operations. The flowrate of separated CO_2 stream estimated from this study has been used to estimate the amount of CO_2 that would be supplied to CO_2-EOR operations from a moderately sized coal fired facility with post combustion capture, and to estimate the scale of CO_2-EOR activity that would be required to accept this volume of CO_2. In all cases, results have been normalized with respect to barrels of oil produced so that the scale of operations is factored out in final reporting.

Per NETL Quality Guidelines for Energy System Studies (McGurl, et al., 2004), "CO_2, whether being sold for chemical processing or being sequestered, is to be supplied as a liquid and must meet the pipeline specification" as shown in Table 2-3. Boosting or reduction of pressure may be required prior to injection into the receiving formation.

Table 2-3: Specifications for CO_2 supplied to pipeline as reported in NETL Quality Guidelines for Energy System Studies

Parameter	Value
Pressure	152 bar (2,200 psi)
Water Content	233 K (-40 deg F) dew point
N_2	<300 ppmv
O_2	<40 ppmv
Ar	<10 ppmv

Referenced from McGurl, et al. (2004)

2.2 Geographic, Temporal, and Technological Representation

This LCA considers CO_2-EOR activity that is limited to oil fields that have been depleted through primary production and repressured through subsequent secondary water flood enhanced oil recovery prior to initiation of tertiary recovery through CO_2 WAG injection. Because performance is a function of site-specific reservoir properties, fluid characteristics, infrastructure configuration, and injection conditions, it was also necessary to establish these parameters explicitly in order to develop a credible estimate of flood performance. As described in subsequent sections, parameter values were selected that are representative of a typical Permian Basin–type miscible CO_2 flood scenario, although the values do not correspond to a specific real-world EOR reservoir. Evaluation of CO_2-flood EOR performance in target reservoirs with different parameter values would require re-evaluation based on a revised prediction of flood performance. Alternatively, real, detailed, and site-specific flood performance from an existing CO_2-EOR flood could be used to develop an inventory performance evaluation.

Six life cycle stages are considered by NETL in full, "cradle-to-grave" LCAs of energy products: raw material acquisition, raw material transport, energy conversion, product transport, product use, and end-of life management. For the purposes of this assessment of CO_2-EOR, a limited "gate-to-gate" scope is considered, focusing on development of a relatively detailed bottom-up characterization of activity associated with management of CO_2 that is generated as a concentrated stream co-product of the third life cycle stage, energy conversion (e.g., a coal-fired thermoelectric generation facility). Because this study considers a limited scope, the specific process by which the CO_2 is generated is not significant and can be omitted from the comparative assessment of different CO_2-EOR operational scenarios. CO_2-EOR is considered to be a well established and relatively mature technology. CO_2-EOR technology represented includes tapered WAG injection using a 40-acre five-spot pattern configuration with an injection:production well ratio of 1:1. Produced liquid processing is assumed to take place at satellite gathering facilities (aerially distributed tank batteries, separation, and metering points) that process fluid generated from 10 production wells. Gas processing characterization is based on gas stream dehydration and subsequent distillation to separate hydrocarbon from CO_2 stream before recycling to EOR injection wells. Excess brine is disposed of in brine disposal wells. For all unit operations, an assumption has been made that current technology is representative of future operations. However, scenarios have been considered with different applications of those unit operations to represent historical, current best-practices, and high-CO_2 injection CO_2-EOR scenarios, as described in detail in subsequent sections. The assessment assumes relatively large-scale implementation of CO_2-EOR to facilitate the sequestration of large flows of CO_2 that would be generated from capture and sequestration of CO_2 from a single coal-fired thermoelectric generation facility over a 30-year time frame.

2.3 Life Cycle Assessment Indicators and Metrics

A suite of five indicators of life cycle performance have been adopted for characterization of technology or policy options: GHG emissions, criteria air pollutants, water use (withdrawal/consumption), and net energy yield. Following is a brief summary of each.

2.3.1 Greenhouse Gases (GHGs)

Table 2-4 lists the primary GHGs and their corresponding GWP reported in mass of CO_2 equivalents from the Intergovernmental Panel on Climate Change (IPCC) 2007 documents. These values have been adopted for all estimates of global warming potential reported in this study.

Table 2-4 Greenhouse Gases Included in Study Boundary

Emissions to Air	Abbreviation	GWP, CO_2 Equivalents, 100-year time horizon
Carbon Dioxide	CO_2	1
Methane	CH_4	25
Nitrous Oxide	N_2O	298
Sulfur Hexafluoride	SF_6	22,800

2.3.2 Criteria Air Pollutants

Table 2-5 lists six regulated criteria air pollutants as defined in the National Ambient Air Quality Standard by the U.S. Environmental Protection Agency (EPA) in response to the Clean Air Act of 1990. Analysis will include, but will not be limited to, these criteria pollutants.

Table 2-5 Criteria Air Pollutants Included in Study Boundary

Emissions to Air	Abbreviation	Comment
Carbon Monoxide	CO	--
Nitrogen Dioxide/Nitrogen Oxides	NO_2/NO_X	Includes all forms of nitrogen oxides.
Sulfur Dioxide	SO_2	Includes SO_2 and other forms of sulfur oxides.
Ozone, also reported as Volatile Organic Compounds	O_3, VOCs	VOCs combined with NO_x and sunlight form ozone in the atmosphere. Releases of VOCs are reported as a precursor to ozone formation. VOCs are reported as non-methane VOCs to avoid double counting with reported methane emissions.
Particulate Matter	PM	Includes all forms of PM: PM_{10}, $PM_{2.5}$, and unspecified mean aerodynamic diameter.
Lead	Pb	--

2.3.3 **Water Consumption**

In addition to atmospheric emissions, water consumption associated with CO_2-EOR activity is also considered. This life cycle performance metric is reported in units of volume per volume of oil produced and includes consideration of quality of source water, quantity of water used, and/or the source/source type from which the water was extracted. Water consumption is the difference between the amount of water withdrawn for use and the amount of withdrawn water that is returned to the environment after use. Water produced in excess of what is required to maintain EOR operations is considered to be a byproduct of those operations, and activities associated with management of that byproduct are considered as part of the LCA.

2.3.4 **Land Use**

An inventory of land use has been included to quantify land surface area developed or modified as a result of activities being analyzed. Land use is calculated as the total land area on which EOR well patterns are in operation plus land used in gas-processing operations. Off-site land use, such as land use resulting from coal mining operations that supply power plants at which electricity is generated for use in EOR, is not considered in this study. In addition to quantity of surface area, a qualitative description of land type being affected with respect to previous use and ecosystem type being impacted is provided.

2.3.5 **Net Energy Yield**

Net energy yield is the difference between the energy content of an energy product and the total energy/embodied energy demand associated with its production. When considering gate-to-gate CO_2-EOR performance, net energy yield is the energy content of oil and other hydrocarbon products generated minus the energy demand associated with all activities within the EOR facility gate that contribute to generation of those products.

2.4 Allocation Methodology

Allocation procedures follow those set forth in ISO Document 14044 (ISO, 2006), which details a favored hierarchy of allocation methodology giving preference to the most detailed and technically rigorous methodology for which sufficient data are available. When possible, allocation should be avoided by either dividing a process into sub-processes or expanding the system boundaries. In cases where sufficient data or resource limitations do not allow consideration of the expanded system, inputs and outputs should be allocated between the products based on the most appropriate physical/chemical relationships between them. When knowledge of physical or chemical relationships is insufficient to establish an appropriate basis for allocation, other relationships, such as economic value, should be considered. For CO_2-EOR, the primary product is crude oil, and secondary products are natural gas and natural gas liquids. These co-products are generated in relatively small quantities and are accounted for by taking an emissions credit equal to the emissions that would result from producing an equivalent amount (by energy) of these energy products generated through alternative means. Excess brine generated through CO_2-EOR activity is considered to be a byproduct and is treated by system expansion to include brine injection disposal.

2.5 Other Modeling Assumptions

In cases where U.S. EPA AP-42 emissions factors (U.S. EPA, 1995) are reported to be below the detection limit for a particular constituent, it has been assumed that the emission factor for that constituent is half of the reported detection threshold. Therefore, if the emissions factor is reported, for example, to be less than 0.001 lb/MMBtu of fuel consumed, the value used for emissions estimation will be 0.0005 lb/MBtu fuel consumed. Higher heating values used in characterization of mixed hydrocarbon gas are reported in Table 2-6.

Table 2-6 Higher Heating Values for Constituents of Gas Produced from CO_2-EOR Activities

Fuel	HHV[a] Btu/lb
Hydrogen	61,000
Methane	23,900
Ethane	22,323
Propane	21,699
Butane	21,719
pentane	21,071
hexane	20,966

[a] *higher heating value*

Source: Engineering Toolbox (2009)

All electricity demands are characterized in this study using a grid mix profile representative of the Electric Reliability Council of Texas (ERCOT) developed based on the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) 2005 data set (EPA, 2007). This is discussed in more detail in Appendix B. Steel, concrete, natural gas, and natural gas liquids were taken from proprietary life cycle inventory datasets, and those profiles are therefore not listed in this manuscript.

3.0 General Description of CO_2-EOR Technology

The purpose of this study is to develop improved characterizations of facilities/operations associated with CO_2-EOR and brine aquifer sequestration of CO_2 to facilitate comparative assessment of life cycle inventories of these processes. The following is a brief description of major activities and infrastructure elements associated with all phases of these CO_2 sequestration options.

CO_2 flood enhanced oil recovery (CO_2-EOR) is the injection of CO_2 (often injected in alternation with water/brine) into an underground oil-bearing formation for the purpose of stimulating additional production of crude oil. This technique is considered to be a form of tertiary oil recovery, as it is typically employed only after primary extraction and water-flood extraction have been used for oil recovery—typically recovering 20-50 percent of a reservoir's original oil in place (OOIP). Tertiary recovery using CO_2-EOR can be expected to stimulate recovery of an additional 5-20 percent of OOIP (Melzer, 2010).

Begun in the Permian Basin of West Texas, United States, in the early 1970s, there are now on the order of 110 active CO_2 projects producing an average of 250,000 barrels of incremental oil per day, or approximately 5 percent of domestic crude oil production. Cumulative domestic EOR production to date is approximately 1.4 billion barrels and increasing at a rate of 90 mmbbl per year. A recent study reported that the remaining domestic potential for EOR could be as high as 119 billion barrels of additional technically recoverable oil (NETL, 2008).

At present, application and growth of CO_2-EOR in the Permian Basin is limited by the availability of CO_2, with 85 percent of CO_2 used in EOR operations coming from natural sources and 15 percent (20 MMmt per year) coming from industrial and by-product sources (Melzer, 2010). Capture incentives or proposed climate change legislation calling for large-scale capture and sequestration of anthropogenic CO_2 would resolve that limitation and create an opportunity to realize large increases in incremental oil production, and achieve significant geologic sequestration of CO_2 (as much as 13 gigatons of CO_2 storage capability) (NETL, 2008).

3.1 CO_2-EOR Mechanisms and Methodologies

In general, reservoir characteristics required for successful application of any enhanced oil recovery technology include porous, permeable formations of carbonates or sandstones; reservoir throughput (sufficient injectivity); and continuity between wells. In reservoirs in which secondary (water flood) EOR has already been performed, these requisite conditions for tertiary (CO_2-flood) recovery can be assumed.

The primary mechanisms by which oil is recovered through tertiary CO_2 flooding are:

- Generation of miscibility conditions with the oil and CO_2
- Swelling crude oil
- Lowering oil viscosity
- Lowering interfacial tension between oil and CO_2-oil phase in the near-miscible regions

Miscibility refers to the property of fluids to mix in all proportions and form a homogeneous solution; *in situ* miscibility of CO_2 and crude oil is a function of fluid and formation properties such as formation depth, temperature/pressure, and crude oil composition. When CO_2/oil miscibility is achieved in tertiary EOR operations, displacement efficiency of the miscible fluid improves, and the overall flood productivity increases.

In immiscible CO_2 floods, oil swelling and viscosity reduction are the primary mechanisms of enhanced recovery, with oil volume increases of as much as 50 percent resulting in incremental oil production even below the minimum miscibility conditions, from dead-end pores, and viscosity reduction improving relative permeability. While these mechanisms also stimulate productivity over secondary recovery methods, the increased incremental oil production will be lower as compared to CO_2-EOR performed under miscible conditions due to the enhancement of sweep efficiency of miscible flooding. Table 3-1 provides a summary of reservoir and crude oil characteristics recommended for CO_2-EOR operations, as well as approximate °API/formation depth combinations required to achieve minimum miscibility requirements (temperature and pressure are a function of formation depth).

Table 3-1 Technical Screening Guidelines for CO_2 Flooding

Parameter	Recommended	Current Projects Range
Crude Oil		
Gravity,°API	>22	27 to 44
Viscosity, centipoise (cp)	<10	0.3 to 6
Composition	High percentage of intermediates (C5 to C12)	
Reservoir		
Oil Saturation in Water-flooded Swept Zone	>25*[a]	15 to 70
Type of Formation	Thick but relatively thinly bedded sandstone or carbonate unless dipping*	
Permeability	> 1 millidarcy	
Bottom Hole Depth/Temperature	For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP[b], which increase with temperature and for heavier oils. Recommend depths of CO_2 floods of typical Permian Basin oils is as follows:	
	Gravity, °API	**Depth Greater Than (ft)**
CO_2 miscible	>40	2,500
	32 to 39.3	2,800
	28 to 31.9	3,300
	22 to 27.9	4,000
	<22	Fails Miscible CO_2 Screening test
CO_2 immiscible	13 to 21.9	1,800
	<13	Fails CO_2 Screening

[a] *Where noted by an asterisk (*), adapted from Lyons (1996) per comments of Melzer (2010)*
[b] *MMP=minimum miscibility pressure*

3.1.1 Minimum Miscibility Pressure Calculation

Minimum miscibility pressure (MMP) refers to the pressure at which injected CO_2 becomes miscible with the oil in place in the reservoir; it is important to determine this threshold to effectively identify reservoirs that are candidates for miscible CO_2 flooding. A number of correlations have been established to estimate the minimum miscibility pressure (Emera and Sarma 2005); Equation (1) illustrates a simplified Cronquist correlation, which provides a simple means of estimating the miscibility threshold as a function of temperature and oil pentane plus fraction molecular weight (Cronquist, 1978). An expanded form of the Cronquist correlation also takes into account methane and nitrogen gas molar fraction. It is not applied in this study, but may be appropriate for use in future work considering CO_2-EOR operations employing direct CO_2 recycle (without gas processing for CO_2/hydrocarbon separation). This correlation has been applied in earlier NETL studies to establish MMP (U.S. DOE, 2006; U.S. DOE NETL, 2008; U.S. DOE NETL, 2009), and is used again in this work for consistency.

$$MMP = 15.988 * T^{(0.744206 + 0.0011038 * MW\ C5+)} \quad (1)$$

where

MMP = minimum miscibility pressure, pounds per square inch absolute (psia)
T = reservoir temperature, °F
MW C5+ = molecular weight of pentanes and heavier fractions in the reservoir oil

A plot of forecasted MMP as a function of reservoir temperature for a range of molecular weight of the pentanes and heavier fractions from 180 to 340 g/mole) is shown in Figure 3-1.

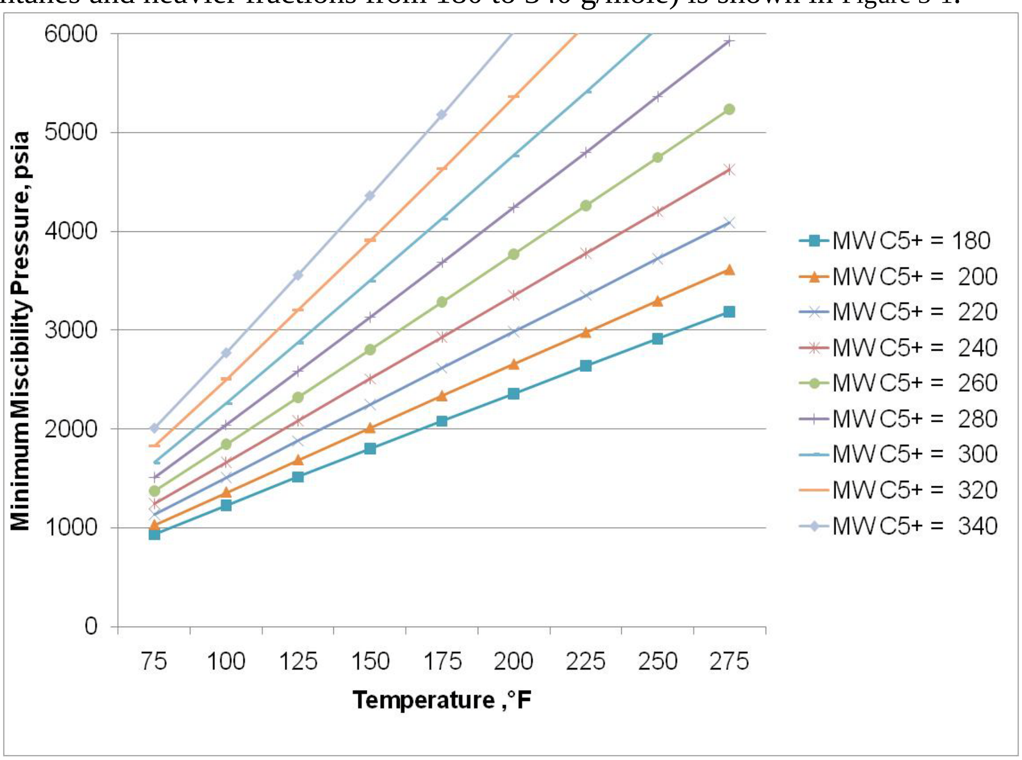
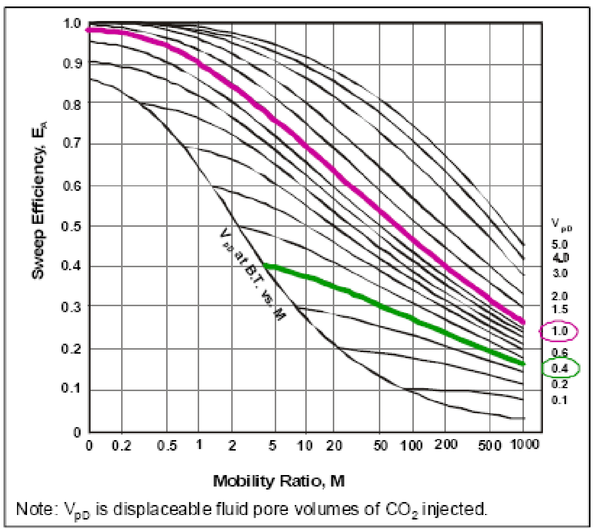


Figure 3-1 Plot of Cronquist Correlation for a Series of C5+ Molecular Weight Values over the Range of Temperatures from 75 to 275 °F

Increased tertiary incremental oil production observed with increasing CO_2 injection and market incentives created by high crude prices have, in recent years, driven operators to inject higher CO_2 hydrocarbon pore volume (HCPV[3]) fractions. In one case, at the Means CO_2-EOR WAG injection in the San Andres Unit, original CO_2 injection targets of 0.55 hydrocarbon pore volume[2] (HCPV) (0.4 HCPV purchased CO_2, and 0.15 HCPV recycled CO_2) were increased to approximately one HCPV. Results of reservoir engineering models that demonstrate increased volumes of CO_2 injection show improved reservoir sweep efficiency (Figure 3-2), which corresponds to higher incremental oil recovery from tertiary EOR (Figure 3-3).

Sweep Efficiency in Miscible Flooding



Source: Claridge, E.L., "Prediction of Recovery in Unstable Miscible Displacement", SPE (April 1972).

Oil Recovery Efficiency vs. CO_2 Injection

Injected CO_2 (HCPV)	Sweep Efficiency (RPV)	Incremental Sweep Efficiency (%)
0.40	0.345	
0.60	0.440	+28%
0.80	0.515	+49%
1.00	0.570	+65%

Source: After Claridge (April 1972) (Mobility Ratio of 25)

Figure 3-2 Example of Oil Recovery Efficiency vs. CO_2 Injection (assumes homogeneous reservoir). Sweep Efficiency in Reservoir Pore Volumes (RVPs) of Miscible CO_2-EOR Flood Increases with Increasing Hydrocarbon Pore Volume (HCPV) Injection.

[2] Hydrocarbon pore volume (HCPV) is the pore volume in a reservoir initially filled with oil, and is often used to describe in-formation fluid volumes and discuss normalized performance between reservoirs. HCPV is calculated as $\Sigma A*h*\varphi*(1-Swi)$, where A is surface area, h is gross pay thickness, φ is porosity as fraction, and Swi is initial water saturation as fraction.

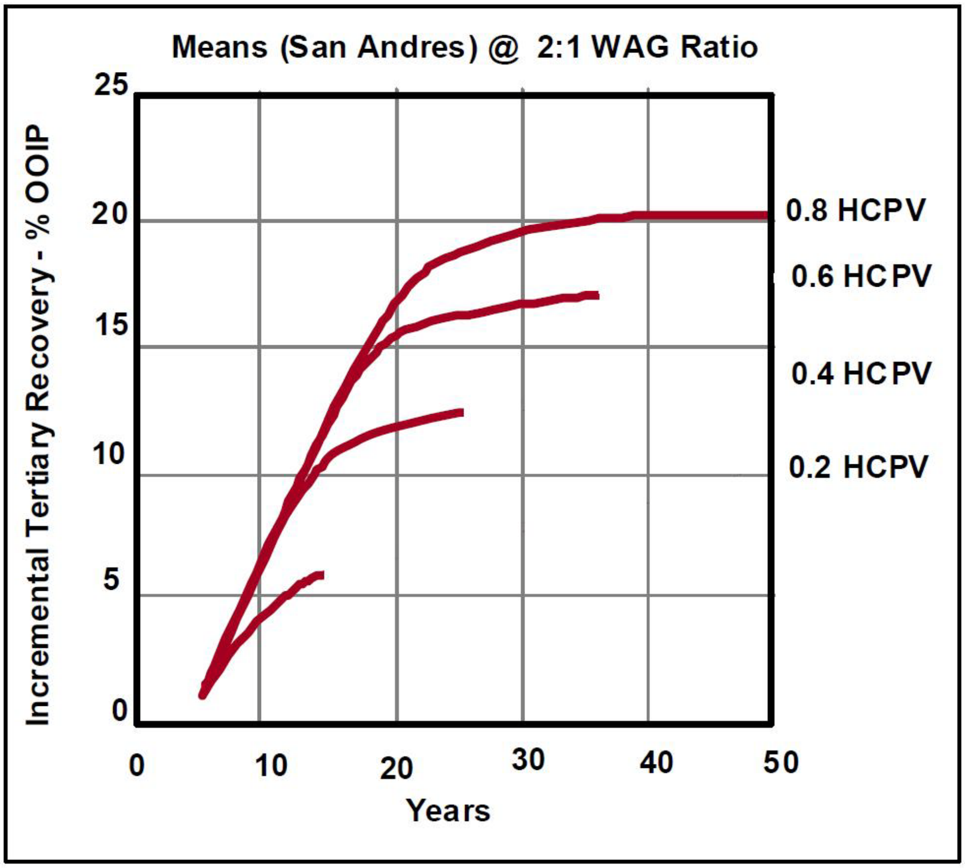


Figure 3-3 Tertiary Oil Recovery Increases with Increasing CO_2, But Also Increases the Required Duration of the CO_2 Injection Before Recovery Drops Off.

3.1.2 **Water Alternating Gas (WAG) Tertiary Injection Scheme**

Viscosity of CO_2 at formation conditions is significantly lower than that of crude oil (CO_2 viscosity at 123 °F was calculated per Crane [1988] to be 0.0162 cp, while the median viscosity of 228 Permian Basin samples from the ARI Big Reservoir Database [2009] is 1.76 cp). The less viscous pressure-driven fluid forms channels through the oil that is present in the formation. As a result of this channeling, a significant quantity of injected fluid can bypass the oil in the formation and "break through" to the production well without contacting formation oil and without stimulating its production. Any subsequently injected CO_2 will also follow previously established channels, causing poor overall sweep efficiency within the reservoir.

One technology that has been developed to address this channeling and breakthrough of low viscosity CO_2 is alternate injection of water as a higher viscosity drive fluid in a water alternating gas (WAG) injection process. In WAG injection, the alternate injection of water (typically brine that has been produced from adjacent EOR patterns) and CO_2 aids in inhibiting the channeling of less viscous CO_2 through the reservoir from injection to production well, thereby increasing CO_2 residence time and improving contact between CO_2 and the oil remaining in the reservoir. Table 3-2 provides a simplified representation of selected injection options: continuous CO_2 injection, continuous CO_2 followed by water sweep, WAG injection followed by water sweep, tapered

WAG followed by water sweep, and WAG followed by hydrocarbon gas injection and water sweep.

Table 3-2 Simplified Representation of CO_2-EOR Fluid Injection Schemes

Injection Type	Injection Increment (time or injection volume)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Continuous CO_2 injection																
Continuous CO_2 followed by water sweep																
WAG injection followed by water sweep																
Tapered WAG followed by water sweep																
WAG followed by HC gas injection and water sweep																

Color key:

CO_2 Injection	
Water Injection	
HC Gas Injection	

Adapted from Jarrell et al. (2002)

3.1.2.1 Advanced Resources International Big Oil Fields Database

The Big Oil Fields Database contains detailed reservoir-specific parameter data for over 2,000 domestic oil reservoirs, accounting for over 70 percent of the anticipated ultimate remaining production in the United States (ARI, 2009). This database has been developed and is maintained by Advanced Resources International, and is licensed for use by the U.S. DOE/National Energy Technology Laboratory. The database contains reservoir-specific data for 34 parameters, including:

- Reservoir depth, temperature, and pressure
- Volumetrically-consistent original oil in-place[3] (OOIP) endowment
- Up-to-date cumulative oil production and remaining oil reserves (“stranded” oil that is targeted by EOR technologies)

[3] Original oil in place (OOIP) refers to the original hydrocarbon content in place in a formation, by volume atstandard surface conditions and not real formation conditions), before initiation of oil production operations. This value is always greater than the technically and economically recoverable oil reserves in a reservoir.

OOIP at standard conditions (sometimes referred to as STOOIP) is defined by the equation:

$$N = \frac{7758\, V_b\, \phi\, (1 - S_w)}{B_{oi}}$$

where N is OIIP in stock tank barrels, V_b is bulk reservoir volume in acre-feet, φ is fraction of bulk reservoir volume that is fluid-filled porosity, S_w is the fraction of fluid-filled porosity that is saturated with water, B_{oi} is the ratio between volume of a unit mass of oil at reservoir conditions (real barrels), and the volume of the same unit mass at surface conditions (stock tank barrels), and *7758* is a conversion factor between acre-feet and stock tank barrels.

- Existing field infrastructure and activities that influence costs of implementing CO_2-EOR (active and shut-in injection and producing wells, and volumes of water injection and production)
- Up-to-date summary of cumulative EOR production, production rate, and estimated remaining CO_2-EOR reserves

The database also contains sub-routines containing logic to screen reservoirs based on parameter data to:

- Determine reservoir suitability for CO_2-miscible flooding
- Ensure volumetric consistency of reported data
- Summarize reservoir miscible and immiscible CO_2-EOR activity and flood volumes

These data were used in the development of several reports for the U.S. DOE on potential for domestic CO_2-EOR technology development, including a series of reports entitled *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery* for domestic resource basins/areas and two technology analysis reports entitled *Storing CO_2 with Enhanced Oil Recovery*, and *Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology*.

3.2 CO_2-EOR as CO_2 Geologic Sequestration Mechanism

In addition to the primary function of CO_2-EOR to stimulate incremental oil production with the benefit of increasing the security of the domestic oil supply, CO_2-EOR may also serve to store anthropogenic CO_2 through geologic sequestration. A set of "next generation" CO_2-EOR techniques and practices have been proposed to accomplish significant geologic storage of CO_2 while stimulating oil recovery beyond that which has historically been observed or can be realized with current best practices. Historical, current best practices, and next-generation CO_2-EOR operational scenarios are described in detail in the following sections. As discussed above, CO_2-EOR operations are, at present, supplied primarily from naturally-occurring reservoirs of CO_2; proposed legislation on emission of greenhouse gasses could dramatically increase the supply of CO_2 from anthropogenic sources available for CO_2-EOR with concomitant sequestration.

3.2.1 Retention vs. Sequestration in CO_2-Flood EOR

Terminology used to discuss the fate of CO_2 used in EOR operations can be somewhat confusing, and warrants discussion. This confusion stems from differences in understanding and use of the word CO_2 "retention." The EPA's Proposed Mandatory Reporting Rule (75 FR 16584 [2009-4-10]) states:

> The objective of EOR operations is not to maximize reservoir CO_2 retention rates, but to maximize oil production and the amount of CO_2 trapped underground would be a function of site specific and operational factors. There are several EOR operations in the Permian Basin of Texas. One study showed that retention rates for eight reservoirs ranged from 38 to 100 percent with an average of 71 percent, but many of these projects are not mature enough to predict final retention (see Suppliers of CO_2 TSD [EPA–HQ–OAR–2008–0508–044]).

While it is true that CO_2-EOR has, traditionally, been concerned with resource production and not maximizing CO_2 retention, and retention rates are often well below 100 percent, the statement implies that the fraction of CO_2 not retained underground is released to the atmosphere. In response to this proposed rule, representatives of the oil and gas industry expressed concern that the term of art "retention" was being used out of context. Several comments to the Proposed Rule responded to call out this issue; for example, a comment from the American Petroleum Institute (API) states:

> The "retention rate" EPA refers to in the Preamble does not adequately capture the fact that EOR is a "closed system." In fact, the report that EPA cites in their discussion of retention rates recognizes this fact and states that, regarding a reservoir with 38% retention, "Essentially 100% of the purchased CO_2 is still in the system. At the end essentially 100% of the fluid will be stored in a reservoir." Additionally, evidence suggests that CO_2 injected via EOR wells in compliance with the UIC regulations does not leak into the surrounding groundwater (Smyth et al, 2008; Wilson and Monea, 2004) let alone the atmosphere (Klusman, 2003; Wilson and Monea, 2004).

The first portion of this quotation states that essentially all of the acquired (purchased) CO_2 is stored geologically, and the second portion refers to studies suggesting that this storage might reasonably be expected to exhibit favorable permanence of storage that will meet geologic sequestration permanence goals. Oil and gas industry representatives have since expressed interest in further clarifying the definition of "retention" as it relates to geologic "sequestration" and providing real-world, inventory-based examples. To contribute to this clarification, definitions of CO_2 "retention" and "sequestration" in CO_2-EOR are provided, and, in lieu of presentation of case study-based evidence, a simplified example is provided.

3.2.1.1 CO_2 Retention in CO_2-EOR Operations

The distinction between CO_2 "retention" and CO_2 "sequestration" is both one of physical system boundary (around which mass balance is performed), and one of temporal extent of activities included. Jarrell and colleagues (2002) defined "retention" to be

> the amount of CO_2 remaining in the reservoir at any given time, which equals the amount of CO_2 injected less the amount of CO_2 produced.

Expressed as a fraction (as in the previously referenced Proposed EPA Rule), this definition could be written as:

$$Retention = \frac{(cumulative\ injection - cumulative\ production) - \ losses}{cumulative\ injection}$$

where injection includes both the newly purchased plus recycled CO_2. To calculate this fraction, units of standard volume or units of mass can be used. CO_2 retention is used in evaluating the efficiency of CO_2 flooding operations. As referenced therein, this term is effectively a cumulative retention definition. Some companies have adopted an instantaneous retention definition, which is simply the ratio of current injected less produced CO_2 to injected CO_2. In both cases, the injected CO_2 is the sum of purchased and recycled CO_2. For purposes of this report, cumulative quantities will be used.

From the operator's perspective, CO_2 retention during CO_2-EOR operations is considered to be a detrimental factor, as it requires purchase of additional CO_2 to accomplish the same total CO_2 cumulative injection per well pattern (and the same oil production per well pattern): more CO_2 retention can correspond to less efficient utilization of purchased CO_2 resource. As defined by industry, "retention" does not consider the disposition of the CO_2 that is not retained in the reservoir. However, it is important to note that CO_2 that is not retained in the flooded area is not emitted to the atmosphere, but only produced from the reservoir (pattern or field) and available for reuse in the same or adjacent CO_2-EOR operations. While the amount of CO_2 "retained" per well pattern may be as low as 38 percent (U.S. EPA, 2009), the amount of purchased CO_2 that is geologically stored through the period of active injection will approach 100 percent (assumes negligible loss in recycling[4]). Furthermore, the term "retention" refers to the storage of CO_2 in the subsurface over the cumulative period of active injection (per pattern or field) at some point during the period of active injection; it does not consider the amount of CO_2 that is permanently sequestered—which considers the amount of retained CO_2 that remains stored in the subsurface at some period *after* completion of active injection. However, the experience in many reservoirs suggests that the two may be very close (Melzer, 2010).

3.2.1.2 CO_2 Sequestration in CO_2-EOR Operations

The definition of geologic CO_2 sequestration given by the U.S. Department of Energy, National Energy Technology Laboratory (NETL) is as follows:

> the placement of CO_2 into a subsurface formation in such a way that it will remain permanently stored.

The U.S. DOE further defines "permanence" as sequestration after 100 years of storage (post-injection), and has set a goal of 99 percent storage permanence. Sequestration is the geologic storage of CO_2 100 years after the completion of active injection. Storage impermanence takes into account the amount of CO_2 lost to the atmosphere both during the period of active injection and through 100 years of post-injection monitoring, verification, and accounting (MVA) of CO_2 storage. For CO_2-EOR, CO_2 sequestration is the amount of gross CO_2 retained through the period of active injection minus losses. Described as a fraction, this is:

$$Sequestration = \frac{(cumulative\ injection - cumulative\ production) - \ losses}{cumulative\ purchase}$$

To calculate this fraction, units of standard volume or units of mass can be used. The term "losses" includes all losses to the atmosphere (storage impermanence) through the period of active injection and for 100 years following completion of active injection, and includes potential CO_2 leakage to the atmosphere through cap rock and compromised wellbores or plugs[5].

[4] CO_2 separation and recycle operations are considered as a "tight" chemical process with significant effort made to minimize venting and fugitive losses from the system, since such losses have associated loss of hydrocarbon and other tightly regulated gases, and would require that additional CO_2 be purchased.

[5] Fugitive losses from gas recycling operations, as well as direct and indirect (e.g., electricity grid mix emissions) will contribute to overall greenhouse gas emissions, but do not impact gross geologic sequestration performance. Such operational emissions are accounted for separately and used to estimate "net sequestration" performance.

In summary, CO_2 that is “retained” in a single pattern is not available for reinjection into the same or adjacent pattern, as it is stored in the subsurface. CO_2 that is not “retained” in one pattern is, therefore, available for reinjection into the same or adjacent patterns. CO_2 that is retained in the subsurface at the end of a period of active injection is geologically stored; that which remains geologically stored 100 years after completion of active injection is considered to be sequestered. In CO_2-EOR operations, nearly 100 percent of the purchased CO_2 will be geologically stored at the end of the period of active injection and, with sufficient permanence of CO_2 storage, at least 99 percent of the stored CO_2 will be sequestered. Retention and sequestration are discussed in relation to results of this study in Section 4.

3.3 Review of Relevant Literature

3.3.1 NETL Characterizations of CO_2-EOR Economic and Technical Potential

Recent studies published by U.S. DOE NETL and prepared by Advanced Resources International, Inc. (NETL, 2008; NETL, 2009) have defined three CO_2-EOR technology implementation scenarios descriptive of past, present, and likely future CO_2-EOR technology application. In those reports these scenarios are referred to as:

- "Historical" CO_2-EOR Flood Practices
- "Best Practices" CO_2-EOR
- "Next Generation" CO_2-EOR

Progression of CO_2-EOR practices have generally trended toward increased total CO_2 injection volumes to achieve increased oil recovery. While, in the past, CO_2-EOR operations took measures to minimize the purchase of CO_2 by applying modest amounts of CO_2 and water sweeping the flood after CO_2 application to maximize CO_2 recovery for reuse, best-practices reservoir management calls for additional CO_2 injection and allowing retained CO_2 to remain in situ without water slug recovery, and the "next-generation" CO_2-EOR operational scenario further increases formation oil production by increasing CO_2 injection, modification of reservoir fluid properties, and modification of injection well pattern. Each of these three CO_2-EOR operational scenarios is described in greater detail below, and details of each operational scenario are summarized in Table 3-3 and Table 3-4.

"Historical" CO_2-EOR. Historically, the amount of CO_2 injected for tertiary oil recovery has been limited by the cost of CO_2 that is purchased for injection. As such, relatively small total injection volumes (as compared with current "best practices" and "next generation" scenarios as defined herein) were used in early CO_2-EOR. In addition, CO_2 contained in the produced fluid was (and still is) separated, recompressed, and reused. Finally, a slug of water is injected into the formation at the end of the CO_2 flood to recover residual CO_2 remaining in the formation, and the recovered CO_2 is transported to an adjacent field for use as tertiary EOR solvent. Following water slug injection for CO_2 recovery, an estimated 2,000-4,000 standard cubic feet (scf) of CO_2 would remain trapped in the target formation for each barrel of incremental oil produced. While some CO_2 remains trapped following historical CO_2-EOR flood, geologic sequestration of CO_2 is not a goal of CO_2-EOR. Rather, the primary function of CO_2 in historical CO_2-EOR was to maximize tertiary production of oil at a minimum purchased CO_2 cost.

For purposes of this study, and in keeping with the definition of historical CO_2-EOR as defined in previous CO_2-EOR studies, total cumulative CO_2 injected over the flood lifetime is assumed to be 40 percent of total hydrocarbon pore volume (HCPV) in the target formation. Following completion of CO_2-EOR WAG injection, it is assumed that one HCPV of brine is injected to recover as much of the injected CO_2 as possible for use at adjacent operations.

"Best Practices" CO_2-EOR Operational Scenario. High prices of crude oil observed in recent years—on July 11, 2008, light crude prices temporarily reached $147.27/bbl on the New York Mercantile Exchange - symbol CL— have led to the injection of higher total volumes of CO_2 to increase incremental oil production. A series of studies sponsored by the U.S. DOE have evaluated the magnitude of CO_2-EOR potential in 10 domestic basins (in 22 states) using best practices CO_2-EOR technology and "best practices."

A follow-on study sponsored by NETL entitled *Storing CO_2 with Enhanced Oil Recovery* (NETL, 2008) built on the series of basin studies, adding an additional 500 reservoirs to the database of domestic CO_2-EOR potential resources, considering a greater variety of oil and CO_2 price scenarios, and addressing, for the first time, the domestic CO_2 storage capacity using a CO_2-EOR "best practices" injection scenario. In these studies, "best practices" CO_2 flood is defined based on a dramatically increased volumetric injection of 1.0 hydrocarbon pore volumes (as compared to 0.4 HCPV total CO_2 injection representative of "historical" CO_2-EOR operations). In addition to the increase in volume of CO_2 injected, the injection schedule representative of "best practices" is significantly modified—using a tapered water alternating gas (WAG) injection process. As with the historical injection scenario, "best practices" CO_2-EOR includes separation of CO_2 from the produced fluid and recycling if for further injection. In contrast to "historical" CO_2-EOR operations, "best practices" assumes that a water slug is not injected at the end of the CO_2 flood, and the injected CO_2 is not recovered.

"Next Generation" CO_2-EOR Operational Scenario. "Next generation" CO_2-EOR comprises a set of technologies and practices that can be used individually or in combination to improve the productivity of a reservoir over that which would be realized with "best practices" CO_2-EOR and/or to increase the total number of reservoirs that meet criteria to be considered as a viable candidate for miscible CO_2-EOR. Technology/operational alternatives considered to represent "next generation" CO_2-EOR include:

1. Increase volume of CO_2 injection to 1.5 HCPV
2. Application of innovative flood design and well placement:
    - Targeted horizontal wells
    - Modified well alignment
    - Injection of physical or chemical diversion materials
    - Infilling (infilling or infill drilling is the practice of drilling wells to decrease well spacing/increase well density) (Fanchi, 2006)
3. Improving the mobility ratio:
    - Polymers in water (polymer addition to water increases the viscosity of the injected aqueous phase, improving mobility ratio and fluid flow patterns of the flood) (Fanchi, 2006)
4. Extending miscibility (decreasing minimum miscibility pressure)
    - Liquefied petroleum gas, H_2S, or other interfacial tension reduction elements
    - Reduce miscibility requirements by 500 psi (21 reservoirs)

In the report entitled *Storing CO_2 with Next Generation Technology* (NETL, 2008), this definition of "next generation" CO_2-EOR is used to evaluate magnitude of potential to produce incremental oil.

Evaluation of Domestic Technically- and Economically-Recoverable Incremental Oil Resource. Over 6000 oil-bearing reservoirs in the lower 48 states and Alaska were screened to identify those meeting minimum criteria to be further evaluated to determine potential technical and economic incremental oil recovery potential through application of CO_2-EOR. These minimum criteria were minimum field size of 50 million barrels of original oil in place, minimum reservoir depth of 3,000 feet, and minimum crude API gravity of 17.5. Of all reservoirs considered, a subset of 1,600 was identified as meeting these size, depth, and density criteria. These candidate reservoirs were then evaluated using a stream-tube CO_2-EOR model to estimate technical incremental oil under each of the three CO_2-EOR flood operational scenarios. The results from the stream tube model were fed to a cash flow model to estimate the amount of economically recoverable resource at different market prices for crude oil and values for carbon storage. Under the best practices scenario and at a crude oil price of \$70 per barrel and a value for CO_2 storage of \$45 per metric tonne of CO_2, 60 billion barrels of economically recoverable oil was estimated. This amount of CO_2-EOR corresponds to an estimated nine billion metric tonnes of CO_2 sequestration. This volume of CO_2 is roughly equal to captured CO_2 emissions from 50 gigawatts of coal-fired power plants over a 30-year life. Results of this analysis are summarized in Table 3-4 and Table 3-5.

Table 3-3 Definition of CO_2-EOR Technology Scenarios and Data Sources Used in Evaluation of CO_2-EOR Scenarios in Studies Previously Published by NETL

Parameter Description	Historical CO_2-EOR	Best Practices CO_2-EOR	Next-Gen CO_2-EOR				
			Tech 1 Increase CO_2 HCPV	Tech 2 Innovative flood design	Tech 3 Increase Water Viscosity	Tech 4 Miscibility extenders	Tech 1-4 All Next-gen options
Incremental hydrocarbon pore volumes injected	0.4	1	1.5	1[a]	1	1	1.5
Number of injectors	1	1	1	1	1	1	1
Number of producers	1	1	1	2	1	1	2
Viscosity of water (cp)	ARI DB[b]	ARI DB	ARI DB	ARI DB	3 cp	ARI DB	3 cp
Minimum miscibility pressure (psia)	ARI DB	ARI DB	ARI DB	ARI DB	ARI DB	ARI DB - 500	ARI DB – 500
WAG type	Normal	Tapered	Tapered	Tapered	Tapered	Tapered	Tapered
Water chase?	Yes	No	No	No	No	No	No

(Adapted from U.S. DOE, 2006; NETL 2008a; NETL 2008b; NETL 2009).

[a]Grey cells identify next-generation CO_2-EOR technologies that are not considered in this study.
[b] *ARI DB=Advanced Resources International Big Oil Fields Database*

Table 3-4 Summary of CO_2-EOR Injection Scenarios as Defined in Previously Published Reports

	Pore volume injection	CO_2 storage rate ($mtCO_2$/bbl)[a]	Aggregate impacts of CO_2-EOR in the U.S.	
			Crude Oil recovery, (Billion barrels)[b]	CO_2 stored (Bmt CO_2)
Historic CO_2-EOR[c]	0.4	0.11-0.22	10-20	1.0 – 5.0
Best Practices[d]	1.0	0.28	45	12.5[e]
Next Generation[f]	1.5	0.22	64	14.5

[a] *Economically recoverable resource based on a market price for crude oil of $70 per barrel and a CO_2 cost of $45 per metric ton, delivered to the field, and a project IRR of 15% before tax.*
[b] *Conversion factor is 56 MMmt/scf; equivalent values in scf/bbl for historic, best practices, and next generation are 2,000 – 4,000 scf/bbl, 5,000 scf/bbl, and 4,000 scf/bbl respectively.*
[c] *Not modeled as a part of this analysis. Numbers are estimated from industry heuristics*
[d] *"Best Practices" entails 1.0 pore volume CO_2 injection, tapered WAG process, reinjection of CO_2 produced with oil, and a water slug at the end of the flood recovers residual CO_2.*
[e] *ARI estimates that 3.5 billion metric tons of total will be supplied by natural sources and industrial vents. A net of 9 billion mt is the capacity that will motivate advanced coal with CO_2 capture.*
[f] *"Next Generation" entails 1.5 pore volume CO_2 injection, advanced flood design and well placement to improve reservoir contact, increased water viscosity to 3 cps, use of miscibility extenders to reduce the minimum miscibility pressure by 500 psi, and no water slug at the end of the flood to recover CO_2.*

Adapted from U.S. DOE, 2006; NETL 2008a; NETL 2008b; NETL 2009.

Table 3-5: Economically Recoverable Oil and CO_2 Sequestration Capacity in the Conterminous 48 States and Alaska, Estimated Based on Stream-Tube Modeling of Best Practices and "Next Generation" CO_2-EOR Scenarios

Basin/Area	Best Practices[a]			Next Generation[b]	
	Oil produced, Bbbls[c]	CO_2 stored, $MMmtCO_2$		Oil produced, Bbbls	CO_2 stored, $MMmtCO_2$
1. Alaska	9.5	2,094		9.5	2,094
2. California	5.4	1,375		8.1	1,556
3. Gulf Coast (AL, FL, MS, LA)	2.2	652		2.7	691
4. Mid-Continent (OK, AR, KS, NE)	5.6	1,443		8.8	1,845
5. Illinois/Michigan	0.5	127		1.7	329
6. Permian (W TX, NM)	7.1	2,712		15.1	3,598
7. Rockies (CO,UT,WY)	1.9	574		3.8	759
8. Texas, East/Central	8.3	1,940		9.9	2,099
9. Williston (MT, ND, SD)	0.5	130		0.6	122
10. Louisiana Offshore	3.9	1,368		3.9	1,368
11. Appalachia (WV, OH, KY, PA)	0.1	36		0.1	18
Total United States	**45.0**	**12,451**		**64.4**	**14,477**

[a] "Best Practices" entails 1.0 pore volume CO_2 injection, tapered WAG process, reinjection of CO_2 produced with oil, and no water slug at the end of the flood to recover CO_2

[b] "Next Generation" entails 1.5 pore volume CO_2 injection, advanced flood design and well placement to improve reservoir contact, increased water viscosity to 3 cps, use of miscibility extenders to reduce the minimum miscibility pressure by 500 psi, and no water slug at the end of the flood to recover CO_2.

[c] Economically recoverable resource based on a market price for crude oil of $70 per barrel and a CO_2 cost of $45 per metric ton, delivered to the field, and a project IRR of 15% before tax

Source: NETL, 2009

ARI Report on CO_2-EOR Electricity Requirements

A report published by NETL and prepared by Advanced Resources International, Inc. entitled *Electricity Use of Enhanced Oil Recovery with Carbon Dioxide (CO_2-EOR)* provides ranges of unit process electricity demand based largely on input from field operators of existing CO_2-EOR operations (Van Leeuwen and Ferguson, 2009). Table 3-6 summarizes ranges of electricity demands for three major operations: CO_2 re-compression, artificial lifting of produced fluids from CO_2-EOR producing wells, and separation of natural gas liquid (NGL) from CO_2 stream following gas/liquid separation. A fourth range is provided as an estimate of the sum of electricity demands from all other processing activities taking place during CO_2-EOR facility operation.

Table 3-6 Range of Electricity Use at CO_2-EOR Fields by Source

Project Component	Low Bound Electricity Consumption[a]	Mid Range Electricity Consumption[b]	High Bound Electricity Consumption[c]
Compression	26 kWh/Bbl	40 kWh/Bbl	70 kWh/Bbl
Artificial Lifting	0 kWh/Bbl	5 kWh/Bbl	10 kWh/Bbl
NGL Separation	0 kWh/Bbl	0 kWh/Bbl	10 kWh/Bbl
Other	1 kWh/Bbl	5 kWh/Bbl	8 kWh/Bbl
Total	**35 kWh/Bbl**	**60 kWh/Bbl**	**98 kWh/Bbl**
[a] This estimate represents a field with a permeable reservoir, optimized compression equipment, free flowing wells, no additional hydrocarbon separation equipment and that injects straight CO_2.			
[b] A mid-range field injects greater volumes of CO_2 into the reservoir, or has somewhat inefficient compression equipment. It requires artificial lift equipment to produce its oil and injects some of its produced water in a WAG flood.			
[c] A high-electricity use field injects large amounts of CO_2 into its reservoir. This flood is likely producing large amounts of oil from a deep reservoir, which requires powerful, somewhat inefficient artificial lifting equipment. This field also employs a hydrocarbon separation facility that requires additional energy to compress the refrigerant used in the Ryan Holmes process. Finally, it injects its produced water in a WAG process.			

Source: Van Leeuwen and Ferguson (2009)

These data provide a useful example of the variability in the type of operation and efficiency of performance that may be expected from CO_2-EOR operations. The report also highlights the scarcity of this type of performance data. The way in which these data are reported is not conducive to development of more than a screening-level life cycle inventory for enhanced oil recovery. All data are reported in terms of barrels of crude oil produced, while the scale of operations cannot be directly correlated to oil flow (CO_2 compression electricity requirements, for example, are reported in terms of kWh/barrel of oil produced even though the compression requirements are more a function of volume or mass of gas compressed than oil produced).

3.3.2 Literature Review of CO_2-EOR Environmental Performance

Several assessments of CO_2-EOR have been reported at technical conferences or in peer-reviewed literature. Table 3-7 provides a summary of characterizations that endeavor to describe CO_2-EOR operations in basins or a specific field the Permian Basin, West Texas. The broad range of estimated CO_2 storage potential per barrel of oil produced and EOR facility operational emissions reflects the high degree of variability in flood performance resulting in variability in reservoir continuity from well to well, and differences in CO_2-EOR practice. CO_2-EOR field operation and performance vary significantly from basin to basin, field to field, operator to operator, and even well pattern to well pattern. This variability also reflects differences in how the LCA practitioner models activities and related resource demands and environmental emissions; such differences could result from differing study scopes or differences in complexity of model structure.

The most reliable estimates of emissions associated with CO_2-EOR operations are those that are based on real inventory of site-specific material flows, energy flows, and unit process performance. For example, values reported for the Scurry Area Canyon Reef Operators (SACROC) facility near Snyder, Texas (unpublished presentation Kinder-Morgan CO_2 Company, 2009) are based on a detailed inventory of 2007 operations at that facility. This type of analysis can be reasonably assumed to provide a robust characterization of performance at the SACROC facility, but these results cannot be used to characterize performance for individual well patterns within the SACROC field, nor all fields in the Permian Basin, let alone in all basins in the United States.

One key factor that will impact operational emissions for CO_2-EOR scenarios with gas processing and recycle is the cumulative injection volume of CO_2—commonly reported as HCPVs of CO_2 injected. In current best practice, cumulative CO_2 injection in WAG operations is typically in the range of 0.8 to 1.0 HCPV, but real cumulative injection volumes vary as a function of field properties, economic conditions, and operator judgment (Melzer, 2010). Cumulative CO_2 injection often varies on a pattern-by-pattern basis and, as such, field-level CO_2 cumulative injection volumes are not typically reported.

Choice of study boundary can also significantly impact results of an LCA. Assessments summarized in Table 3-7 consider only activity during the operational phase, and do not consider site evaluation, construction and workover requirements, well plugging and abandonment, or post-closure monitoring. While most environmental emissions associated with CO_2-EOR occur during EOR operations, a more complete characterization should also consider phases of operation. The present study attempts to estimate emissions associated with all phases of operation.

Table 3-7 Summary of Characterizations of CO_2-EOR GHG Performance Reported from Other Studies

Source	Scope	Location	Gross Storage Capacity (kg CO_2/bbl)	GHG Emissions (kg CO_2E/bbl)	Net GHG Storage (kg CO_2E/bbl)
(Jaramillo et al., 2009)	Operation	Northeast Purdy Unit, Mid Continent, OK, USA	172	57	115
	Operation	Kelly Snyder Field, Permian Basin, W. TX	218	57	161
	Operation	Ford Geraldine Unit, Permian Basin, W. TX	182	57	125
	Operation	Joffe Viking Unit, Alberta,CAN	157	57	100
	Operation	Weyburn Unit, Williston Basin, SK, CAN	154	57	97
(Fox, 2009)[a]	Operation	Kelly Snyder Field, Permian Basin, W. TX	404	100	304
Estimated from Aycaguer & Lev-On (2000)	Operation	Permian Basin-type reservoir	409	56	353
Kovscek (2002)	Operation	Non-specific	360	n/r[b]	n/r

[a]Kinder-Morgan inventory of SACROC facility operations was presented but not published or approved for distribution. As such, it should be noted that values reported herein are not sanctioned by the authors of that study.
[b]n/r - not reported

3.4 CO_2 Prophet CO_2-EOR Screening Model

In 1986, a Fortran-based model was developed by researchers at the Texaco Exploration and Production Technology Department, as part of the U.S. DOE Class I cost-shared project *Post Waterflood, CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir*, under U.S. DOE ContractDE-FC22-93BC14960. The CO_2 Prophet model was recompiled by Dr. S. M. Avasthi (Avasthi & Associates) to run on 32-bit PCs operating Microsoft Windows XP, and has been reviewed and validated by NETL staff (Remson, 2006). The CO_2 Prophet model has also been used in a series of basin-specific evaluations of CO_2-EOR potential, and for evaluation of “best practices” and “next-generation” practices technology scenario evaluation studies published by NETL and summarized in the body of this report. Finally, the electricity demand for three general geographic CO_2-EOR scenarios (W. Texas, Gulf Coast/Mississippi, and California) were estimated based on production estimates developed using CO_2 Prophet and partially described in a fourth report published by NETL and summarized in the body of this text.

3.4.1 Summary of CO_2 Prophet Screening Model

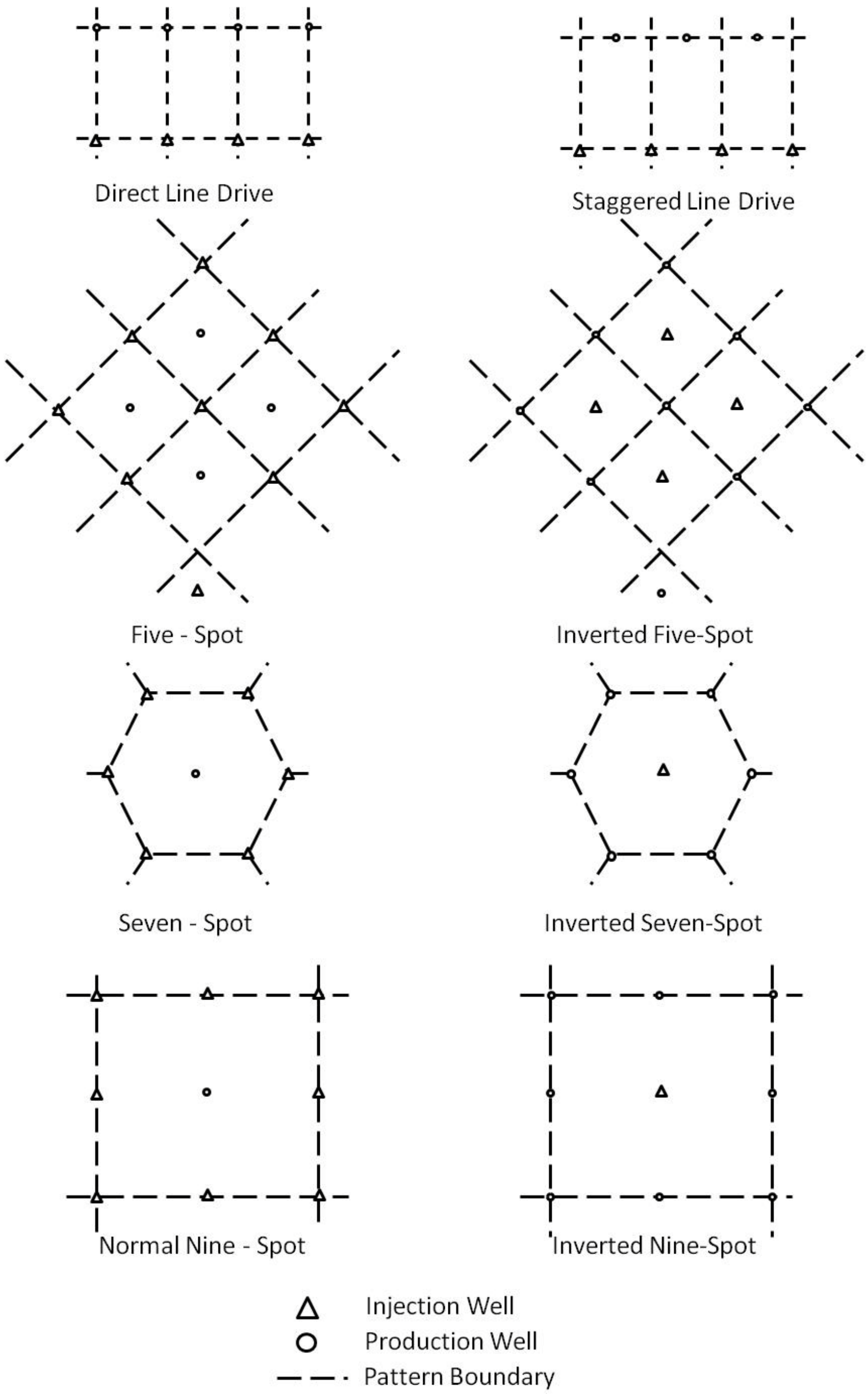
The CO_2 Prophet model performs two main operations. The model generates streamlines to describe fluid flow between injection and production wells, and then performs oil displacement and recovery calculations along the streamlines using a finite difference routine to calculate oil displacement. CO_2 Prophet handles areal sweep efficiency by incorporating streamlines that are a function of well spacing, mobility ratio, and reservoir heterogeneity.

Required input parameters for the CO_2 Prophet model fall into the following broad categories:

- Fluid property parameters
- Reservoir property parameters
- Relative permeability parameters
- Flood pattern configuration specifications
- Injection scenario parameters

Fluid properties that need to be defined before running the model include viscosity of oil, viscosity of water, solution gas-oil ratio, API gravity of oil, water salinity, and gas-specific gravity. Key reservoir properties that directly influence oil recovery are initial residual oil saturation, Dykstra-Parsons coefficient, oil and water viscosity, reservoir pressure and temperature, and minimum miscibility pressure (assuming flooding operations are to be carried out about the MMP). Mixing parameters, as defined by Todd and Longstaff (1972) and detailed in Appendix A, are used in CO_2 Prophet for simulation of the miscible CO_2 process, particularly CO_2/oil mixing and the viscous fingering of CO_2.

The CO_2 Prophet model contains a set of standard reservoir patterns, including 5-spot, line-drive, and inverted 9-spot (commonly used injection patterns are summarized in Figure 3-4 and Table 3-8); custom well patterns can also be defined by the user in the Prophet model. CO_2 Prophet injection parameters can be modified to simulate a variety of recovery processes, including continuous miscible CO_2, WAG miscible CO_2 and immiscible CO_2, as well as waterflooding. Performance of the CO_2 Prophet model in prediction of miscible flooding (1 HCPV, California San Joaquin Basin, Elk Hills reservoir) was previously reported to compare favorably with modeling results derived from an industry standard reservoir simulator, GEM. Despite the absence of a gravity override parameter in the Prophet model, it was demonstrated to provide an oil recovery prediction that is neither overly pessimistic nor overly optimistic, and was therefore determined to be an acceptable tool for scoping of reservoir performance (NETL, 2008).



Adapted from Manning and Thompson (1995)

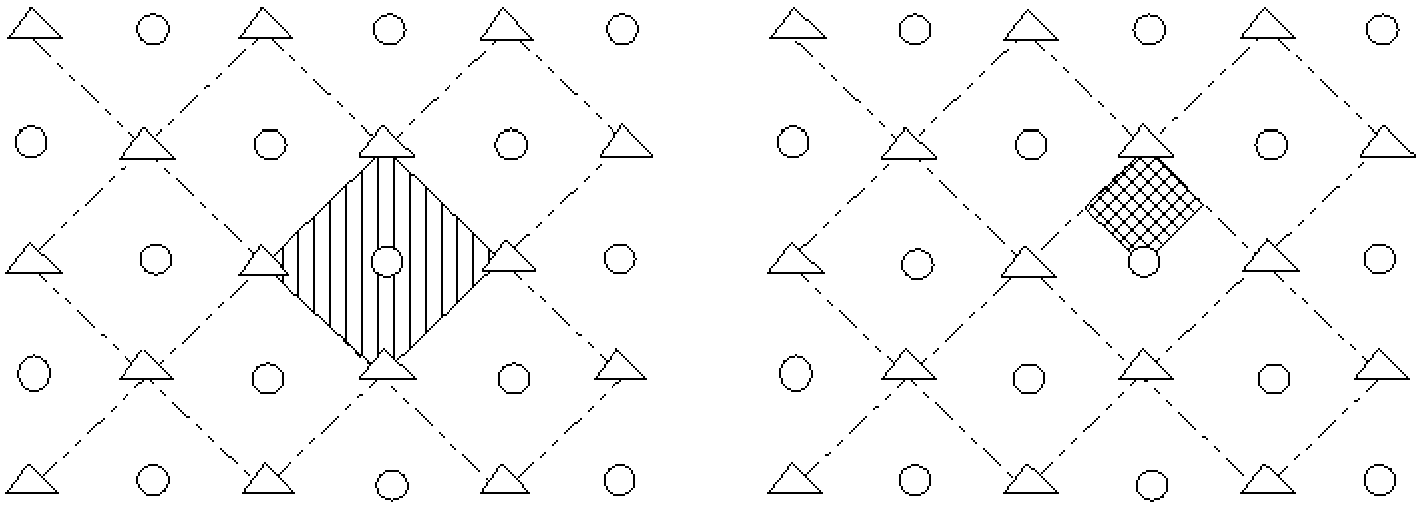
Figure 3-4 Illustration of Several Well Geometries Commonly Used for Enhanced OilRecovery

Table 3-8 Production Well to Injection Well Ratio for a Series of Common EOR Well Patterns

Pattern type	Drilling Pattern	Well Ratio Producers : injectors
Direct Line Drive	Rectangle	1
Staggered Line Drive	Offset	1
Five-Spot	Square	1
Inverted Five-Spot	Square	1
Seven-Spot	Equilateral Triangle	0.5
Inverted Seven-Spot	Equilateral Triangle	2
Normal Nine-Spot	Square	0.33
Inverted Nine-Spot	Square	3

Referenced from Manning and Thompson (1995)

Finally, injection schedule is a function of operator preference and reservoir injectivity limitations. As detailed above, the rate and order in which CO_2 and brine are injected in a WAG injection scenario will affect the rate of oil and gas production, time to CO_2 breakthrough, and ultimate resource recovery efficiency of the flood.



(a) area of 5-spot well pattern **(b) portion of 5-spot pattern simulated in CO_2 Prophet model**

Figure 3-5: Surface Area of a 5-Spot Well Pattern and Portion Simulated in Prophet Model

Source: CO_2 Prophet Model Documentation (1986)

3.4.1.1 Estimation of CO_2-Flood Performance Using CO_2 Prophet Screening Model

Reservoir parameter values used to define the CO_2-EOR base case considered in this study were taken from the average values reported in the proprietary database developed by ARI, Inc., and provided to NETL under a license agreement (ARI, Inc., 2009). This database reports reservoir characteristics, reservoir fluid property, well count, cumulative historical production data for 228 reservoir cases within the Permian Basin, as well as data for Mid Continent (OK, AR, KS, NE), Rockies (WY, UT, CO), California, Gulf Coast, Williston Basin, East and Central Texas, Illinois, and Appalachian basins. Permian Basin-type parameter values were selected because the Permian Basin is both the location of the majority of current CO_2-EOR activity, and because it holds significant potential for future domestic tertiary incremental oil production.

Identifying Representative Reservoir and Fluid Properties for Use in Analysis Scenarios. Data reported in the ARI "Big Oil Fields Database" were not used directly to define the reservoir scenario used in base case and subsequent scenario analyses of CO_2-EOR Operations. Because this database is a proprietary resource, direct reporting of these data was not permitted. In addition, evaluation of a particular reservoir was not necessary, given that the goal of this effort was to more generally evaluate CO_2-EOR relative performance under different operational scenarios. The database was, however, used to identify acceptable ranges of parameter values for a single basin. Distribution metrics (mean, standard deviation, median, minimum value, maximum value) for a number of reservoir and reservoir-associated fluid parameter values were considered and basin-representative values within the range of observed values were selected. Selected parameter values for reservoir and fluid properties are listed in Table 3-9 and Table 3-10, along with mean, standard deviation, and median values for the Permian basin from the ARI "Big Oil Fields" database (based on a nominal sample size of 228 reservoirs).

Table 3-9 Fluid Parameter Values Used in Modeling of CO_2-EOR Scenarios and Mean and Standard Deviation Values from ARI Database Permian Basin Reservoirs (n=228)

Parameter Description	Parameter Value Used in This Study	ARI Database Mean	Standard Deviation	Median	Units
Viscosity of oil	1.76	4.67	24.78	1.76	cp
Viscosity of water	0.72	0.721	0.228	0.72	cp
Oil formation volume factor	1.2	1.199	0.156	1.16	(RB/STB)
Solution gas-oil ratio	805	804.5	1138.9	500	scf/STB
API Gravity of Oil	36	36.29	5.55	36	ºAPI
WATER SALINITY	96,000	95,934	62,480	90,000	parts per million
Gas specific gravity	0.65	0.650	0.003	0.65	(Air = 1.0)
C5+	183	*	*	*	g/mole

* Calculated from ° API

Table 3-10 Reservoir Parameter Values Used in Modeling of CO_2-EOR Scenarios and Mean and Standard Deviation Values from ARI Database for Permian Basin Reservoirs

Parameter Description	Parameter Value Used in This Study	ARI Database				Units
		No. of samples	Mean	Std. Dev.	Median	
Reservoir temperature	123	228	123.5	35.6	112	ºF
Reservoir pressure	2,368	205	2,368.5	1,124.7	2,100	psia
Minimum miscibility pressure	1523	-	[b]	[b]	[b]	psia
Dykstra-Parson Coefficient in the production zone	0.73	224	0.73	0.151	0.75	dimension -less
Average permeability of the reservoir production zone	29	228	28.97	135.5	8	md
Total vertical depth	5,826	224	5,826.4	2,665.7	4,700	Feet to top of reservoir
Net pay (thickness) of reservoir	76	228	76.1	72.5	55	Feet
Actual porosity of field	0.11	228	0.11	0.0428	0.105	fraction (0-1)
Swept oil saturation value in all segments	0.32	228	0.306	0.054	0.30	fraction (0-1)
Initial gas saturation value in all segments	0	-	[a]	[a]	[a]	fraction (0-1)

[a] Not reported in ARI database, default value from CO_2 Prophet used
[b] Calculated from C5+ (calculated value) and mean reservoir temperature

Fluid relative permeability parameter values are not provided in the database and default values from the CO_2 Prophet model are used except where noted. A complete list of relative permeability parameter assumptions are listed in Appendix A.

Defining Flood Schedule in "Historical," "State-of-Art," and High CO_2 WAG CO_2-EOR Scenarios. In addition to fluid, reservoir, and relative permeability parameters, it was also necessary to specify the volumes and timing of injection of water and CO_2 for each CO_2-EOR operational scenario. The specific injection schedules used in previous studies to evaluate each CO_2-EOR operational scenario were not explicitly defined. Injection schedule parameters were selected based on the author's best understanding of descriptions given in previously published reports.

"Historical" CO_2-EOR, as defined in DOE Basin-Specific CO_2-EOR studies and subsequent NETL studies, assumes a WAG injection of 0.4 HCPVs. Table 3-11 summarizes model parameters that have been used to define a "historical" CO_2- EOR flood. This scenario calls for injection of a water slug following completion of CO_2 WAG injection in order to recover remaining mobile oil and a small amount of CO_2 that will be used in less mature and nearby patterns.

Table 3-11: Injection Schedule Parameters Used in Defining "Historical" Miscible CO_2-flood EOR in the CO_2 Prophet Screening Model

Parameter Description	Cycle[a]				Units
	1	2	3	4	
Water/CO_2 Injection Ratio	-	1.0	2.0	inf.	HCPV:HCPV
Incremental hydrocarbon pore volumes CO_2 injected.	0.2	0.1	0.1	0	HCPVs of CO_2
Injection rate of water, in surface units (SURF BBL/D)	-	562	562	562	surface bbl/day
Injection rate of CO_2, in surface units (MMscf/D)	1.24	1.24	1.24	-	MMscf CO_2/day

[a] All injection cycles reported in terms of volume, as opposed to time.

As defined in previous studies (NETL, 2008) and summarized earlier, "best practices" CO_2-EOR operational scenario involves injection of significantly higher volumes of CO_2 to increase sweep efficiency and improve incremental oil recovery over that which could be accomplished using "historical" injection design. To model this scenario, a total CO_2 injection of 1.0 HCPV was specified, with injection performed using WAG process. In contrast to the historical CO_2-EOR scenario, no water slug is applied at the end of WAG injection. Model parameters selected to describe "best practices" WAG injection scenario are summarized in Table 3-12.

Table 3-12: Injection schedule parameters used in defining "best practices" miscible CO_2-flood EOR in the CO_2 Prophet screening model

Parameter Description	Cycle[a]				Units
	1	2	3	4	
Water/CO_2 injection ratio	-	1.0	2.0	3.0	HCPV:HCPV
Incremental hydrocarbon pore volumes CO_2 injected	0.25	0.25	0.25	0.25	HCPVs of CO_2
Injection rate of water, in surface units (SURF BBL/D)	-	562	500	562	surface bbl/day
Injection rate of CO_2, in surface units (MMscf/D)	1.24	1.24	1.24	1.24	MMscf CO_2/day

[a] All injection cycles reported in terms of volume, as opposed to time.

Modeling High-CO_2 Injection Scenario

As described above and detailed in a previously published NETL report entitled *Storing CO_2 with Next Generation Technology*, the "next generation" CO_2-EOR technology scenario calls for increased injection above the "best practices" scenario of 1.0 HCPV, to 1.5 HCPV. As with the "best practices" scenario, a tapered WAG is also employed, with CO_2 recycling. "Next generation" CO_2-EOR scenarios requiring infill well placement, or polymer addition to increase water viscosity to 3 centipoise, or miscibility extenders are not considered in this study. As with "best practices" CO_2-EOR (and in contrast to "historic" CO_2-EOR), the "next generation" scenario does not call for a water slug to be injected following completion of the CO_2 slug, allowing more CO_2 retention in the formation than would be observed with "chase" water sweep. Injection schedule defining the high CO_2 injection scenario considered in this study is detailed in Table 3-13.

Table 3-13 Injection Schedule Parameters Used in Defining 1.5 HCPV CO_2 Miscible WAG EOR in the CO_2 Prophet Screening Model

Parameter Description	Cycle[a]				Units
	1	2	3	4	
Water/CO_2 injection ratio	-	1.0	2.0	3.0	HCPV:HCPV
Incremental hydrocarbon pore volumes CO_2 injected. [1]	0.4	0.4	0.4	0.3	HCPVs of CO_2
Injection rate of water, in surface units (SURF BBL/D)[1]	-	562	562	562	surface bbl/day
Injection rate of CO_2, in surface units (MMscf/D)[1]	1.24	1.24	1.24	1.24	MMscf CO_2/day

[a] All injection cycles reported in terms of volume, as opposed to time.

Definition of Well Pattern and Injection Characteristics

For this study, a forty-acre, five-spot pattern has been for all CO_2-EOR scenarios. The assumption of a 40-acre, five-spot well pattern is in line with that which was made for historic and best practices scenarios in previous NETL CO_2-EOR studies (U.S. DOE NETL, 2008). This well configuration has a corresponding injection/production well ratio of 1:1.

3.4.2 Results of CO_2 Prophet Runs for Individual Flood Pattern

The following series of figures provide illustration of single-well pattern fluid injection and production profiles for the three previously described injection scenarios: historical, best practices, and 1.5 HCOV CO_2 WAG injection. Plots of incremental and cumulative injection of water (thousands of standard barrels [MSTB] per year) and CO_2 (millions of standard cubic feet [MMscf] per year) define the injection schedule appropriate for each scenario. Incremental production estimates for all fluids (oil, brine, CO_2, and hydrocarbon gas) are also plotted. These model inputs and outputs serve as the basis on which estimates of incremental oil and gas production, CO_2 storage potential, fluid processing infrastructure requirements, processing resource demands, and environmental emissions have been developed.

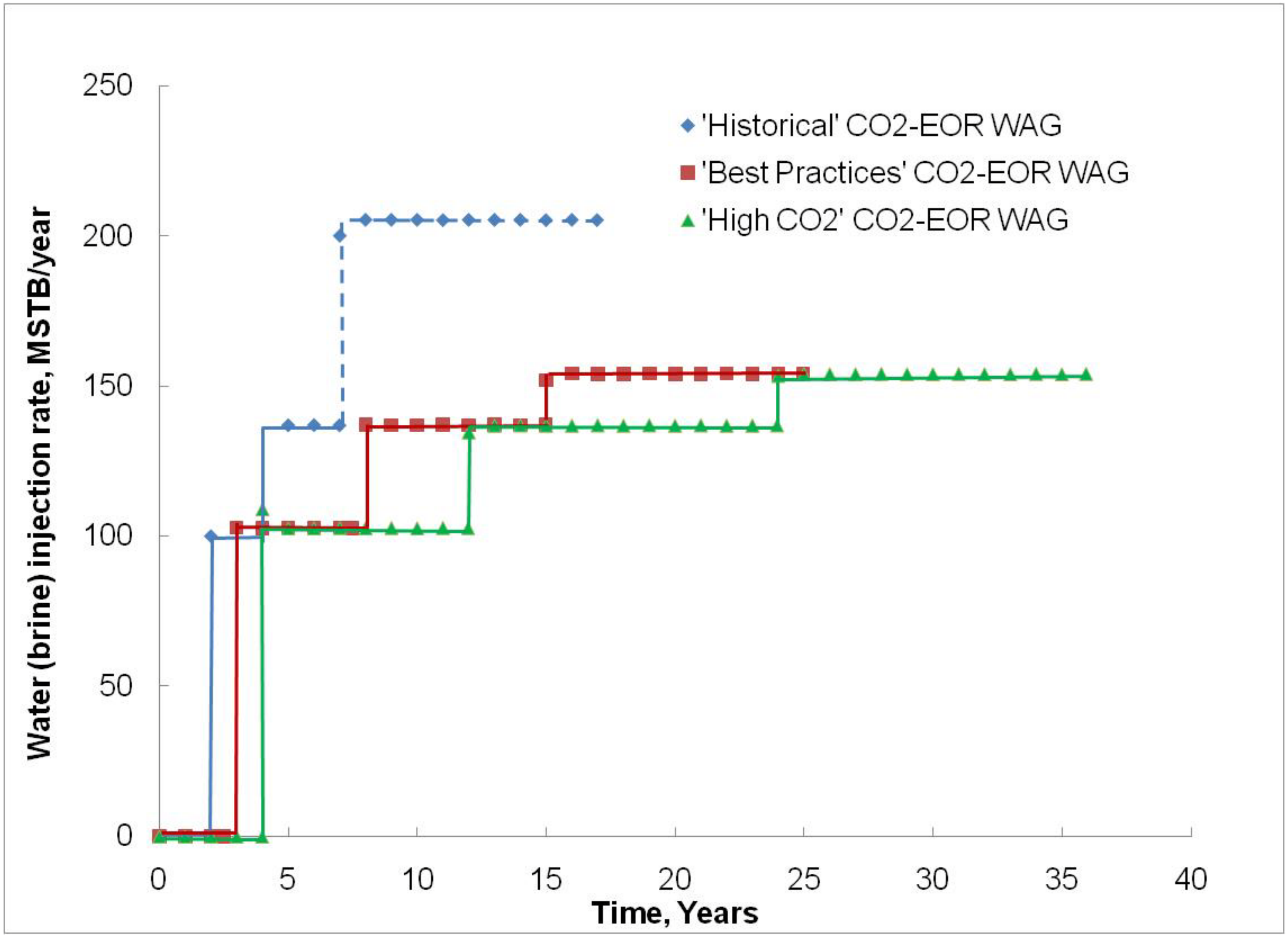


Figure 3-6 Incremental Water Injection Schedule for WAG Injection Scenarios (MSTB water/year)

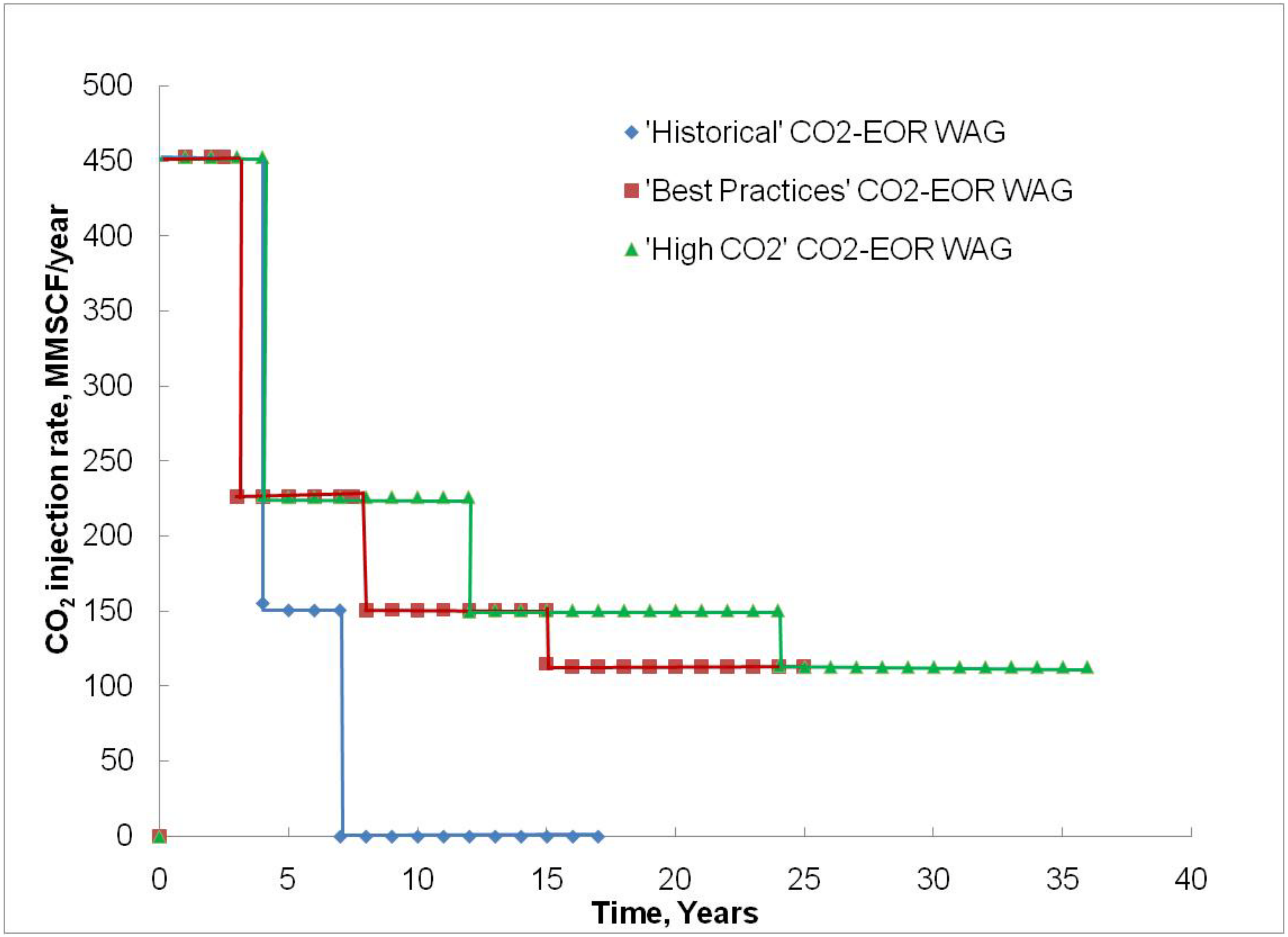


Figure 3-7: Incremental CO_2 Injection Schedule for WAG Injection Scenarios (MMscf CO_2/year)

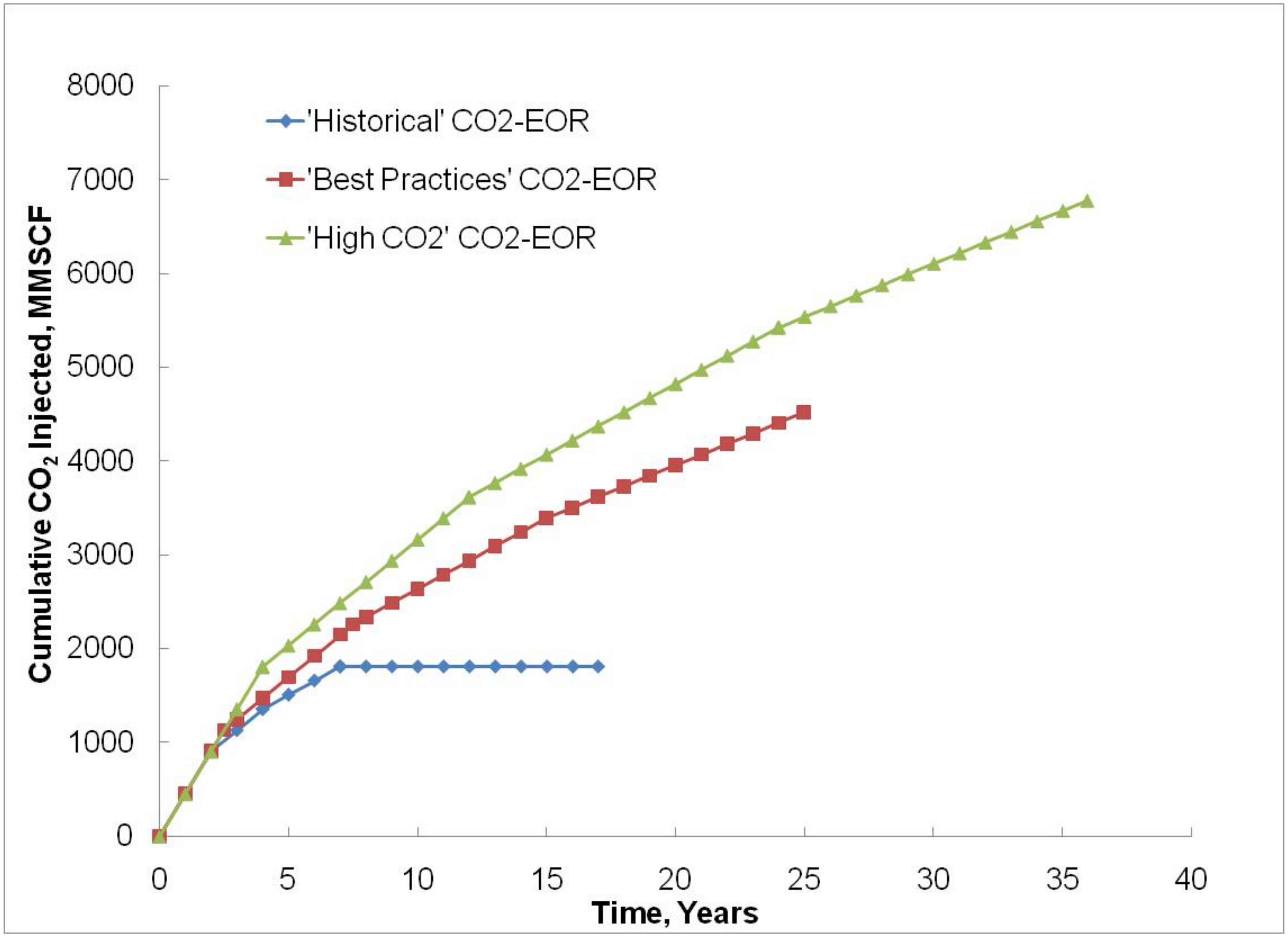


Figure 3-8 Cumulative CO_2 Injection Profile for WAG Injection Scenarios (MMscf)

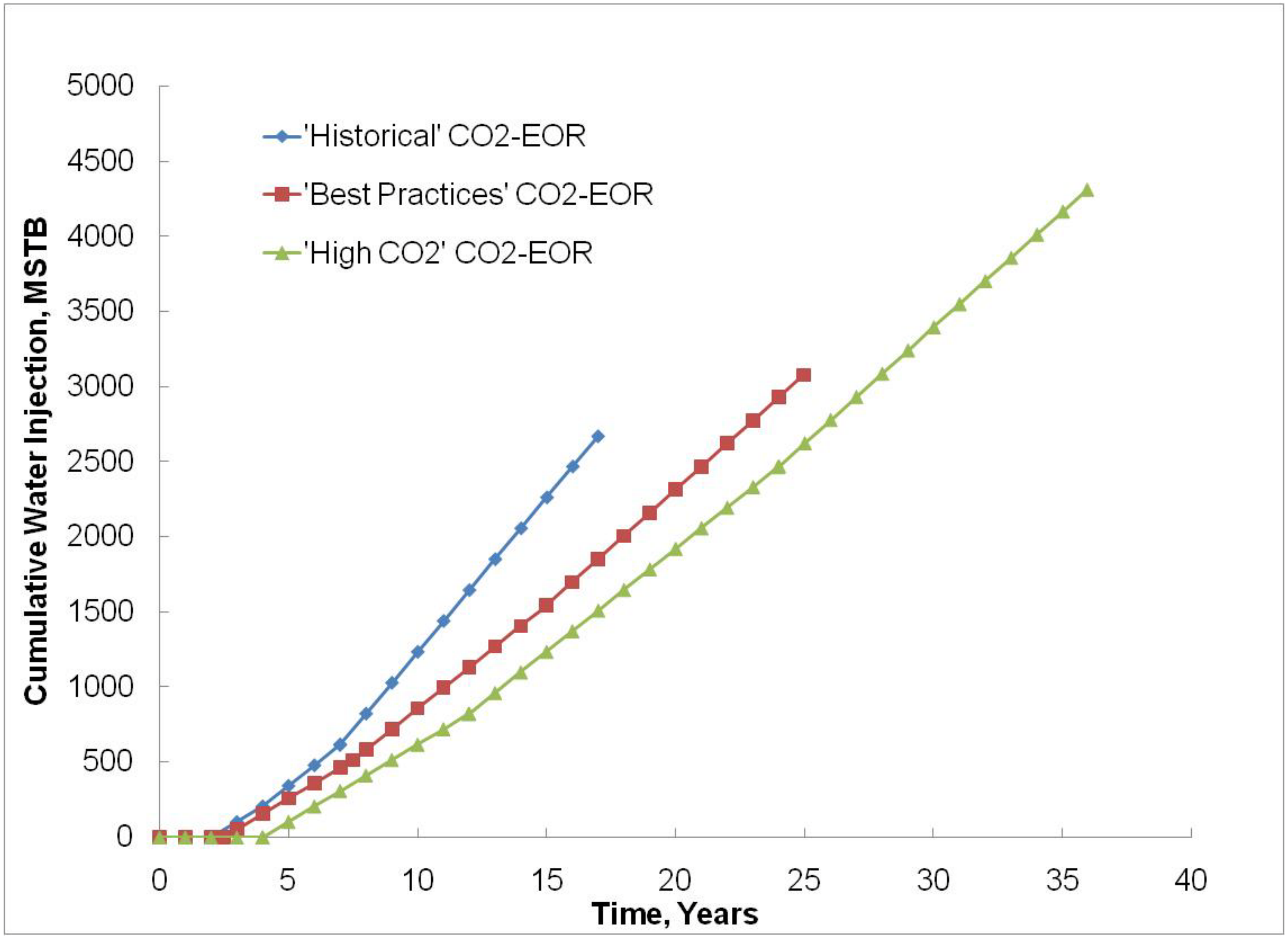


Figure 3-9 Cumulative Water Injection Profile for WAG Injection Scenarios (MSTB)

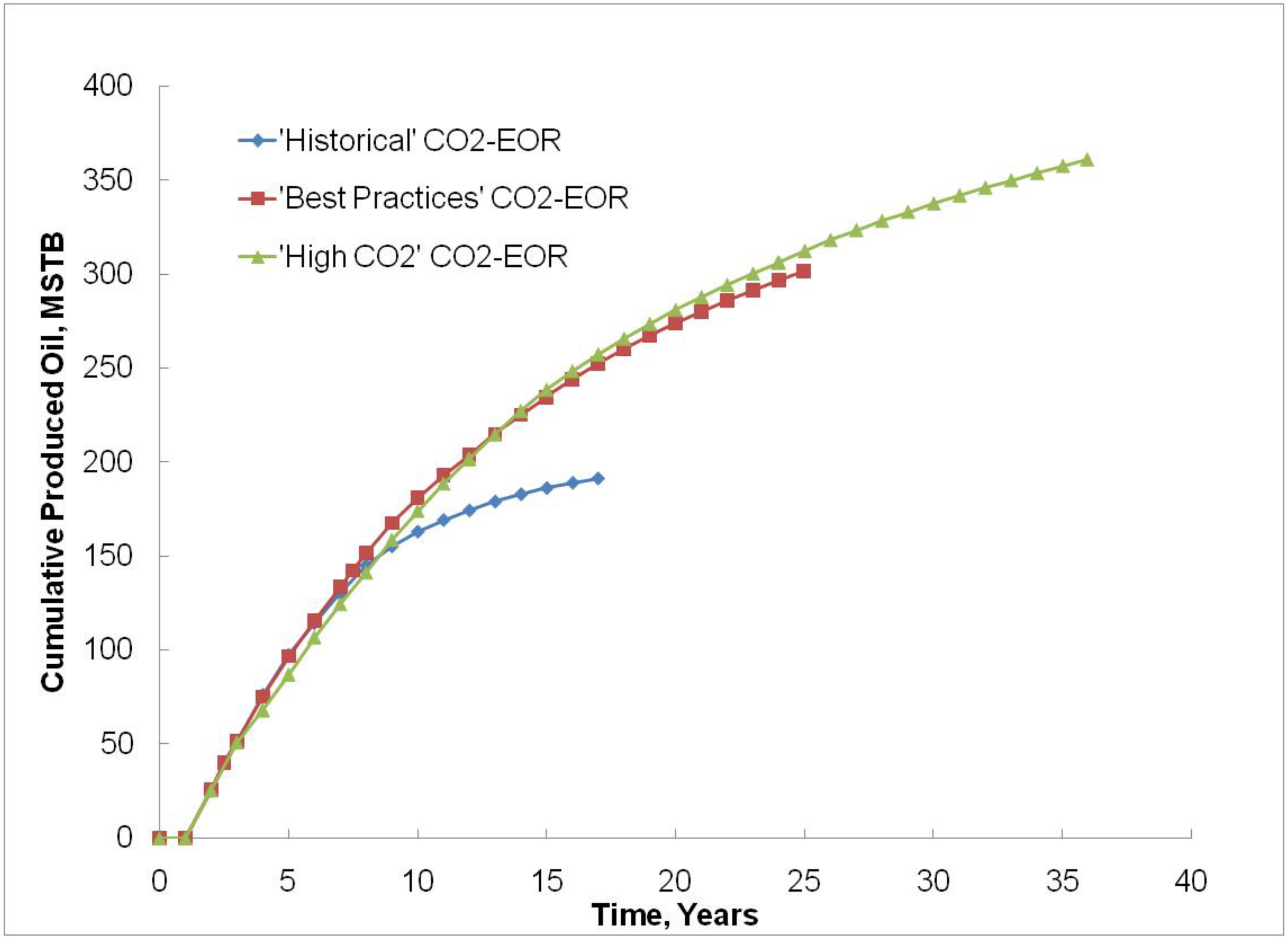


Figure 3-10 Cumulative Oil Production Profile for WAG Injection Scenarios (MSTB)

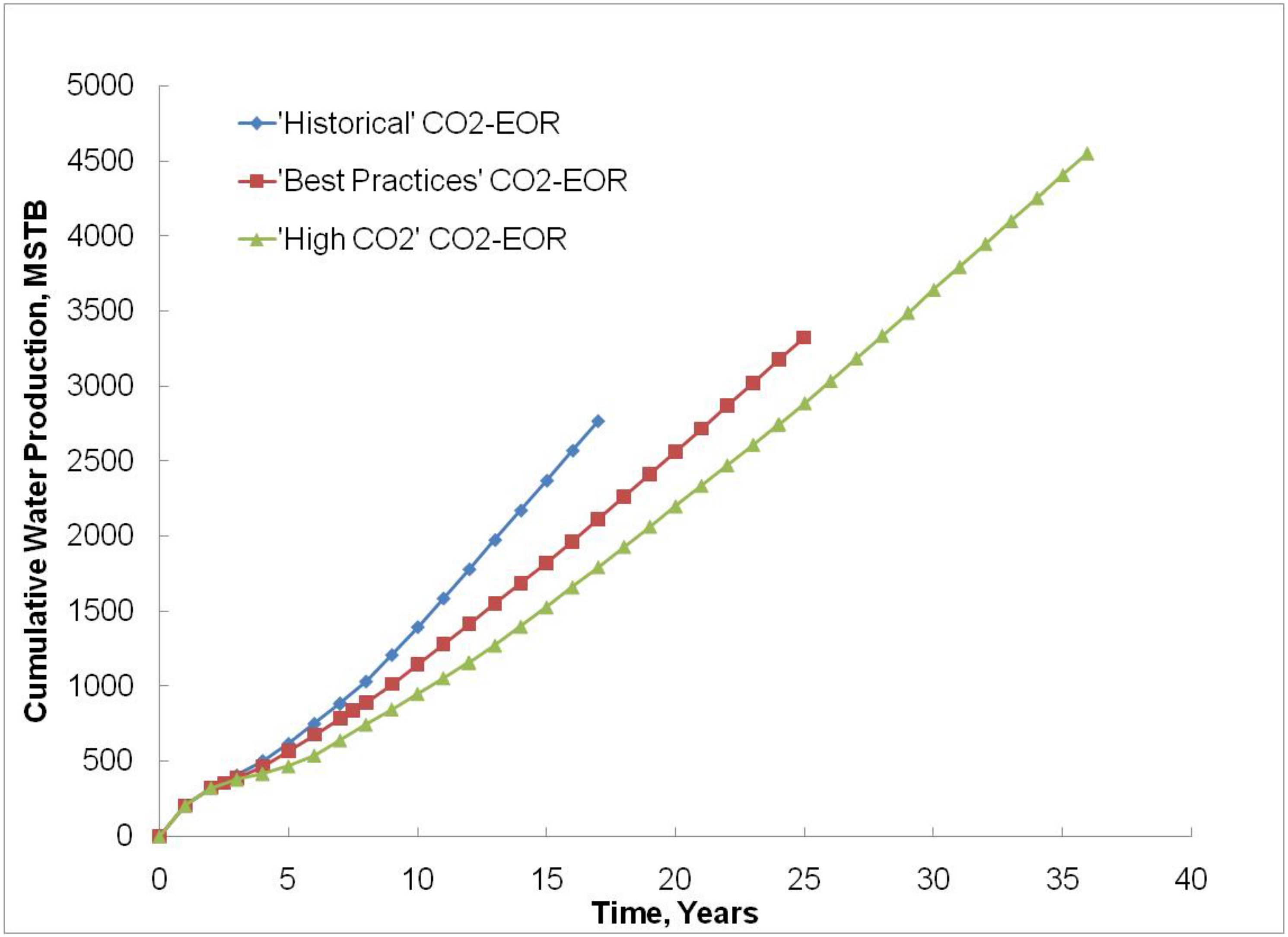


Figure 3-11 Cumulative Water Production Profile for WAG Injection Scenarios (MSTB)

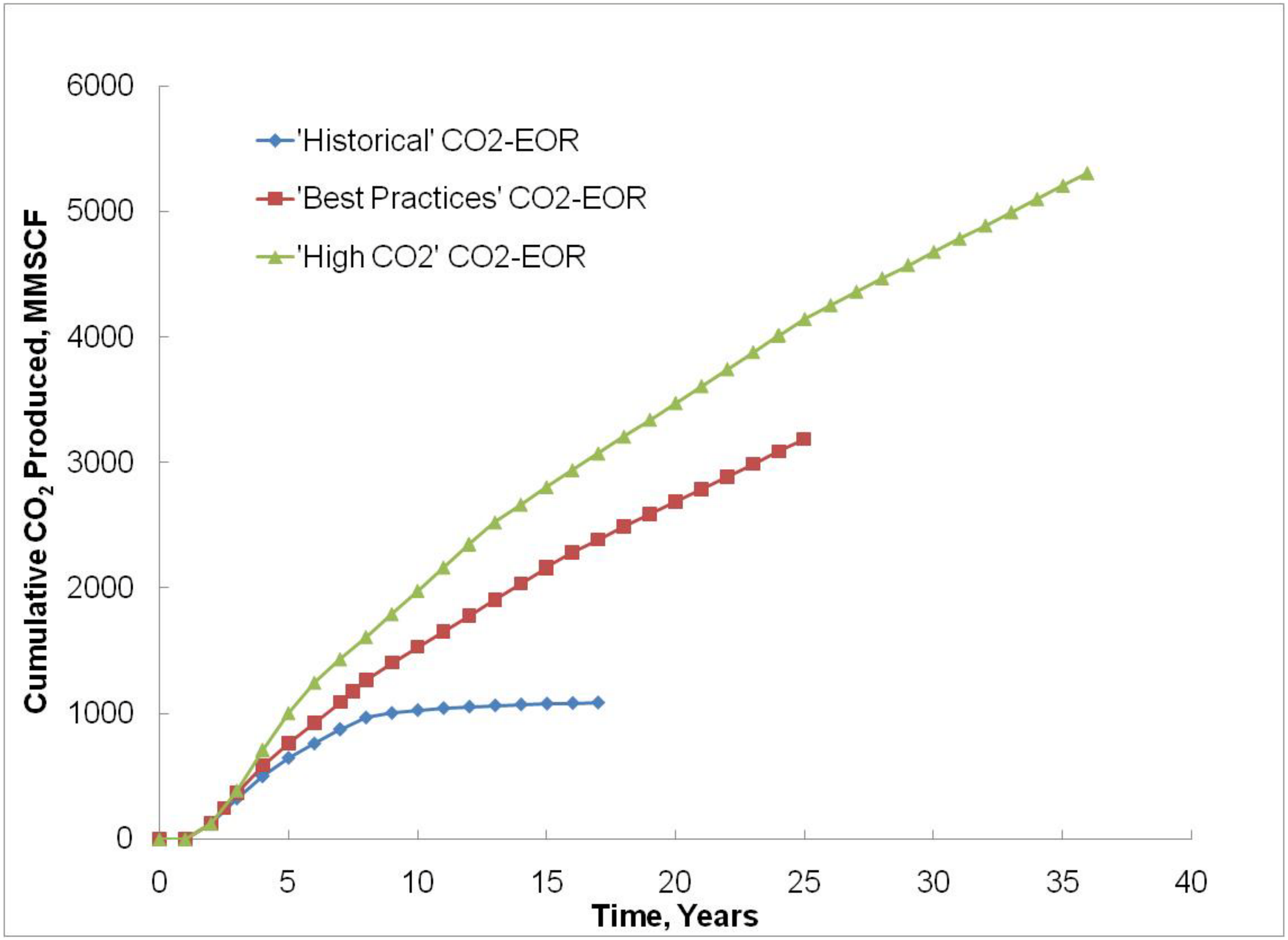


Figure 3-12 Cumulative CO_2 Production Profile for WAG Injection Scenarios (MMscf)

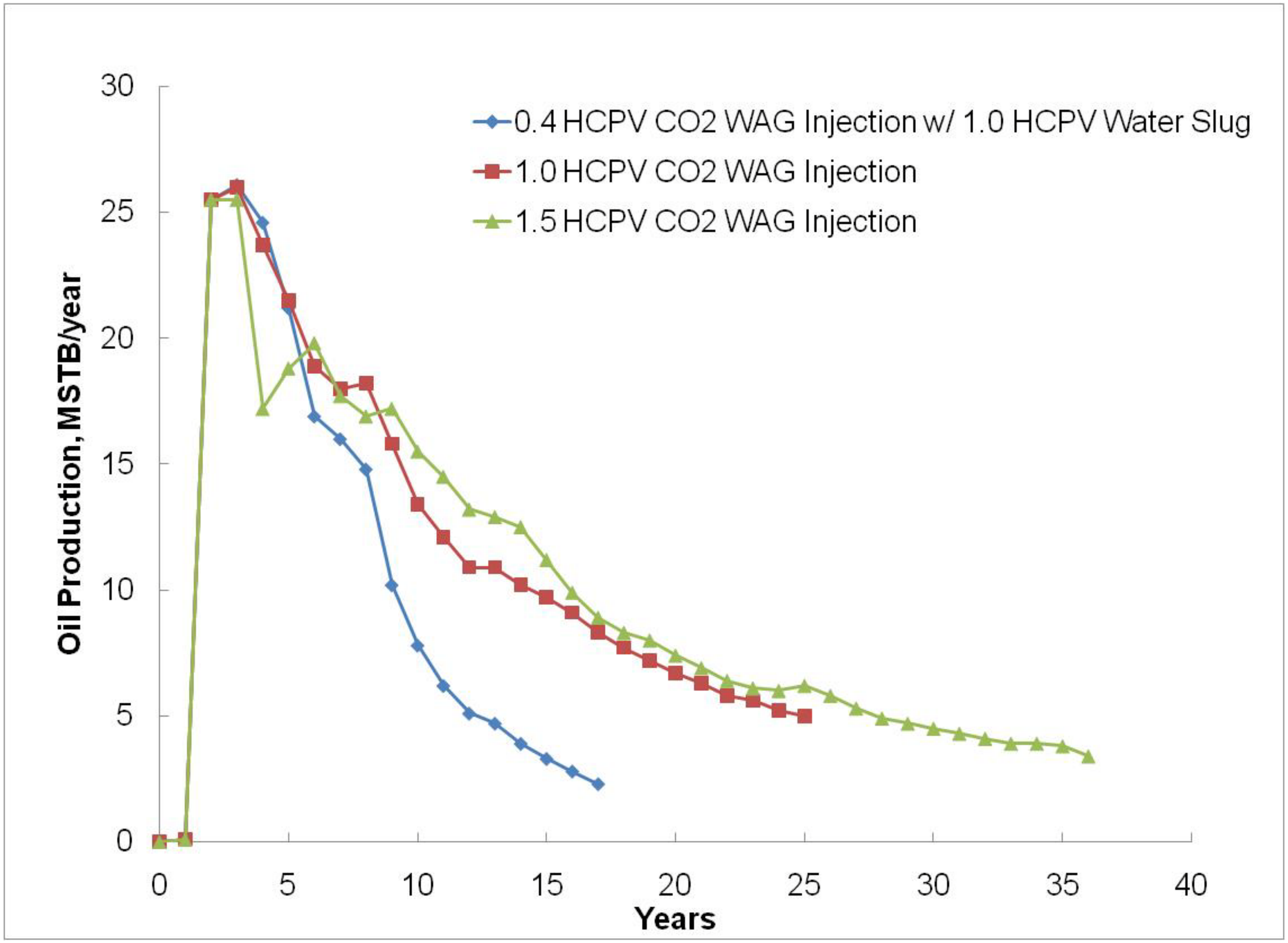


Figure 3-13 Incremental Oil Production for WAG Injection Scenarios (MSTB/yr)

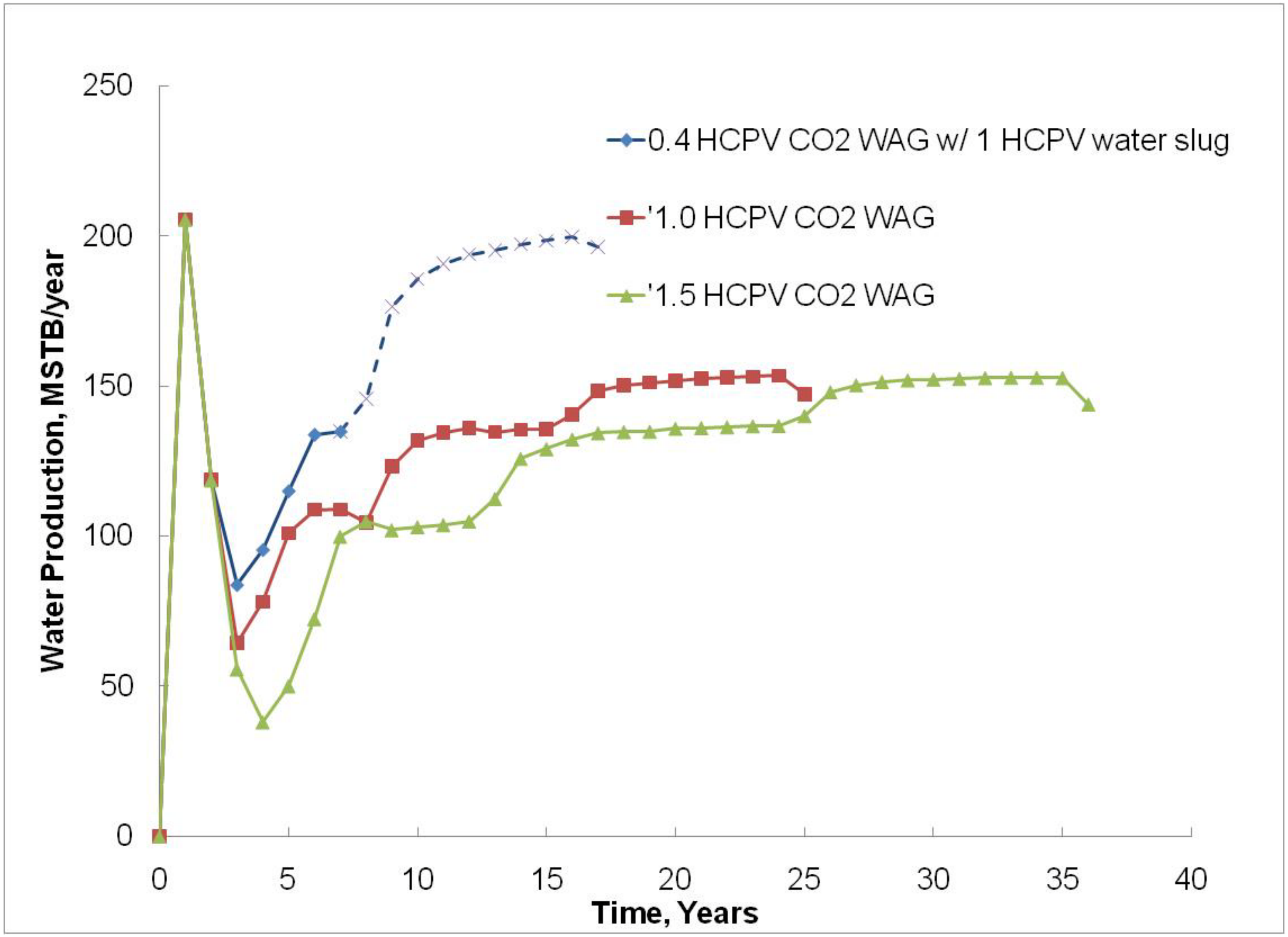


Figure 3-14 Incremental Water Production for WAG Injection Scenarios (MSTB/year). Dotted line in historical CO_2-EOR scenario represents brine production response after initiation of water slug.

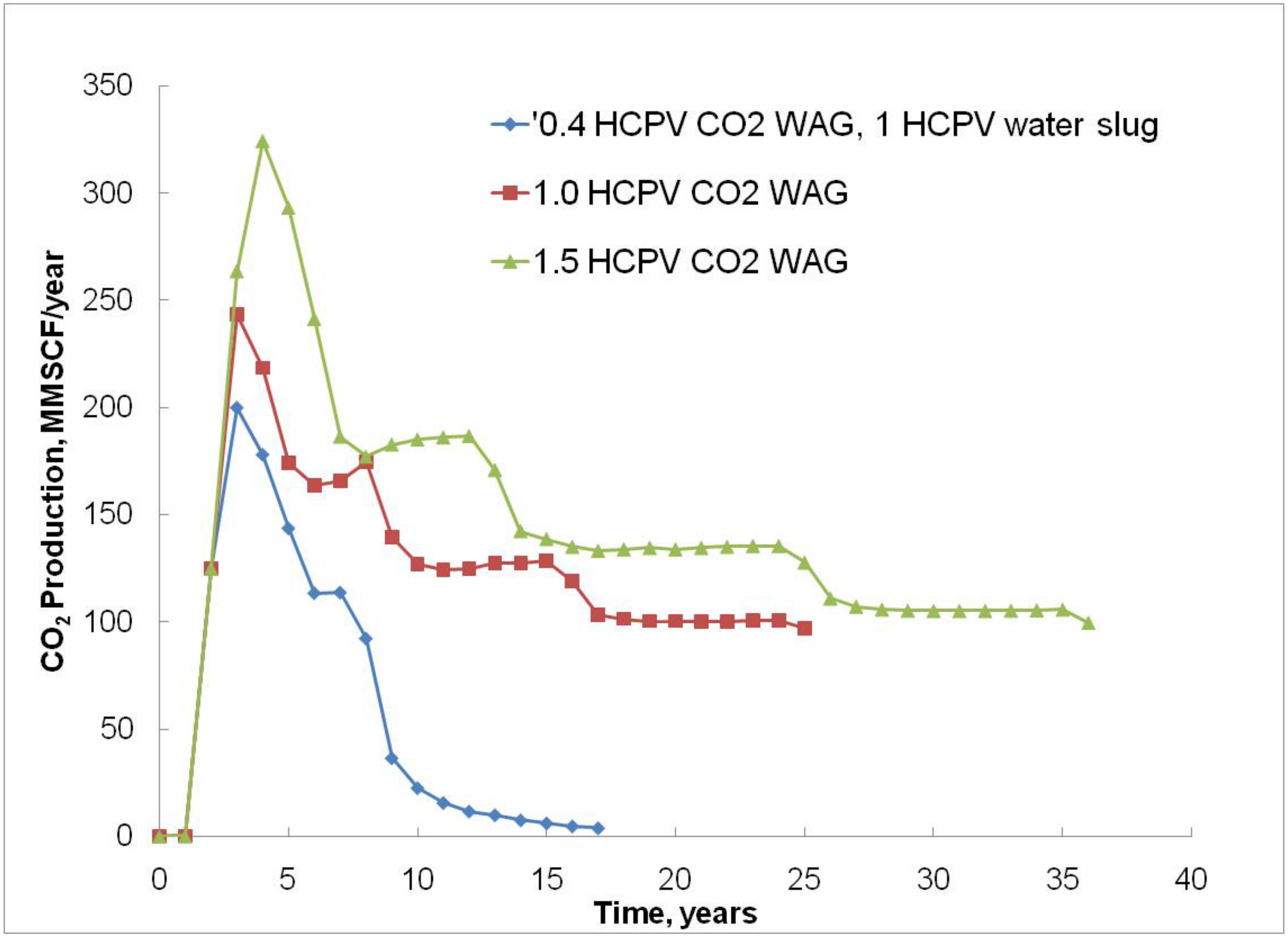


Figure 3-15 Incremental CO_2 Production for WAG Injection Scenarios (MMscf/year)

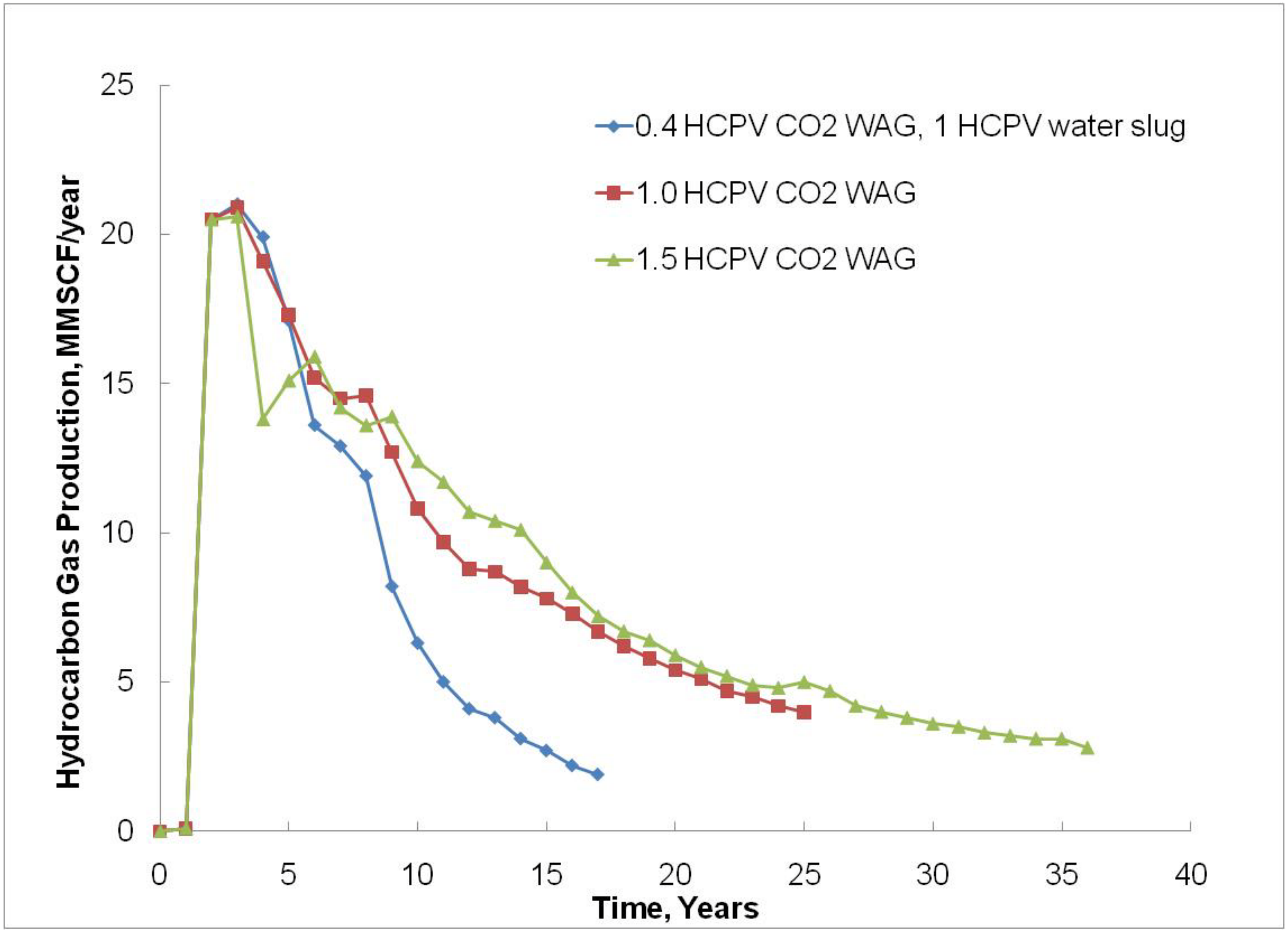


Figure 3-16 Incremental Hydrocarbon Gas Production for WAG Injection Scenarios (HCPVs)

Results will be discussed in greater detail in later sections, but it should be noted that modeling results show incremental oil production to increase with increasing CO_2 injection (Table 3-14), in agreement with the previously discussed field observations and the adopted definition of CO_2-EOR scenarios.

Table 3-14 Oil Recovery Efficiency (Percent of Original Oil in Place Recovered) as Estimated Based on CO_2 Prophet Screening Model Characterization of Three WAG Scenarios

CO_2-EOR Scenario	HCPV CO_2 Injected	Oil Recovery, % OOIP	Single Pattern Flood Duration (years)
Historical	0.4	11.6	17
Best Practices	1	17.4	25
1.5 HCPV CO_2 WAG Injection	1.5	20.9	36

Average fluid flow values for the proceeding set of model output plots are summarized in Table 3-15. Because flood duration differs between operational scenarios, values are reported on the average of the life cycle values (a per-pattern year basis) to facilitate direct comparison (all scenarios assume a 40-acre, 5-spot configuration).

Table 3-15 Summary of Model Results for Injection and Production Stream Fluid Flow Reported on a per Pattern Year Basis (40-Acre, 5-Spot Pattern Configuration)

Parameter	CO_2-EOR Operational Scenario			Units
	Historical	Best Practices	1.5 HCPV CO_2 WAG	
Water Injected	157.0	123.3	119.8	MSTB/(pattern-yr)
CO_2 Injected	106.4	180.9	185.5	MMscf/(pattern-yr)
Brine Produced	163.0	133.1	126.5	MSTB/(pattern-yr)
Crude Oil Produced	11.3	12.1	10.0	MSTB/(pattern-yr)
Total Liquids Produced	174.3	145.2	136.6	MSTB/(pattern-yr)
CO_2 Produced	63.9	127.7	147.6	MMscf/(pattern-yr)
HC Gas Produced	9.1	9.7	8.1	MMscf/(pattern-yr)
Total Gas Produced	73.0	137.4	155.7	MMscf/(pattern-yr)

Produced fluids are rarely treated at the production well or on an individual pattern basis, but generally are transported to a sattellite or central facility where fluids from multiple wells are combined and treated. As is described in the following section, the oil, hydrocarbon gas, CO_2, and brine production estimates developed for a single well pattern are used to develop life cycle performance estimates for those operations located downstream of the production well that processes flow from a number of producing wells.

Calculated Produced Fluid Loading to Tank Battery from 10 CO_2-EOR Patterns

It is assumed that produced fluid from ten CO_2-EOR patterns is collected to and processed at a single tank battery. Size, throughput, and quantity of unit process elements (equipment) have been determined based on the total fluid flow entering each process element. Resource requirements and emissions for each process element were then calculated based on equipment size, throughput, and estimated fluid properties.

Central tank batteries collect and process fluid that is produced from more than one production well. For purposes of this study, it has been assumed that each well pattern feeding a single tank battery initiates fluid injection at six-month intervals, thereby distributing predicted peak fluid injection and production over 4.5 years for the assumed 10-pattern tank battery. This assumption is in line with established rules of thumb for assumed (roll out) of CO_2-EOR patterns of approximately 10-20 percent of the total flood duration (approximately 3-6 years for the next-generation EOR scenario considered herein). Figure 3-17, 3-21, 3-22, and 3-23 illustrate the incremental production rates of total fluid, oil, water, CO_2 and hydrocarbon gas production from ten wells (as a function of time) when injections for each pattern are initiated at six-month intervals and all patterns are operated according to "historical" CO_2-EOR practices.

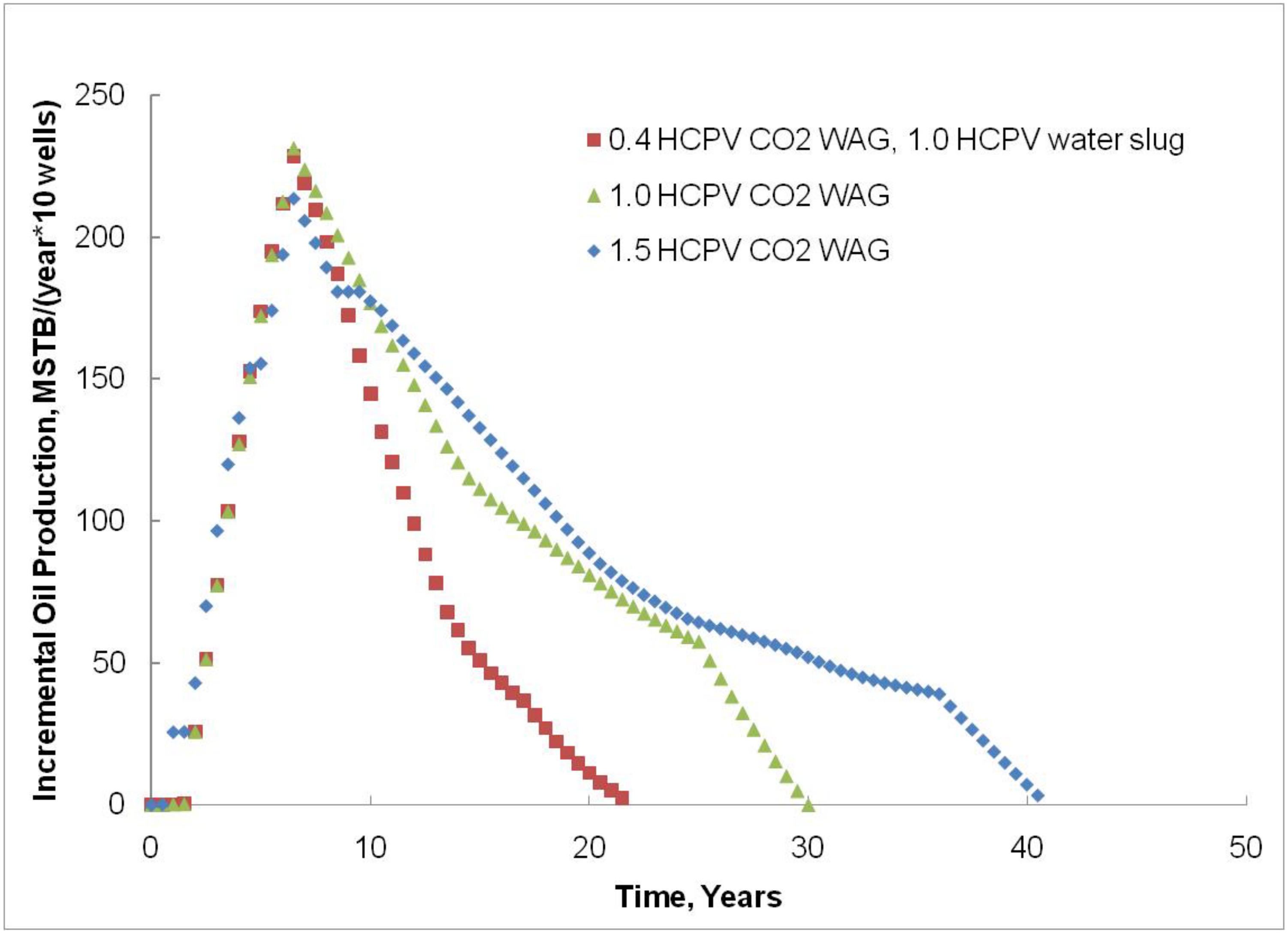


Figure 3-17 Incremental Oil Production Data from 10 Well Patterns Operated Under Three WAG Scenarios, with Injection Initiated at Six-Month Intervals for Each Pattern (MSTB/year)

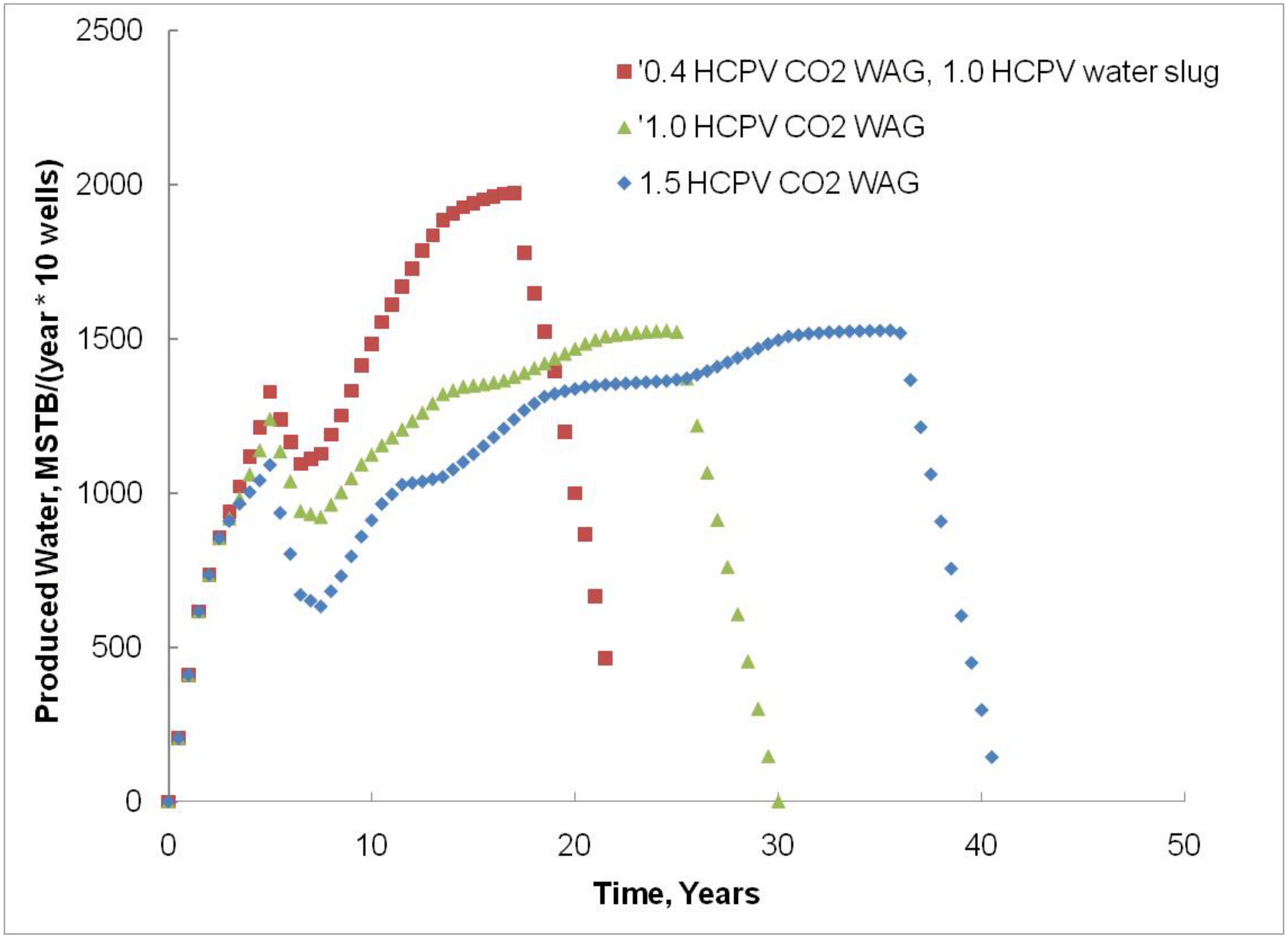


Figure 3-18 Incremental Water Production Data from 10 Well Patterns Operated Under Three WAG Scenarios, with Injection Initiated at Six-Month Intervals for Each Pattern (MSTB/year)

3.5 Phases of CO_2-EOR Facility Operation

Five phases of CO_2-EOR facility life have been considered:

- Site Evaluation and Characterization
- Facility Design and Construction
- Facility Startup and Operation
- Site Monitoring, Verification, and Accounting
- Facility Closure and Decommissioning

An attempt has been made to quantify material and energy flows associated with each of these phases of site operation, including resource demands, environmental emissions, and incremental hydrocarbon production.

3.5.1 Site Evaluation and Characterization

Enhanced oil recovery operations have taken place at sites where extensive disturbance to the subsurface has already occurred, where many penetrations into the target formation or confining strata are likely to exist. In many cases, the location of these wells is known, but it is also common to encounter abandoned fields or some very old fields with some abandoned wells that may or may not be locatable using traditional physical survey techniques. These penetrations could serve as a conduit for leakage of CO_2 from target formations, thereby decreasing CO_2-EOR effectiveness, decreasing overall CO_2 storage, and creating a hazard to human health. Therefore, it will be appropriate to review well files, regulatory maps and any available well log and surveying databases to locate these penetrations. It will also be prudent to conduct new reconnaissance land surveys, and to use ground or airborne magnetometry geophysical surveying techniques to locate wells that may be buried below the surface of the ground.

Following location of all wells, a determination must be made on whether or not an existing well can be used as a CO_2/water injection well or production well in proposed CO_2-EOR operations. In addition, to visual inspection, mechanical integrity testing of old wells may be performed to establish utility of existing wells for such applications. It will be necessary to establish baseline conditions above or adjacent to the target formation to facilitate future monitoring, verification, and accounting efforts. This may involve testing of the vadose zone, groundwater, or surface water to capture information on trends such as seasonal variations. Similarly, baseline geophysical surveys will likely also be required so that change can be observed during the injection phase or during post-injection MVA.

For purposes of this study, it has been assumed that one airborne geophysical/remote sensing survey is performed over the full surface area of CO_2-EOR activity, using light detection and ranging (LIDAR) and magnetometry to collect detailed site elevation and surface feature survey and screening for abandoned wells with no surface features, respectively. It has also been assumed that one legacy well that penetrates the target injection formation is located per square mile of survey area, and that that identified well is not reused in CO_2-EOR operations (U.S. EPA, 2008). Emissions associated with airborne and survey have been considered. It is assumed that abandoned wells located within the area of review are plugged to prevent CO_2 leakage from the target formation and prevent deterioration of overlying underground sources of drinking water (USDWs). Well plugging activities often include pulling lower portions of the well's (longstring) casing and cementing the abandoned well, but only cementing of the abandoned well is considered herein. The assumed number of legacy wells for which re-plugging is required corresponds to 0.0625 abandoned wells per 40-acre pattern. Values of abandoned well per pattern year are, then, estimated as 0.0625 divided by the number of years of operation per pattern, which varies as a function of CO_2-EOR scenario. Values are 0.00368, 0.00250, and 0.00184 abandoned wells per pattern year for historical, best practices, and 1.5 HCPV CO_2 WAG injection scenarios, respectively. Well-plugging diesel- fuel demand and emissions per pattern-year are reported in Table 3-16 for each operational scenario.

Table 3-16 Emissions Profile from Abandoned Well Plugging Operations Reported per 40-Acre Pattern Year Based on Operational Scenarios Described Herein

	Historical	Best Practices	1.5 HCPV CO_2 WAG Injection	Units
HC	1.05E-02	7.13E-03	5.25E-03	kg per pattern year
CO	8.34E-02	5.67E-02	4.17E-02	kg per pattern year
NO_X	1.57E-01	1.07E-01	7.86E-02	kg per pattern year
PM Total	4.00E-03	2.72E-03	2.00E-03	kg per pattern year
PM10	3.88E-03	2.64E-03	1.94E-03	kg per pattern year
PM2.5	1.20E-04	8.16E-05	6.00E-05	kg per pattern year
SO_2	2.25E-06	1.53E-06	1.12E-06	kg per pattern year
CO_2	33.35	22.7	16.7	kg per pattern year
Diesel Fuel	10.47	7.12	5.23	kg per pattern year
Diesel Fuel	3.30	2.24	1.65	gallons per pattern year

3.5.2 **Facility Design and Construction**

3.5.2.1 CO_2-EOR Facility Overview

The CO_2-EOR facility is considered to include all surface infrastructure elements associated with fluid injection and injectate transport, fluid production and transport, and produced fluid processing (including both liquids processing at tank batteries and gas processing plant to separate hydrocarbon gas and natural gas liquids from CO_2 recycle stream). Infrastructure elements associated with delivery of CO_2 to the oil field and those associated with transport of products from the site are not included within the study scope. A standard 5 spot well configuration with 40 acre pattern surface area has been assumed for all scenarios (with an injection: production well ratio of 1:1, as described in Table 3-8). In addition, it should be noted that a number of process elements have been assumed to be pre-existing. The pre-existing infrastructure elements have been excluded from consideration in this LCA.

3.5.2.2 Overview of Site Preparation for CO_2-Flood EOR

It has been assumed that the reservoirs for which CO_2 flood tertiary EOR would be considered are sites that have already undergone water flood secondary EOR operations. As such, many of the infrastructure elements and fluid processing/management components are assumed to be already present on site at the initiation of tertiary recovery site preparation. Those infrastructure elements and fluid processing components that are assumed to be pre-existing include:

- Water tanks
- Crude oil tanks
- Injection wells
- Production wells
- Produced fluid collection lines
- Water distribution lines

New process elements for which construction has been included are:

- CO_2 distribution lines
- Gas processing facility
- Recycle CO_2 compressors
- Tank battery vapor recovery unit

It is assumed that pre-existing secondary EOR injection and production wells can be reused for tertiary recovery operations, but that significant refurbishment will be required, in the form of well workover and recompletion, before fluid injection for tertiary recovery is initiated.

Because the site is assumed to be maintained up to the time of initiation of tertiary recovery operation as part of secondary EOR operations, site clearing and preparation are assumed to not be required. Similarly, necessary access roads and utility right-of-way are assumed to already be in place.

3.5.2.3 U.S. EPA UIC Injection Well Classes

EPA-promulgated rules establish Underground Injection Control (UIC) regulations (40 CFR 144.6) for protection of USDWs. In this regulation, five classes of wells have been established (with a sixth proposed) based on types of fluid injected, construction specifications, injection depth, and operating techniques (including related monitoring and verification activities). Class I wells are used for safe disposal of hazardous and nonhazardous fluids (both industrial and municipal wastes) into isolated formulations below the lowermost USDW, and are subject to stipulations of both the Safe Drinking Water Act and the Resource Conservation Recovery Act. Class II wells describe wells used for fluid injection in relation to conventional oil or natural gas production, enhanced oil or gas production, and storage of hydrocarbons that are liquid at standard temperature and pressure. Class III wells are used for solution mining. Class IV wells are specified in rare cases where hazardous or radioactive wastes are approved for injection into or above USDWs (typically groundwater remediation scenarios). Class V wells are those not covered in Classes I through IV; this class includes shallow, onsite disposal of nonhazardous fluids into or above USDWs such as floor and sink drain disposal. Class V wells have also been employed for experimental injection of CO_2 into reservoirs that do not contain significant quantities of hydrocarbons to demonstrate geologic sequestration of anthropogenic CO_2 (for example, in brine aquifers). A Class VI well type has been proposed by the EPA to formalize regulatory requirements of dedicated anthropogenic CO_2 disposal through geologic sequestration (GS) not associated with oil and gas production. In July 2008, the EPA published the federal requirements for CO_2 GS wells under the UIC Program, and public comment period ended on December 24, 2008. In August, 2009, Notice of Data Availability and Request for Comment (45 day public review and comment period) was issued. Final rule on Class VI wells has not yet been issued (U.S. EPA, 2009).

3.5.2.4 Overview of New Brine Disposal Well Construction

Excess brine is generated through CO_2-EOR activity, and it is assumed that new wells must be constructed for disposal of this byproduct stream. Saltwater disposal wells (SWD wells) may be constructed to inject into either non-commercial portion of the hydrocarbon-bearing reservoir, or a hydrocarbon bearing reservoir that is sufficiently distant from active CO_2-EOR operations as to not impact fluid production in active flood patterns (U.S. EPA, 2006). It is, therefore, assumed that excess brine is disposed of in a formation that is at the same depth as the formation targeted for CO_2-EOR activity. New well construction is carried out using drill rigs of scale and specification typical of those commonly used in oil field infrastructure placement in the Permian Basin.

Injection wells are designed to confine injected fluids to the targeted injection zone and prevent migration of injectate (e.g., brine) into penetrated USDWs. In CO_2-EOR operations, injection wells are drilled into oil bearing reservoirs capable of accepting injection fluids (i.e., CO_2, water) to stimulate oil production. Brine and acid gas disposal wells are also sometimes required to manage the production of unwanted fluids. Low- permeability confining zones overlie the injection target formation and restrict the upward migration of the injected fluids. Injection pressure must be controlled at the surface to avoid fracturing these confining zones. New injection wells are drilled and cased with steel pipe, and the steel casing pipe is cemented into place to prevent catastrophic well blowout and gradual migration of fluids to the surface or into USDWs. A typical injection well will also have a string of tubing located inside of the casing through which fluid injection takes place. Fluid is isolated to the targeted injection zone by a packer, which seals off flow into the innermost casing and facilitates leak detection. The following sections provide more detailed consideration of brine-disposal injection-well design and construction. In cases of new well construction, drilling operations, casing material (all wells are assumed to be cased, as compared to open-hole, completions), cement, and associated well components have been considered in the life cycle environmental inventory. As described elsewhere, some old or abandoned wells may be acceptable for repair or reuse in newly commissioned CO_2-EOR operations.

3.5.2.5 Estimation of Brine Disposal Well Injectivity and Storage Capacity

Lyons (1996) reports a range of typical injectivity index values between 8 and 15 barrels per (day-net feet). Using this range and the target formation net thickness of 76 feet gives a range of between 600 and 1140 barrels per day. A survey of water injection practices near the Waste Isolation Pilot Plant in southeastern New Mexico (US DOE, 2003) reports that of 39 salt water disposal well (SDW) injection wells near the facility, the average injection rate was 1,250 barrels per day per well. A report by the Texas Water Development Board and the Texas Bureau of Economic Geology cites a mean injection rate of 10 gallons per minute (approximately 340 barrels per day) in the Permian basin (calculated based on estimated formation and fluid properties, and a maximum surface injection pressure gradient of 0.5 psi/ft to top of injection interval).

A robust resource for data on the cumulative capacity of brine disposal wells in the Permian Basin was not identified. One report considering the storage capacity of wells near the U.S. DOE Waste Isolation Pilot Plant cited cumulative injection volume into David Ross AIT Federal Number 1 of 1.3 x 10^6 cubic meters (1.3 billion liters, or 8.2 million barrels, and assuming a brine density of 1.1 kg/liter, 1.5 million metric tonnes). Dedicated disposal wells in Ohio are reported to have capacities of up to 20 million tonnes of injectate—a capacity significantly larger than referenced for the New Mexico well. A brine-disposal cumulative storage capacity of 1.3 billion liters is assumed, but this characterization would benefit from more robust and geographically appropriate sources of data; this is noted as a data limitation. The capacity and injectivity estimates reported herein have been employed to estimate the number of brine-injection wells that will be required to accept excess brine produced as a result of CO_2-EOR activity.

3.5.2.6 **Estimation of Brine Injection Wellhead Pressure**

Brine-injection well head pressure, the pressure to which brine must be pressurized to maintain fluid injectivity, is estimated by back-calculating from maximum bottom hole pressure. Wellhead pressure is calculated as the bottom hole pressure minus allowable static fluid pressure plus the sum of all frictional losses through the well. Static water pressure is estimated by multiplying the depth to formation midpoint (5826 + 76/2, or 5864 feet) feet by an assumed hydrostatic gradient of brine of a density of 64.8 lbs/ft3 (0.45 lb/psi) to get 2,638 psi. Pressure drop in the tubing is relatively small given the prescribed tubing internal diameter of 2 7/8 inches—on the order of 10 psi per thousand feed of tubing. This corresponds to a pressure drop of approximately 60 psi along the full tubing length. Applying the default fracture gradient of 0.5 psi/ft to the top of the injection reservoir that is prescribed by the Texas Railroad Commission, the associated maximum bottomhole pressure would be 2,914 psig; taking into account previously calculated hydrostatic pressure and pressure drop, this corresponds to a maximum wellhead pressure of 335 psig. Because injection wells are typically operated at or near the maximum permitted injection pressure, a brine injection wellhead pressure (and the pressure to which produced brine must be pressured before injection into the reservoir) of 300 psi is assumed for this study. Injection at higher pressure may be an option, but the operator would first need to demonstrate that the formation and infrastructure elements are capable of accommodating higher pressure (brine disposal at pressures greater than the fracture threshold is typically permitted if the injection well passes a fracture step rate test). It is worth noting that, throughout the history of CO_2-EOR in the Permian Basin, fields have safely accommodated higher surface injection pressure than that specified by the default fracture gradient, whereas operations in other basins have not (Melzer, 2010).

3.5.3 **Well Drilling and Completion**

Oil production, injection, and fluid disposal wells are drilled using similar technology and equipment. Modern drill rigs are designed to perform four main tasks:

- Produce and transfer power
- Hoist equipment used in well completion, including drill string, casing, and tubing used for fluid transfer
- Rotate the drill string and bit to drill the well bore

- Circulate drilling mud that is used to remove cuttings from the drilling front and maintain pressure in the well bore

Diesel fuels are the most common source of power used in drilling operations. Diesel is combusted in large engines to drive electric generators that produce electric power that is used by electric motor-driven elements of the mechanical system (including drawworks that are used for hoisting, the turntable that is used to turn the kelly to rotate the drill string and bit, and mud pumps used to circulate drilling mud to the bit). For more detailed consideration of drilling operations, the interested reader is directed to any of a number of texts dedicated to the topic.

Consideration of new well construction in this report is limited to the following elements:

- Delivery of drill rig elements to the well site, including power station, mechanical systems, drill string, dog house, steel casing, derrick, and substructure (includes diesel used to deliver drill rig elements, particulate emissions from off-road travel, and 12,000 gallon diesel storage tank emissions)
- Assembly of drill rig elements
- Operation of drill rig (diesel consumption, cooling water use, mud, cuttings from drilling operation)
- Break-down of drilling elements
- Construction of permanent well elements, including steel used in casing, cement used to secure and seal casing, tubing used in operation, and water used in producing cement)

3.5.3.1 Drill Rig Description

Sub-6,000 foot rigs generally employ sub-500 horsepower rigs (Land Rig Newsletter, February 2009), but a cursory review of rigs operating in the Permian Basin play suggest that a rig with drilling capacity of 550 horsepower may be appropriate. Performance of the drilling rig is estimated using rig number 472 (http://patdrilling.com/pdf/rigs/472.pdf), which operates with two Caterpillar 3408 engines (475 HP each). Specifications for major rig elements are summarized in Table 3-17; additional detail is provided in
Appendix F.

Table 3-17 Specifications Used to Characterize Drill Rig

Rig Element	Equipment Description
Power plant	(2) Caterpillar 3408 engines (475HP each)
Drawworks	National 370-M (550HP) 1 1/8” drill line, Parmac 22-SR auxiliary brake
Mast	DSI 132’ w/ 322,000# capacity on 8 lines construction
Substructure	DSI 14’ box KB 13’ 6” Rotary beam clearance 9’ 4”
Mud Pumps	(2) Continental Emsco DB-550 (550HP each) duplex pumps (1) Powered by a Caterpillar 379 engine (1) Powered by a Caterpillar 353 engine
Rotary table	Gardner Denver (17 1/2”)
Drill pipe	4 1/2” drill pipe

3.5.3.2 Wellbore Design

The wellbore consists of three primary components: casing, cement, and the wellhead assembly. The wellbore casing is a set of steel pipes that are cemented in place during the construction process in order to stabilize the wellbore, prevent caving into the wellbore, isolate near-surface formations to prevent fluid contamination into USDWs, seal off permeable formations from cross-flowing into others, and to facilitate maintenance of fluid pressure during well operation. Sometimes as many as four to five casing strings are emplaced with the smallest diameter one, called the long-string, set to the maximum depth of the well (Melzer, 2010). A wellhead assembly is located at the surface termination of a wellbore, and includes functionality to install casing hangers during well construction, hang the production (or injection) tubing, and install the "christmas tree" and surface flow control facilities in preparation for the production phase of the well. Cement used to secure well casing and prevent cross-flow of pressurized fluids has traditionally been made from a variety of ingredients, including Portland cement, fly ash, and clay admixtures. These cements have been required to perform in highly acidic fluid environments, much more acidic than those expected with CO_2 injection.

Injection well design is assumed to be the same as that used for CO_2 injection in the Frio Sandstone Formation as defined by Hovorka and colleagues (2003). Prior to initiation of drilling activities, 14-inch conductor casing is installed to approximately100 ft in a hole of 17½ inches in diameter. After setting the conductor pipe, the surface hole is drilled to a depth of approximately 2,600 ft at a diameter of 12¼ inches, and a $9^5/_8$-inch surface casing is cemented along the full length. The injection well is completed with a 5½-inch production casing string (also cemented between outside of casing pipe and $7^1/_8$ inch drill hole wall along the deep-section length of 5,826 feet), and 2⅞ -inch tubing installed inside the protection casing through which injected fluid is conveyed to the target reservoir.

Table 3-18 Specifications Used to Characterize Injection Well: Casing, Injection Tubing, and Drill Pipe

Tubular	Depth (ft)	Nominal Size (inches)	Weight (lb/ft)	Grade	Estimated mass of steel (short tons)	Number of 30 ft. segments	Estimated number of tri-axle truck loads
Conductor	1–100	14	54.6	A-36	54.6	2	1
Surface casing	0–2,600	9⅝	36	J-55	45	87	3
Protection casing	0–5,826	5½	15.5	J-55	45	195	3
Injection tubing	0–5,826	2⅞	6.5	API N-80	19	195	1
Drill Pipe	0–5,826	5	14.87	API Spec 5D	43	195	3

3.5.3.3 Cementing Operations

Cement is pumped ("squeezed") from the bottom of the hole using a one-way valve between the external wall of casing pipe and the drilled well hole. This affords additional protection to prevent gradual leakage of deep fluids from the injection target formation to overlying drinking water aquifers and the surface, as well as providing isolation of the pressured formations from anything but the wellbore. The volume of cement slurry required to cement the casing was estimated based on standard recipe for API Class A cement, requiring 5.2 gallons of water per 94-lb sack of dry cement. Assuming standard porosity of dry cement of 52 percent (Chilingar et al., 1989), the resulting slurry has a density of 1.18 ft^3/sack of cement. Volume of the cement is estimated to be approximately 1,722 ft^3 (49 m^3)—the space between each casing and the drill hole wall or the space between each casing and the inner wall of the next larger diameter concentric casing pipe. Based on well specifications provided in Table 3-18, an estimated 1,466 sacks of cement (69 short tons or 62.5 metric tonnes of cement) and 8,500 gallons of water (32 short tons or 29 metric tonnes of water) are required.

3.5.3.4 Rig Delivery and Rig Up

Resource demands and emissions related to delivery of drilling rig elements are characterized by estimating the number of heavy-rig truck round trips to deliver all drill rig elements, assuming a round trip distance of 50 miles. The rig is assumed to be of modular design, with each module delivered to the well site in a single tractor trailer load. Based on drill rig layout blueprints available online (Integrated Drilling Equipment, 2004), an estimated 25 skid-mounted rig elements are delivered by a single tractor trailer. This count is assumed to include drill pipe required for drilling, but not other tubular elements of the wellbore casing. Based on estimates listed in Table 3-18, an additional eight round trips will be required to deliver well casing and tubing. Delivery of drilling mud, Portland cement, and fresh water to the well site are not considered. Assuming a fuel efficiency of 6.21 miles per gallon and a round trip distance of 50 miles, approximately 8 gallons of ultra-low sulfur diesel fuel are used per round trip. An estimated 48 50-mile round trips are required to deliver rig elements and well components, using approximately 386 gallons of diesel fuel. It is assumed that this volume of diesel fuel includes removal of rig elements after drilling operations are complete.

Emissions from diesel fuel combustion associated with tractor trailer delivery of rig elements are calculated based on emissions levels at low altitude (Midland-Odessa, TX elevation of 2,782 feet [848 meters]) for heavy-duty diesel powered vehicles of model years after 2001 as specified in EPA AP-42, Appendix H, and reported in Table 3-19.

Table 3-19 Emissions Estimate for Delivery of Rig Elements to Drilling Site

Pollutant	Emissions Factor	Estimated Emissions (kg)	Source
Non-methane hydrocarbon	2.1 g/mile	5.04	U.S. EPA AP-42
Carbon monoxide	10.320 g/mile	24.8	U.S. EPA AP-42
NO_X	6.490 g/mile	15.6	U.S. EPA AP-42
CO_2	10,084 g/gallon diesel	3,899	U.S. EPA "Emissions Facts" (2009)

3.5.3.5 Operation of Drill Rig

Operational parameters for the drill rig specified above with two 475-horsepower diesel engines are summarized in Table 3-20.

Table 3-20 New Well Drilling Rig Performance Specifications

Parameter	Value	Units
Drilling time	10 days of continuous operation (504)	Days (hours)
Rig power plant	2 x 475	No. engines x horsepower
Engine load factor	0.75	unitless
Break-specific fuel consumption	0.367	lb/hp-hr
Emissions performance	Meets Tier 2 emissions standards	-

A California Air Resources Board document reports an average drill rig diesel demand of 1.55 gallons per foot drilled (with a reported range of between 1.4 and 1.7 gallons per foot). Assuming that the reservoir is drilled to the bottom of the target reservoir (5,902 feet), an estimated per-well diesel demand of approximately 9,150 gallons is calculated. An alternative calculation method calculates fuel demand per well based on the number of diesel engines used in a drill rig, brake-specific fuel consumption estimates of each engine, and the estimated number of hours of rig operation per well drilled. Two 475-horsepower engines are specified in the rig package, and during the period of operation, it is assumed that both engines are in operation at a capacity factor of 0.75. The length of operation is estimated based on a reported spud-to-take-down period of 10 days. Using a brake-specific fuel consumption value of 0.367 lb/hp-hr, a drill rig diesel fuel usage rate of 8,964 gallons per well drilled is estimated.

Combustion emissions from the drill rig are estimated based on the EPA Office of Transportation and Air Quality document entitled *Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling--Compression-Ignition* (2004). Rig combustion emissions per well drilled were estimated based on methodology outlined in the EPA report, and results are shown in Table 3-21.

Table 3-21 Emissions Estimate for Drill Rig Operated in New Well Construction for Brine Disposal

Constituent	Metric Tonnes (Short Ton) per Well Erilled
Total Hydrocarbon	0.0285 (0.0315)
CO	0.131 (0.144)
NO_X	1.05 (1.16)
PM Total	0.0221 (0.0243)
PM_{10}	0.0214 (0.0236)
$PM_{2.5}$	0.000662 (0.000730)
CO_2	90.7 (100)
SO_2	0.139 (0.153)

Drilling Mud. Drilling fluid is employed during well-drilling operations for drill bit lubrication and cooling, removing cuttings from the drilling front, and borehole stability. It is assumed that water-based mud is used in all drilling operations. The composition of the assumed drill mud is reported in Table 3-22.

Table 3-22 Range of Water-Based Drilling Mud Composition as Reported by Eaton and Colleagues (1981), and Average Composition Assumed for Drilling Mud Usage Calculations

Component	Concentration Range, kg/m^3 (lb/bbl) per Eaton et al. (1981)	Average Mud Concentration (value assumed for this study), kg/m^3 (lb/bbl)
Water	570 to 970 (200 to 340)	770 (270)
Bentonite	43-86 (15-30)	64.5 (22.5)
Lignosulfonate	5.7 to 29 (2 to 10)	17 (6)
Lignite	2.9 to 17 (1 to 6)	10 (3.5)
Sodium Hydroxide	2.9 to 14 (1 to 5)	8.5 (3)
Barite	0 to 1430 (0 to 500)	715 (250)

Based on an assumption that the volume of drill mud required is 1.5 times that of the total drilled volume of 3,100 ft^3 (88 m^3) per well, the following total mass of mud components is estimated. The mass of mud assumed to be managed as waste is estimated as the sum of all solids plus 50 percent water, by mass (assuming 50 percent on-site dewatering before disposal).

Table 3-23 Estimated Mass of Drilling Mud and Mud Components, and Estimated Mass and Composition of Used Mud for Disposal

Component	Estimated Mass of Water-Based Mud Required to Drill a Single Well, Metric Tonne (Short Ton)	Estimated Mass of Dewatered Used Mud Managed as Waste Following Drilling of a Single Well, kg (lb)
Water	102 (112)	51 (56)
Bentonite	8 (9)	8 (9)
Lignosulfonate	2 (2)	2 (2)
Lignite	1 (1)	1 (1)
Sodium Hydroxide	1 (1)	1 (1)
Barite	94 (104)	94 (104)
Total	209 (230)	158 (174)

Solids Management. Used drilling mud that is produced from drilling operations is assumed to be directed to solids-control equipment consisting of a shale shaker and desander/desilter to remove drill cutting from the circulating mud. Cleaned mud is then returned to the mud pit for recirculation into the drill hole, and separated cuttings are characterized and disposed of appropriately (non-hazardous solids may be disposed of onsite, but solids exceeding Federal and state threshold concentrations of constituents of concern will require disposal at an approved facility). It is also assumed that solids generated as a result of drilling operations have concentrations below such thresholds and all solids are disposed of onsite. The volume of total drilling solids is assumed to be the same as the total well-hole volume, which is estimated as the sum of volumes of the holes drilled for conductor, surface casing, and production casing to be approximately 3,100 ft^3. At the end of drilling operations, it is assumed that drilling mud is dewatered, characterized, and disposed of in accordance with Federal and state requirements. Separated water will be sent to tank battery water storage and either injected as part of CO_2-EOR WAG injection or disposed of in adjacent brine disposal well.

Drilling Mud Degassing CH_4 Emissions. Drilling fluid employed during well drilling operations for drill bit lubrication and cooling, removing cuttings from drilling front, and pressure maintenance accumulates gas at pressure and degasses when removed to atmospheric pressure. These gases are typically very small in volume and, as such, are vented, constituting atmospheric emissions of methane and other hydrocarbons. If larger volumes of hydrocarbon gasses are encountered, flaring is carried out. API GHG emissions methodology reports default factors for total hydrocarbons (THC) and methane emissions per day of active drilling. Degassing emissions from water-based muds are reported to be 881.84 lb THC per drilling day (0.4 metric tonnes per drilling day) and 574.30 lb CH_4 per drilling day (0.2605 metric tonnes CH_4 per drilling day) (API, 2009). Non-methane hydrocarbon emissions are, therefore, 307.53 lb non-methane hydrocarbons per drilling day (0.1395 metric tonnes non-methane hydrocarbons per drilling day). Using the aforementioned 10-day drilling time, emissions per well drilled are estimated at 2.605 metric tonnes of CH_4 and 1.395 metric tonnes of non-methane VOC.

Existing Well Recompletion Prior to CO_2-EOR Flooding. Recompletion of wells can be accomplished using a variety of techniques requiring a range of surface and down-hole equipment and activities. Because of the highly variable nature of workover activity associated with well recompletion for CO_2-EOR, it is not possible to develop a single characterization that appropriately represents all cases. For purposes of this study it has been assumed that reworking of existing waterflood production and injection wells for CO_2-EOR (the first rework following waterflood operations and prior to initiation of CO_2-EOR operations) requires pulling and replacing tubing string and pumping. This activity is assumed to be performed with a workover rig, which is smaller than a drilling rig and has lower associated power requirements and emissions.

In addition to the workovers performed on all wells before initiation of CO_2-EOR operations, it is assumed that all wells (one injection and one producing well per pattern) will require workover during CO_2-EOR flood operations at a rate of one workover per four years (this workover rate is specified in by the National Petroleum Council [Bailey and Curtis, 1984]).

Table 3-24 Estimation of Number of Well Workovers Required over the Life of CO_2-EOR Pattern Operations for Each Operational Scenario

CO_2-EORScenario	Years of Operation of Single-Well Pattern	Number of Initial Workovers per Pattern	Number of Maintenance Workovers Required over Operational Lifetime (excludes initial workover)	Total Number of Workovers Required Over Life of CO_2-EOR Pattern Operation
Historical	17	1 (x 2)	4 (x 2)	10
Best Practices	25	1 (x 2)	6 (x 2)	14
1.5 HCPV CO_2 Injection	36	1 (x 2)	8 (x 2)	18

Assumptions that have been made in characterizing workover activities are summarized in Table 3-25.

Table 3-25 Summary of Assumptions Made to Characterize Well Workover Prior to Initiation of CO_2-EOR Flooding

Workover Parameter	Value	Units
Workover rig horsepower	475	hp
Workover rig load factor	0.75	unitless
Assumed average workover duration	36 (3 days @ 12 hours/day)	hours
Environmental performance	Meets Tier 3 emissions standards	-
Brake-specific fuel consumption	0.367	Lb/hp-hr
Number of workovers per flood pattern	2	Workovers/pattern

Based on these assumptions, a total diesel fuel demand per workover of 8,483 liters (2,241 gallons) has been estimated. Emissions associated with consumption of this volume of diesel in the specified workover rig are reported in Table 3-26.

Table 3-26 Emissions and Diesel Usage from Workover Rig Operation

Constituent	Emission from Single Well Workover prior to Initiation of CO_2-EOR	Units
HC	2.14E-03 (2.36E-03)	Metric tonnes (short tons)
CO	1.70E-02 (1.88E-02)	Metric tonnes (short tons)
NO_X	3.21E-02 (3.53E-02)	Metric tonnes (short tons)
PM_{Total}	1.66E-03 (1.82E-03)	Metric tonnes (short tons)
PM_{10}	1.61E-03 (1.77E-03)	Metric tonnes (short tons)
$PM_{2.5}$	4.97E-05 (5.47E-05)	Metric tonnes (short tons)
CO_2	6.80 (7.50)	Metric tonnes (short tons)
SO_2	1.04E-2 (1.15E-2)	Metric tonnes (short tons)
Low Sulfur Diesel	2,545 (672.3)	Liters (Gallons)

In addition to direct emissions from diesel fuel combustion to power the workover rig, indirect emissions from well workover include particulate emissions from traffic on unpaved lease and public access roads, emissions from rig delivery and workover operations, and fugitive emissions from the well occurring during workover operations. Fugitive emissions associated with workover operations were estimated using the US. EPA AP-42 emissions factor of 96 scf of CH_4/workover (U.S. EPA, 1995).

Table 3-27 Estimate of Methane Fugitive Emissions from Well Workover over the Life of a Single Well Pattern for Each Operational Scenario Under Consideration

CO_2-EOR Scenario	Number of Workovers per Well pattern over Lifetime of Single EOR Flood	Fugitive Methane Emissions from Workovers over Lifetime of Single EOR Flood Pattern (scf Methane/Pattern)	Mass of Methane, kg (lbs) per EOR Pattern[a]
Historical	6	576	10.9 (24.02)
Best Practices	10	960	18.17 (40.03)
1.5 HCPV CO_2 WAG	14	1,344	25.44 (56.05)

[a] *Based on 0.0417 lb/ft^3 at 20 °C, 1 atmosphere*

Unpaved Road Dust Emissions and Wet Suppression. It has been assumed that particulate emissions from road traffic on unpaved roads at the CO_2-EOR flood site are controlled using "wet suppression" practices—applying water to the road surface to keep it wet. In contrast, methods of "chemical stabilization" require chemical application to modify the physical properties of the unpaved road surface to decrease particulate emissions. Water application conglomerates particles on the unpaved road surface and reduces availability of small particles to become suspended; the effectiveness of this method decreases as surface moisture content decreases. The required frequency of water application is a function of factors such as the amount of water applied per unit surface area at each application, speed and frequency of road traffic between applications, and site meteorological conditions that influence water evaporation rate.

Estimation of Site Operation Particulate Emissions. The following empirical expressions provided by the U.S. EPA (EPA, AP-42: Section 13.2.2) on emissions from unpaved roads (1995) were used to estimate the quantity in pounds (lb) of size-specific particulate emissions from an unpaved road, per vehicle mile traveled (VMT). For vehicles traveling on unpaved surfaces at industrial sites, emissions were estimated using the following equation:

(2a)

and, for vehicles traveling on publicly accessible roads, emissions have been estimated using the equation:

(2b)

where

k, *a*, *b*, *c*, and *d* = empirical constants (Reference 6) provided in Table 3-28
E = size-specific emission factor (lb/VMT)
s = surface material silt content (percent)
W = mean vehicle weight (tons)
M = surface material moisture content (percent)
S = mean vehicle speed (mph)
C = emission factor for 1980s vehicle fleet exhaust, brake wear. and tire wear.

Table 3-28 Empirical Constants Used to Estimate Particulate Emissions from Unpaved Roads

Constant	Industrial Roads (Equation 1a)		Public Roads (Equation 1b)	
	PM-2.5	**PM-10**	**PM-2.5**	**PM-10**
k (lb/VMT)	0.15	1.5	0.18	1.8
a	0.9	0.9	1	1
b	0.45	0.45	-	-
c	-	-	0.2	0.2
d	-	-	0.5	0.5

Finally, emissions were adjusted to the region based on the average fraction of the year with days with precipitation events using the following equation:

(3)

A map provided by the EPA sets the number of days with precipitation events in the Permian Basin at approximately 60 days. Based on this method, 10-micron particulate emissions are estimated to be 631 lb over the life of one well pattern, and 2.5-micron particulate emissions are estimated to be 28.3 lb over the life of one well pattern. This corresponds to a total particulate emissions rate of 659.3 lb over the life of one well pattern. Assuming that this dust emission rate is appropriate for all operational scenarios, the particulate emission rates per well pattern year are reported in Table 3-29.

Table 3-29 Summary of Particulate Emissions (Controlled) from Construction Traffic on Unpaved Roads, and Dust Suppression Water Consumption Rate per Pattern Year

Parameter	Historical	Best Practices	1.5 HCPV CO_2 WAG Injection	Units
PM10	61.70	33.96	22.43	kg/(pattern-yr)
PM2.5	2.76	1.52	1.01	kg/(pattern-yr)
Total Particulates	64.46	35.48	23.44	kg/(pattern-yr)
Water Consumption for Dust Suppression	14,389	7,920	5,231	kg/(pattern-yr)

Estimation of Unpaved Dust Suppression Water Requirements. Based on an assumed unpaved road length of 0.5 miles (805 meters) per pattern, road width of 10 feet, water application intensity of 0.2 liters per m^2, time between application of 2 hours, average potential evaporation of 0.23 mm/hr, average number of days per pattern during which dust suppression is required of 60 days/pattern, and a dust suppression control efficiency of 69 percent, approximately 147 metric tonnes of fresh water are consumed per well pattern (U.S. EPA, 2004). Assuming that this water demand estimate is appropriate for all operational scenarios, fresh water requirement per well-pattern year was calculated and is reported in Table 3-29.

3.5.3.6 Fluid Distribution and Gathering Lines

CO_2 Distribution System. The CO_2 distribution system is analogous in scale and infrastructure makeup to the gathering systems used for natural gas, with CO_2 distributed from a central "hub" to the CO_2 injection site through a system of smaller pipelines (ARI, 2006). Typical pipeline size (diameter and wall thickness) is a function of the maximum injection requirements for a site (Melzer, 2010).

- 4" pipe (CO_2 rate less than 40MMcf/d)
- 6" pipe (CO_2 rate of 40 to 60 MMcf/d)
- 8" pipe (CO_2 rate of 60 to 80 MMcf/d)
- Pipe greater than 8" diameter (CO_2 rate greater than 80 MMcf/d)
- Distance from the CO_2 "hub" (transfer point) to the oil field
- From hub to oil field, the distance is assumed to be 10 miles.

As a means of determining appropriate pipe schedule to transport compressed CO_2, required CO_2 distribution line wall thickness was estimated based on the simplified equation for stainless steel pipe and tubing pressure rating, as provided by Aalco Metals Limited (2009).

$$thickness = \frac{PD}{2SE} \tag{4}$$

where

P = pipe internal design pressure, thousand psi (kpsi), (2.2 kpsi)
D = pipe outside diameter, inches (assuming 4 inch nominal pipe, with 4.5 inch OD)
S = stress value for material (in tension) as a function of operating temperature, kpsi (for A312 steel tubing operating between -325 and 100 °F, a stress value of 16.7 kpsi is reported)

E =manufacturer-specified quality factor (for ASTM A312 TP 316L seamless piping, E = 1.0)

Assuming a maximum distribution pressure of 2,200 psi, nominal steel piping of A312 steel (seamless) requires a wall thickness of 0.296 inches, and ANSI schedule 80 piping with wall thickness of 0.337 inches is specified.

A report by the U.S. EPA entitled Geologic *CO_2 Sequestration Technology and Cost Analysis* (2008) assumes 4.5 miles of four-inch pipe and 4.5 miles of 6-inch pipe are required to accommodate CO_2-EOR field operations over a developed area of 20 square miles; this length of pipeline is approximately the square root of the development area. Based on this observation, it is assumed that the length of 4 and 6 inch CO_2 distribution pipeline can be approximated to be the square root of the developed CO_2 study area.

Table 3-30 Estimation of Mass of ANSI Schedule 80 Stainless Steel Pipe Required per 10 Well Patterns for CO_2 Distribution

CO_2 Distribution Element	Pipe Thickness, Inches (ANSI Schedule)	Unit Weight of Piping		Estimated Mass of Pipe, Metric Tonnes (Short Tons)	
		lb/ft	lb/mile	per 20 square miles (based on 4.5 miles of each size pipe)	per square mile
4" stainless steel pipe	0.337	14.9	78,672	161 (177)	8.0 (8.85)
6" stainless steel pipe	0.432	18.6	151,008	308 (340)	15 (17)
Total Mass	-	-	-	469 (517)	23 (25.8)

Based on this mass of steel, a proprietary life cycle emissions profile for stainless steel (80 percent recycled) was applied to estimate emissions associated with production of these steel CO_2-EOR infrastructure elements. Emissions associated with installation of CO_2 distribution pipeline have been neglected.

Brine Distribution Lines. Pipelines used for brine distribution to EOR injection wells from tank batteries are assumed to be pre-existing to CO_2-EOR activity because these infrastructure elements are required for secondary water flood EOR that would have already taken place at sites where tertiary CO_2-EOR activity is being initiated. As such, inventory of resource demands and emissions for brine distribution infrastructure are considered to be negligible.

3.5.4 Gas Processing Facility Construction

Construction of the gas processing facility is characterized based on an estimate of the mass of steel and concrete of which the gas processing facility is composed. A large LNG processing facility located in Qalhat, Oman, with a design throughput of 160 Bcf/year (about 438 MMcf/day) (EIA, 2009) was constructed with an estimated 10,000 tons of steel, and 100,000 cubic meters of concrete (concrete for plant foundation) (Energy Dynamics, 2009). Based on these reported values, plant construction has standard construction material requirements of 22.8 tons of steel per MMcf/day and 228 cubic meters of concrete per MMcf/day. This corresponds to estimated steel and concrete requirements, for a gas processing facility designed to handle 45MMcf/day (plant size assumed for this study), of 1,027 metric tonnes of steel and 10,266 cubic meters of concrete. Material and energy requirements and emissions associated with production of this amount of construction material were calculated using life cycle profiles not detailed herein; results are detailed in Table 3-31. It is recognized that a LNG plant differs in design and construction significantly from a natural gas processing plant. However, construction material upstream emissions are expected to contribute a relatively small amount to environmental emissions as compared to plant operation, such that using these numbers to characterize natural gas processing plant construction is considered to be adequate. This is noted as data limitation.

Table 3-31: Estimate of Emissions Associated with Gas Processing Facility Construction Materials Upstream Profile

Pollutant	Mass of Pollutant, Metric Tonnes (Short Tons)
CO_2	8,946 (9,861)
CO	14 (16)
Particulate (total)	113 (124)
Methane	0.15 (0.17)
Nitrogen oxides	23 (25)
Sulfur dioxide	33 (37)
VOC	0.38 (0.42)

Water required to produce this mass of construction materials is estimated to be approximately 17.4 million liters (66 million gallons).

3.5.5 **Facility Operation**

Characterization of the CO_2-EOR facility operations phase is based on modeled flood performance under historical, best practices, and next-generation scenarios designed previously. Fluid production rates and compositions estimated as a result of specified CO_2 and brine injection schedules serve as the basis from which infrastructure size, throughput, process energy input requirements, and emissions were estimated. Four major areas of operation were considered based on these estimated process flows:

- Fluid injection operations
- Fluid production operations
- Tank battery (liquid processing operations)
- Gas processing facility and compression operations

It should be noted that the scope of this LCA as described above does not include bulk CO_2 transport to the EOR reservoir site from the CO_2 source. Each of these four areas of operation is considered in more detail below.

3.5.5.1 Pattern-Year Concept

Total gate-to-gate emissions associated with CO_2-EOR activity can be estimated through a relatively straightforward summation of emissions from individual activities contributing to the overall life cycle profile. However, relating the activity and material flows from a single well pattern to larger-scale unit processes (e.g., gas processing facility) must be carried out with careful attention to units to ensure that emissions are appropriately accounted for. To do this, the simple concept of the pattern-year is introduced. Pattern-year describes the number of years of operation of each CO_2-EOR well pattern. As described earlier, the length of CO_2 WAG injection for each scenario varies as a function of the total volume of fluid (CO_2 and water) injected and injection rate. For the historical, best practices, and 1.5 HCPV CO_2 WAG injection scenarios as defined in this report, each pattern flood operates for 17, 25, and 36 years, respectively. Operation of one well pattern as a historical CO_2-EOR flood corresponds to 17 pattern years. Each tank battery is assumed to accept fluid from 10 well patterns for the life of those patterns, such that a single tank battery under the historical CO_2-EOR scenario accepts 170 pattern-years of produced liquids. When operated under a 1.5 HCPV CO_2 WAG scenario, the tank battery accepts 360 pattern-years of produced fluid. Finally, a well pattern operated under the historical CO_2-EOR scenario produces an average of 73.0 MMscf of total gas per pattern year (0.2 MMscf per pattern day) over the pattern flood lifetime. At this production rate a gas processing facility accepting 45 MMscf of total gas per day is capable of accepting gas from approximately 225 well patterns operated under the historical CO_2-EOR scenario. Normalizing performance to the pattern-year for each operation scenario allows unit operations performing at different scales to be described in common terms, and simplifies accounting of emissions and other material/energy flows.

3.5.5.2 CO2-EOR Fluid-Injection Operations

Water Supplied to EOR Field

It is assumed that water injected into the producing pattern as part of a WAG CO_2-EOR injection is provided by water produced from EOR activity within the oil field (stored produced brine from adjacent EOR tank batteries). Validity of this assumption has been evaluated by comparing the total volume of brine produced from each injection scenario with the total volume of brine required to satisfy the WAG injection. These data (Table 3-32) show that, for all three scenarios, the production of brine is greater than the demand for brine over the lifetime of the CO_2-EOR operations except for the end (chase water) period. This justifies that, in the case of the average basin considered in this report and under the assumed operational scenarios, CO_2-EOR operations can be assumed to be self-sufficient—requiring no water delivery from out-of-field surface or groundwater sources. The excess water produced through CO_2-EOR operations will require management. It is assumed that brine that is produced in excess of that which is used in the CO_2-EOR WAG or post-injection water slug is injected for disposal at a location adjacent to the EOR reservoir, but outside the active EOR well pattern array.

Table 3-32 Difference Between Cumulative Produced Injected Water (CO_2 Prophet model results)

CO_2-EOR Scenario	Volume of Excess Produced Brine (Cumulative Over Lifetime of Single Pattern Flood) (MSTB)
Historical	100.8
State-of-art	246.0
1.5 HCPV CO_2 WAG Injection	240.0

Brine Injection Operations

Statistical analysis of a Texas Railroad Commission dataset of injection wells (heavily biased toward Permian Basin wells) performed by the University of Texas at Austin Bureau of Economic Geology (Hovorka et al., 2003) shows that half of the currently operating Class II injection wells are cased and perforated, the majority of injection systems are closed to the atmosphere, and the majority of wells having a hole size of $7^{7}/_{8}$ inches in diameter and tubing between $2^{3}/_{8}$ and $2^{7}/_{8}$ inches. Their analysis of reported maximum injection pressure gradient (injection pressure/tubing depth) demonstrated that essentially all wells operate below or near hydrostatic gradient. (The maximum surface injection pressure is a function of desired bottomhole pressure and tubing diameter and length, with smaller diameter tubing having greater frictional loss because a greater proportion of the fluid is in contact with tube.)

Water Injection Pump Electricity Requirements

The simple equation to estimate pump brake horsepower requirement shown below (Perez et al., 2009) was applied based on an assumed suction pressure of 14.7 psia, an assumed wellhead discharge pressure of 314.7 psia (300 psig), and a mechanical efficiency of 70 percent. Volume of fluid flowing to the injection well is estimated by results of CO_2 Prophet model runs of historical, best practices, and high CO_2 WAG scenarios.

$$BHP = \frac{Q \times (P_d - P_s)}{1714 \times ME} \tag{5}$$

where

BHP = pump brake horsepower
Q = volume of fluid pumped
P_d = discharge pressure
P_s = suction pressure
ME = mechanical efficiency (typically between 65-75 percent)

Table 3-33 Estimated Total Electricity Demand Over the Life of CO_2-EOR Flood Operations to Pressurize Brine for WAG Injection, Reported for a Single Well Pattern

CO_2-EOR Scenario	Estimated Electricity Demand for Water Injection Over Lifetime of CO_2-EOR Operations for Single Pattern (40-acre, 5-spot)
Historical	3,832
Best Practices	4,756
1.5 HCPV CO_2 WAG Injection	6,463

Emissions associated with production of electricity that is used in brine compression were calculated assuming the national average grid emissions profile described in Appendix B.

Boost Compression of Purchased/Recycled CO_2 for Injection

Initially, CO_2 is assumed to be supplied to the site by a pipeline that transports CO_2 from naturally-occurring CO_2 reservoirs, large anthropogenic CO_2 point sources, or a combination thereof. As CO_2-EOR floods progress and CO_2 breakthrough is observed, CO_2 will increasingly be supplied by that which is separated from produced hydrocarbon gas, recompressed, and recycled to injection wells. Compression is, therefore, assumed to occur centrally at or near the gas processing facility and that pressure used to drive distribution and injection operations.

Boost compression is required to raise the CO_2 feed stream to target injection pressure of 2200 psig (Meyer, no year referenced). CO_2 is supplied to the flood from a combination of two sources: CO_2 that is purchased from a large pipeline, and CO_2 that is recycled from produced fluid stream. The purchased CO_2 is assumed to arrive at the site at a pressure of 1,500 psig (Meyer, no year referenced), and the CO_2 recycled from CO_2-EOR operations leaves the gas processing plant at a pressure of 2,000 psig. The pressure of the CO_2 feed stream is, therefore, calculated as the weighted average pressure as a function of the fraction of CO_2 supplied from each source. These fractions are given in the equations below:

$$fraction\ of\ purchased\ CO_2 = \frac{(vol.\,CO_2\ demand - vol.produced\ CO2)}{total\ volumetric\ CO_2\ demand} \tag{6}$$

$$fraction\ of\ recycled\ CO_2 = \frac{volume\ of\ produced\ CO2}{total\ volumetric\ CO_2\ demand} \tag{7}$$

Based on this calculation method, mean supplied CO_2 pressures for historical, best practices, and high-CO_2 volume injection scenarios were 1690, 1800, and 1850 psi, respectively. Boost compression electricity requirements were, therefore, highest on a per-tonne of CO_2 injected basis in historic cases, but the smaller amount of CO_2 injected in historical cases as compared to other scenarios means that the total compression energy requirements will be lower on a per-flood pattern basis. Boost compression energy requirements were estimated simply as the change in pressure divided by the product of CO_2 density at midpoint between feed and injection pressure times an assumed pump efficiency of 0.75. Table 3-34 summarizes the results of these calculations.

Table 3-34 Summary of Parameters Used in Calculating CO_2 Boost Compression Requirements, and Results of Calculation Reported on a per Pattern-Year Basis

CO_2-EOR Scenario	Historical	Best Practices	1.5 HCPV CO_2 WAG Injection
Fraction of stored to injected CO_2 (%)	51.4	33.7	25.2
CO_2 feed pressure (psig)	1,800	1,853	1,891
Pressure at injection wellhead (psig)	2,200	2,200	2,200
Average flood CO_2 feed rate (tonnes/pattern year)	5,629	9,573	9,972
Estimated average electricity demand to boost compression (MJ/pattern-year)	**51,600**	**74,400**	**67,300**

3.5.5.3 Production Operations

Production operations involve reservoir fluid extraction, either by artificial lifting or by free-flowing well production. Artificial lifting is assumed with a mid-range electricity requirement assumed as noted in Table 3-6. Following production, the produced fluid will be collected for gas/liquid separation (gas expansion chamber), water/oil separation (water knock out), and oil/water emulsion separation (heater treater). In CO_2-EOR fields that produce relatively large volumes of hydrocarbon gases in their produced gas streams, operators may choose to install equipment to separate hydrocarbon gas from CO_2 so that the separated hydrocarbon stream can be sold. In this study it has been assumed that CO_2/hydrocarbon separation will be carried out using the Ryan-Holmes process for distillative separation to remove acid gasses (CO_2 and H_2S) with a propane or butane additive.

Artificial Lift

Under favorable conditions, it may be possible for fluid to be produced, in CO_2-EOR operations, from free-flowing wells. While free-flowing production wells offer obvious cost, energy demand, and maintenance advantages, artificial fluid lifting is, more often, required, with approximately 80 percent of all CO_2-EOR operations employing artificial lift to achieve economic production levels (van Leeuwen et al. 2009). In artificial lifting, pumps are employed to pull reservoir fluid to the surface that would otherwise be too deep and/or viscous to be pushed to the surface by the pressure of the reservoir. Pumps used to achieve artificial lift of fluid in a producing well can be driven by electric (DC or AC) motor or gas engine prime movers, with gas engine drives an attractive alternative when sufficient quantities of gas are generated on site as a result of CO_2-EOR activity. While in practical application the selection of artificial lift pump driver would be based on a detailed analysis of purchase, installation, maintenance, and power costs, it is assumed, for purposes of this study, that AC electric motor prime mover is present on site prior to tertiary recovery operations (remaining from secondary, water-flood recovery operations), and has sufficient capacity for use in tertiary recovery operations. This type of motor has been demonstrated to be resilient in field operation and, while such equipment requires regular repair and maintenance, it can, with proper care, remain in operation indefinitely (Mistry, 2003).

Electricity demand for artificial lift varies as a function of a number of reservoir, fluid, and well parameters, including reservoir depth, reservoir operating pressure, produced fluid viscosity and density (a function of composition and temperature), well tubing diameter and internal roughness. Fluid volumes and properties and formation pressures can also be expected to vary as a function of time as the WAG flood progresses.

Artificial Lift Electricity Demand Estimated Using ARI Reported Value

Results of an informal survey of CO_2-EOR flood operators reveals that electricity-driven lifting power accounts for between 10 and 30 percent of the electricity use by a CO_2-EOR project, and a recent report estimates electricity consumption to be between 0 and 10 kWh per barrel of incremental oil produced, with a mid range of 5 kWh/bbl of incremental oil produced (van Leeuwen et al. 2009). Artificial lift electricity requirements for CO_2-EOR operations were estimated for the three defined scenarios using oil production values for a single well pattern as reported in Section 3.4.1.1, and using the referenced 5 kWh/bbl of incremental oil produced.

Table 3-35 Single Well Pattern Artificial Lift Estimate for CO_2-EOR Scenarios Estimated Using ARI mMid-range Electricity Estimate of 5 kWh/bbl for Historical CO_2-EOR and 10 kWh for Best practices and Next-Generation CO_2-EOR Scenarios

CO_2-EOR Scenario	Single Pattern Total Oil Production (MSTB)	Assumed ARI-Reported Artificial Lift Electricity Demand (kWh/bbl)	Cumulative Single Pattern Electricity Demand (MWh)
Historical	191.5	5 (mid-range)	957.5
Best Practices	301.8	5 (mid-range)	1509
1.5 HCPV CO_2 WAG Injection	361.2	5 (mid-range)	1806

This method of artificial lift electricity production estimation may not adequately account for the decreasing ratio of oil produced to total fluid produced that is expected in high fluid injection scenarios. As a result, a second method was considered for estimation of electricity requirements to drive artificial lifting based on estimation of horsepower demand.

Artificial Lift Electricity Demand Characterization by Prime Mover Horsepower Estimate

Prime mover size for artificial lift can be estimated by applying an empirical equation of the general form shown in the following equation (Manning and Thompson, 1995):

$$HPpm = qxD/PMF \qquad (8)$$

where

q = oil and water daily production (bbls/day)

HP_{PM} = horsepower of prime mover
D = net lift of liquid in feet
PMF = prime mover factor, with
PMF = 135,735 when SG is 1 and lifting with 100 percent efficiency

Generally PMFs are 1.8 to 3 times smaller than 135,735. For high slip NEMA D motors or slow-speed internal combustion engines, recommended prime mover HP can be calculated from: $HP_{PM} = q*D/56000$. For high-speed internal combustion engines or normal slip NEMA C motors, prime mover HP suggested is: $HP_{PM} = 45,000$

For purposes of this study, the depth from which fluid is assumed to be lifted is half of the vertical depth (depth to top of producing formation) (5,826 feet, per Table 3-9), or 2,913 feet. The daily fluid production is estimated as the sum of the oil and water produced. Because the fluid flow rate will vary as the CO_2-EOR flood progresses, the required horsepower to lift fluid will also vary. To address this, the volume of total fluid was estimated for each year in which the CO_2-EOR flood is produced, the horsepower requirement calculated for each one year increment, and lift requirements from all years of pattern operation summed to develop an estimate of total lift requirement over the life of each production well. Results of this calculation are shown in Table 3-36.

Table 3-36 Estimated Electricity Requirement for Artificial Lift for Single Well Pattern as Calculated Based on Estimated Artificial Lift Prime Mover Horsepower Requirement

CO_2-EOR Scenario	Single Well Electricity Demand for Artificial Lift (GWh per well pattern)	Per-Stock Tank Barrel of Crude Produced Electricity Requirement (kWh/ bbl oil)	Per-Surface Barrel of Liquid Produced (kWh / bbl liquid)
Historical	3.83	20.0	1.3
Best practices	4.76	15.8	1.3
1.5 HCPV CO_2 WAG	6.46	17.8	1.3

These results are significantly higher, on a kWh/bbl oil produced basis, than the high electricity demand estimate for artificial lift reported by van Leeuwen (2009). Using values listed in Table 3-36, indirect emissions associated with electricity production that is used in artificial lift activity were calculated assuming national average grid emissions profile described in Appendix A.

Fluid Gathering Lines

Total fluid collected from a producing well is transported to a nearby satellite separation unit where bulk gas is separated from liquid. Bulk gas is transported to an in-field gas processing facility and liquid produced from EOR well pattern is transported via pipeline to the central battery location. It is assumed that relatively high pressure flow lines from the well are made of steel (Langston, 2003), and that production lines from previous water-flood secondary EOR activity in the same field are pre-existing and of adequate integrity and flow volume to accommodate CO_2-flood tertiary EOR fluid flow. In all scenarios considered in this report, it is assumed that the liquid-gathering lines that are used for CO_2-EOR operations are the same as those that were used in secondary recovery operations.

3.5.5.4 Produced Liquids Management: Satellite Separation and Tank Battery Operations

A tank battery is a collection of fluid flow lines, processing equipment, and storage tanks that is designed to process and store liquid that is received from one or more oil producing wells before the oil is transferred to a pipeline or tanker truck for sale. The fluid produced from each EOR pattern varies as a function of reservoir characteristics, fluid characteristics, injection schedule and flow rates. Tank batteries are therefore designed to accommodate the particular conditions and production performance of a specific EOR pattern or set of patterns that make up a lease. The primary factor influencing this design is the amount of fluid that is produced and processed through the system. For purposes of this study it is assumed that fluid produced from 10 well patterns are collected to and processed in a single central tank battery facility. Approximate size, processing capacity, and emissions from elements of a tank batter are estimated based on maximum average fluid production flowrate as estimated using CO_2 Prophet CO_2-EOR scoping model and detailed elsewhere.

Major functions performed in a tank battery are: gas/liquid separation, water/oil emulsion separation, oil storage, water storage, and vapor recovery. Tank battery process elements that perform these functions include:

- **Heater/treater -** Heats water/oil emulsion to separate oil, water, and gas. (atmospheric or pressurized three-phase vessel.)
- **Gun barrel or wash tank -** Separates oil, water, and small amounts of gas. (atmospheric, three-phase vessel)
- **Stock tank -** Stores crude oil that is to be sold (atmospheric pressure)
- **Water storage tank - S**tores produced water prior to disposed or re-injection (atmospheric pressure)

Parameters listed in Table 3-37 have been selected to represent mean conditions observed at each unit process. Temperature and pressure conditions will vary from facility to facility and significant variability can be expected as a function of fluid properties, site conditions, and facility configuration. These values will impact facility performance and environmental emissions, and are used in this LCA to estimate performance of each unit process.

Table 3-37 Process Element Assumptions Made in Characterization of CO_2-EOR Produced Liquids Processing

Unit Process	Number of Units	Flow	Location	Estimated Temperature, °F	Estimated Pressure, psig
High pressure separator	1	Total produced fluid	Satellite Facility	126	300
Low Pressure Separator	1	All but separated gas	Tank Battery	110	100
Heater/Treater	1	Water/oil emulsion	Tank Battery	140	50
Stock tanks (Oil Storage)	2x	Oil	Tank Battery	64	atm
Water Storage Tanks	2x	Produced Water	Tank Battery	64	atm

Estimation of Fluid Separation Performance

Separator facilities can be located at centralized facilities (central batteries), strategically-located decentralized facilities (satellites), or they may be located at both satellite and central separation facilities. A satellite facility can be designed to direct all produced fluid to a central facility or to separate bulk gas before sending liquid water and oil stream on to central battery and bulk gas (CO_2 and hydrocarbon gas) to a gas processing facility. Foregoing satellite separation of bulk gas has the advantage of consolidating operation and maintenance within a relatively small area around the tank battery, but also may create issues with slugging and higher frictional pressure drop over that which would be observed in production systems with gas/liquid satellite production separation. Selection of a separation alternative is best made on a case-by-case basis after site-specific analysis based on such factors as gas-processing facility inlet pressure, crude oil properties, produced gas composition, crude oil sales specifications, water quality specifications, and site layout.

For purposes of this study, it is assumed that fluid produced from five CO_2-EOR well patterns passes through a primary satellite separator where bulk gas is separated from liquid (oil and water). Fluid flow through the separator is driven by fluid pressure and does not require additional electricity for pumping. Liquid is conveyed by pipeline from the satellite separator to the central battery manifold where flow from satellite separators servicing ten tank batteries is collected to a secondary water/oil/gas separator. At this stage nearly all of the free water[6] in the fluid is separated and transported to water storage tank. Oil, water/oil emulsion, and a small fraction of the total free water are transported to a heated vessel to break the water/oil emulsion and complete water/oil separation.

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[6] "Free water" is a term used to describe the fraction of water contained in fluid produced from an oil well that will freely separate from oil, with discrete water droplets separating according to behavior described by Stokes' Law.

Characterization of the construction of two-phase gas/liquid production satellite separators is limited to estimation of the mass of steel of which each separator is composed, emissions associated with production of that mass of steel, and an estimation of the overall number of satellite separation units. Assuming a gas/liquid separator 9 feet in length, 3 feet in outer diameter, and with 0.75-inch vessel thickness, the mass of steel was estimated to be about 1.2 metric tonnes. Based on the guideline that for oil gravity above 35 ° API one minute liquid retention time is recommended, average flow from five patterns can be processed through a gas/liquid separator (also assuming effective volume of half of the total vessel volume).

Water/Oil Emulsion Separation: Heater/Treater Vessel

Following gas, and liquid separation, the oil stream (including free oil, oil/water emulsion, and a small fraction of free water) is moved to a heater/treater vessel in which heat is applied to break the water/oil emulsion and separate water from the product oil. Heating also serves to remove additional gas which is collected for further processing. Natural gas-fired fire tubes provide the heat that is used to achieve this secondary separation. The required number and size of fire tubes is a function of volume of fluid being processed. Required fluid residence time is a function of crude oil API gravity, heater/treater temperature, and desired separation efficiency.

Typical retention time in a vertical or horizontal heater/treater is between 0.5 and 4 hours (Manning and Thompson, 1995), and for loose emulsions with gravity greater than 35 º, emulsion heating for mechanical separation is typically in the range of 100 to 120 °F. The water-oil emulsion for oil with gravity of 36 º API is estimated to contain entrained water at approximately 11 percent by volume (Manning and Thompson, 1995). In addition to entrained water, a small fraction of free water is drawn into the heater/treater vessel (free water knock out separation efficiency is assumed to be 98 percent of free water). It is assumed that a single heater/treater vessel is required to service a single tank battery.

EPA AP-42 Method to Estimate Heater/Treater Fugitive Emissions

AP-42 specifies methane emissions from heater-treater to be 19 scf of CH_4 per day per heater, and 0.319 scf CO_2 per day per heater. This corresponds to production rates of 6935 scf of CH_4 per year for a single heater treater, and 116 scf of CO_2 per year. It is assumed that the gas generated in the heater treater is collected by a vapor recovery unit (VRU), sent to a TEG unit for dehydration, and then sold or recombined with new CO_2 and reinjected (this option is not considered in this report).

These emissions estimates offer only a coarse estimate of CO_2 and methane emissions, and do not take into account vessel flow rate, temperature/pressure conditions, or emulsion characteristics. They are therefore considered to be insufficiently rigorous to serve the purposes of this study and are offered only for comparison with results arrived at using the U.S. EPA TANKS model. Even then, real process, stream composition, and flow rate data would significantly improve the estimates beyond what is estimated using the TANKS methodology.

Estimation of Heater/Treater Firetube Heat Duty and Boiler Emissions

Estimation of crude treating temperatures and rates based on tables provided by Manning and Thompson (1995) suggest a required emulsion heating temperature and treating rate (assuming mechanical emulsion separation) of 140 °F and 57 bpd/ft^2. Based on this treatment rate, calculated heat duty for a heater treater firetube burner is on the order of 1 MMBtu/hour. In all CO_2-EOR scenarios, heater/treater firetube heat duty is below the threshold set by the EPA for application of uncontrolled, small boiler emissions factors (<100 MMBTU/hour heat input), and these emissions factors have been applied to all heater/treater natural gas combustion equipment.

Emissions of heater/treater firetube boiler were estimated based on U.S. EPA AP-42 emissions factors for common criteria air pollutants, greenhouse gasses, organic compounds, and metals, taken from the *U.S. EPA AP 42 section 1.4: Natural Gas Combustion, Emission Factors* for an uncontrolled boiler. The amount of natural gas combusted to heat fluids in the heater/treater was estimated using the heat duty equation my Manning and Thompson (1995) presented below:

$$Heat\ Duty\ (btu/day) = (Q_{oil} * Cp_{oil} + Q_{water} * Cp_{water}) * \Delta T * (1 + heat\ loss) \qquad (9)$$

where

Heat duty = heat duty of heater/treater in btu of natural gas per day
Q_{oil} = daily flow of oil to heater/treater, barrel of oil per day
Q_{water}=daily flow of water to heater/treater, barrel of oil per day
ΔT = change in temperature between influent stream and vessel, °F
Cp_{oil} = Saybolt viscosity of oil, Saybolt second units (SSU)
Cp_{water} = Saybolt viscosity of water, SSU
Heat loss = percent vessel heat loss (for a well-insulated vessel, assumed to be 2 percent)

To estimate total emissions over the life of CO_2-EOR operations from natural gas combustion to heat water/oil emulsion at a single tank battery (for each operational scenario), an average annual heat duty was calculated for each year of operation for each CO_2-EOR operational scenario using assumptions listed in Table 3-38.

Table 3-38 Assumptions Used in Estimation of Heater/Treater Firetube Heat Duty. In addition to these parameters, the flow of oil to the heater/treater was estimated for each year of CO_2-EOR activity based on the aggregated flow from 10 producing wells feeding a single tank battery

Parameter	Value	Units
Oil/water emulsion treatment temperature	140	°F
Temperature of influent stream	110	°F
Δ Temperature across heater/treater	30	°F
Saybolt viscosity of oil	150	SSU
Saybolt viscosity of water	350	SSU
Heat loss of well-insulated vessel	0.02	fraction

Annual heat duty requirement was summed for all years of tank battery operation (all years of CO_2-EOR flood operation) to determine the total heat duty (calculated for each CO_2-EOR operational scenario). Based on the calculated heat duty over the life of the tank battery, natural gas combustion emissions were estimated for the full life of CO_2-EOR operation from 10 CO_2-EOR flood patterns (one tank battery). These data are summarized in Table 3-39, and corresponding combustion emissions data are shown in Table 3-40.

Table 3-39 Estimated Energy Requirement of Firetube Used To Heat Heater/Treater Servicing 10 CO_2-EOR Well Patterns

Parameter	Historical	Best Practices	1.5 HCPV CO_2 WAG Injection	Units
MMBtu required over life of CO_2-EOR operations for heater/treater firetube (tank battery supplies 10 CO_2-EOR well patterns)	46,200	63,000	81,300	MMBtu
MMscf natural gas equivalent (1020 btu/scf natural gas)	45.3	61.7	79.7	MMscf natural gas at 1020 btu/scf

Table 3-40 Estimated Combustion Emissions from Heater/Treater Firetube Operation for a Unit Servicing 10 Well Patterns Over the Life of the CO_2-EOR Flood

Constituent	Historical	Best Practices	1.5 HCPV CO_2 WAG Injection	Units
GHGs				
CO_2	14,500	13,500	12,100	kg/(pattern*year)
Methane	0.28	0.26	0.23	kg/(pattern*year)
N_2O	0.27	0.25	0.22	kg/(pattern*year)
Criteria Air Pollutants				
NO_X	12.1	11.1	10.1	kg/(pattern*year)
CO	10.2	9.42	8.45	kg/(pattern*year)
PM (Total)	0.92	0.85	0.76	kg/(pattern*year)
SO_2	0.07	0.07	0.06	kg/(pattern*year)
VOC	0.67	0.62	0.55	kg/(pattern*year)

In addition to combustion emissions from the heater/treater, the vessel also has emissions associated with working, breathing, and flashing losses. As discussed elsewhere, these emissions are assumed to be controlled largely through installation and operation of a vapor recovery unit at the stock tank battery. Uncontrolled tank working and breathing losses were calculated using the U.S. EPA Tanks models with the tank assumptions specified in Table 3-41. Estimation of uncontrolled flashing emissions was estimated using the Vazquez-Beggs equation. Results of estimated uncontrolled and controlled working, breathing, and flashing losses from the heater/treater are summarized in Table 3-41.

Table 3-41 Design Assumptions Used in Estimating Heater/Treater Vessel Working, Breathing, and Flashing Emissions

Parameter	Value	Units
Vessel diameter	6	ft
Vessel height	12	ft
Maximum heat duty	500	Mbtu/hr
Target liquid residence time range	1-4	hours
Total volume of heater/treater vessel	60	ft^3
Fraction of total volume as working volume	0.66	ft
Effective working volume of heater/treater	40	ft^3

Table 3-42 Estimate of Working, Breathing, and Flashing Emissions from Heater/Treater Vessel That Are Collected to the Vapor Recovery Unit

CO_2-EOR Scenario	Tank Contents	Flash Losses (kg/tank-year)	Working Losses (kg/tank-year)	Breathing Losses (kg/tank-year)	Total Losses per Tank per Year (kg/tank-year)
Historical	Water Oil Emulsion	125,900	3062	58.4	129,000
Best Practices	Water Oil Emulsion	132,300	3059	58.4	135,400
1.5 HCPV CO_2 WAG Injection	Water Oil Emulsion	122,700	3064	58.4	125,800

3.6 Crude Oil Storage

Oil storage tanks are designed to hold oil that has been collected from producing wells and separated from water, CO_2, and hydrocarbon gas within the tank battery prior to transfer from lease operations to the pipeline or tanker truck. Storage provided by these tanks also provides a buffer to stabilize flow between production operations and sales. For purposes of this study, it has been assumed that all oil storage tanks meet American Petroleum Institute API-650 Specification, and that there is redundancy in both oil and water storage tanks.
Size of tanks required to store produced oil from 10 wells was estimated based on the maximum flow of oil generated from 10 producing wells, as described in the above section on estimation of reservoir production, the number of tanks in use, and the specified range of tank annual turnovers (tank volumetric throughput per year divided by tank working volume). Assuming that two crude oil storage tanks are located at each tank battery, tanks with a diameter of 12 feet, and a shell height of 15 feet with capacity of 12,600 gallons (300 barrels) are specified. It is assumed that a single crude storage tank is used unless the number of tank turnovers per year exceeds 1000 (Oklahoma DEQ, 2006). In cases where turnover for a single crude storage tank exceeds this threshold, a second crude storage tank is assumed to be brought online to cut in half the number of turnovers per year during those years of peak tertiary oil production. Assuming a mean working crude oil height of 12 feet (corresponding to 80 percent total volume), the average number of turnovers is between 450 and 550 for all CO_2-EOR scenarios, a range that is well within that which is considered to be appropriate for tank battery crude storage tanks—100 – 1,000 per year (Oklahoma DEQ, 2006).

3.6.1 Estimation of Crude Oil Storage Tank Losses

Flashing losses result from sudden decreases in gas solubility when fluid is transferred from higher to lower pressure and/or lower to higher temperature conditions. Standing losses (also called storage or breathing losses) occur when the liquid in the tank expands and contracts due to changes in ambient temperature or barometric pressure. Working losses describe the fraction of total losses that occur as result of headspace gas displacement resulting from changes in storage tank volume (those that occur as a tank is emptied or filled). Oil storage tank standing and working losses were estimated using EPA TANKS model version 4.0.9d; flashing losses were estimated using the Vasquez - Beggs Solution Gas/Oil Ratio (GOR) correlation method using the mean Permian basin GOR as reported in Table 3-9.

The EPA Tanks model calculates estimated storage tank losses based on tank dimensions, throughput of stored fluid per unit time, fluid speciation and vapor pressure characteristics, and environmental conditions to which the vessel is exposed (determined as a function of site location). Crude oil storage tank specifications used in development of standing and working loss estimates are summarized in Table 3-43. It has been assumed that the vessel contains crude oil with a Reid vapor pressure (RVP) of 5 psi. RVP is a commonly used measure of the volatility of petroleum and petroleum products, and is defined as the absolute vapor pressure exerted by a liquid at 100 °F (37.8 °C) as determined by the test method ASTM-D-323—a value differing slightly from a liquid’s true vapor pressure.

Table 3-43 Specifications Used in Calculation of Well Tank Emissions

Parameter	Value	Units
City, State	Midland-Odessa, Texas	-
Type of Tank:	Vertical Fixed Roof Tank	-
Shell Height (ft):	15	Feet
Diameter (ft):	12	Feet
Max Liquid Height (ft) :	15	Feet
Avg. Liquid Height (ft):	12	Feet
Total Volume (gallons):	12,690	Gallons
Paint Characteristics		
Shell Color/Shade:	Whte/White	-
Shell Condition:	Good	-
Roof Color/Shade:	Grey/Light	-
Roof Condition:	Good	-
Roof Characteristics		
Type:	Dome	-
Height (ft)	2.00	Feet
Radius (ft) (Dome Roof)	12	Feet
Breather Vent Settings		
Vacuum Settings (psig):	-0.03	psig
Pressure Settings (psig)	0.03	psig

Meteorological Data used in Emissions Calculations: Midland-Odessa, Texas (Avg Atmospheric Pressure = 13.28 psia)

The average crude oil annual throughput for a single tank was estimated for each CO_2-EOR scenario, and that flow rate was applied to a tank of the design specification to estimate the average total annual losses (sum of annual flashing, breathing, and working losses) per tank. This estimate of scenario-specific total annual per-tank loss was multiplied by the total number of operational tank-years (number of tanks in operation per year times the number of years each tank is in operation) over the life of the CO_2-EOR flood (a value that varies for each CO_2-EOR scenario). One shortcoming of this methodology is that the EPA TANKS model cannot estimate the specific composition of the released vapor unless the specific composition of the liquid stored in the vessel is known. In the absence of specific tank vent gas composition data, sampled data were used from a 2000 Btu/scf vapor gas sample reported by Southern Research Institute (2002), and summarized in Table 3-48. Results of these calculations are shown in Table 3-44.

Table 3-44 Mass of Hydrocarbon Gas Released from Crude Storage Tank Over Lifetime of 10 Pattern Tank Battery Operations (an estimated 95% of this vapor is collected by a VRU)

CO_2-EOR Scenario	Total Tank Releases Throughout CO_2-EOR Operation, lb VOC
Historical	1,404,000
Best Practices	2,187,000
1.5 HCPV CO_2 WAG Injection	2,689,000

Table 3-45 Summary of Crude Oil Tank Emissions Estimate (working and breathing losses estimated using EPA Tanks model, flashing losses estimated using the Vasquez-Beggs equation)

CO_2-EOR Scenario	Tank Contents	Tank-Years in 10-well Tank Battery Full EOR Performance	Average Number of Turnovers per Year per Tank	Average Throughput per Tank per Year (stb/tank year)	Estimated Tank Emissions (kg/tank-year)			
					Flash Losses	Working Losses	Breathing Losses	Total Losses per Tank per Year
Historical	Crude oil, RVP-5	22	467	173,100	26,900	1,890	171	29,000
Best Practices	Crude oil, RVP-5	30	496	199,500	30,000	1,830	171	32,000
1.5 HCPV CO_2 WAG Injection	Crude oil, RVP-5	41	521	179,300	28,600	1,860	171	30,600

It should be noted that, in addition to the two tanks considered to be in active use for crude oil storage, there are expected to be one or more additional crude oil storage tanks that provide an engineering safety measure that would prevent shut-in of production or stoppage of operations in the event of post-production interruption. However, any redundant storage tanks would not be in regular use and emissions associated with fluid storage in those vessels have not been considered.

3.7 Produced Water Tank CH_4 Emissions Estimate

After water produced to the surface from CO_2-EOR flood operations is separated from produced oil with which it is comingled, it is stored within the tank battery in a brine storage tank or tanks. The produced brine contains dissolved and entrained methane that is released as the brine is depressurized through post-production operations. Methane contained in produced water is of a significantly smaller concentration than that entrained in an equivalent volume of produced oil, since CH_4 has a stronger affinity for hydrocarbon than for water. However, the methods used to estimate flashing emissions losses from oil are based on properties specific to the produced oil and cannot, therefore, be modified to describe similar losses from produced water. In the absence of measured data, emissions factors can be estimated from produced saline water that is delivered to storage tanks. As reported in Table 3-9, the model brine saline content for produced water is 96,000 parts per million (ppm) by volume, or approximately 10 percent. The separator vessel immediately upstream of the water tank was reported earlier to be 100 psig. Based on this, the most appropriate value listed in the API GHG emissions methodology manuscript is between the value reported for upstream separator pressure of 250 psig and produced water salt content of 10 percent (0.0150 tonnes CH_4 per 1000 bbl produced water) and the value reported for upstream separator pressure of 50 psig and produced water salt content of 20 percent (0.0015 tonnes CH_4/1000 bbl produced water). In the absence of a better estimation method, it is assumed that the lower of the two reported values is an appropriate estimate of CH_4 emissions from the water storage tank. It is assumed that 95 percent (by volume) of the generated methane emissions are collected by the vapor recovery unit, and that only 5 percent are released to the atmosphere.

Table 3-46 Methane Produced from Brine Storage Tanks and Collected by VRU or Released to Atmosphere—Reported on per Pattern-Year Basis (40-acre, 5-spot well pattern)

Parameter	Historical	Best Practices	1.5 HCPV CO_2 WAG Injection	Units
Volume methane from brine tanks	12,900	10,600	10,000	scf CH_4/pattern-yr
Mass of recovered methane	232	190	180	kg per pattern-yr
MJ HHV of recovered methane	12,900	10,500	10,000	MJ/pattern-yr
Methane emitted to atmosphere	12.2	10.0	9.5	kg per pattern-yr

3.7.1 **Venting/Flaring and Vapor Recovery**

According to the Natural Gas STAR Partners, a voluntary partnership between the U.S. Environmental Protection Agency and the oil and gas industry, 26.6 billion cubic feet of gas is lost each year in the U.S. from the approximately 573,000 crude oil storage tanks that are in use. Constituents including methane, non-methane VOCs, natural gas liquids (NGLs), other hazardous air pollutants, and inert gasses that are dissolved or physically entrained in produced crude oil evolve or "flash out" of the crude as pressures and temperatures to which the crude oil is exposed change. These vapors collect in the space between the liquid level and the fixed tank roof, and are often vented to the atmosphere as the tank liquid level fluctuates (commonly referred to as "breathing losses") (U.S. EPA, 2006). One means of avoiding these losses and generating a valuable product stream is installation of vapor recovery units (VRUs) that capture vapors evolved from oil storage tanks.

VRUs are relatively simple systems that capture approximately 95 percent of the Btu-rich vapors that are released from crude oil stored in stock tanks. There are between 8,000 and 10,000 VRU units installed in the U.S. and, on average, each unit recovers vapors from four tanks (U.S. EPA, 2006). A VRU system comprises manifolds connecting one or more tanks to a common suction line and piped to the VRU suction scrubber, an independent sensing line from the most active or farthest tank to the sensing unit on the VRU, discharge piping from the VRU to the gas gathering line, a meter run, or the suction of the field gas compressor (U.S. EPA, 2006). Condensates that precipitate in the suction scrubber are typically returned to the stock tanks. The VRU operation is automated as a function of the headspace pressure observed in the tank, and includes systems to bypass flow and/or automatically shut down compression to avoid issues such as fugitive emission, introduction of oxygen, and implosion of tanks. Compression in the VRU is achieved using either rotary screw or rotary vane compressors, since they are best suited to handle wet gas. It is assumed that VRU is driven by variable speed electric compressors that can be adjusted to meet the vapor production rates that will vary as a function of production rates that change with flood maturity, and environmental conditions that vary on a daily and seasonal basis.

3.7.1.1 **Characterization of Vapor Recovery Unit Performance**

It is assumed that operators will use the transition from secondary to tertiary EOR flood operations as an opportunity to install VRU technology, both as a means of voluntarily reducing tank battery emissions, and to generate a valuable, Btu-rich gas product for sale or use onsite (Natural Gas STAR partners report VRU system payback periods of as little as six months). As such, it is assumed that venting practices will be eliminated, and flaring will only be used in instances of system upset/failure. Because catastrophic events are not considered within the scope of this analysis, both flaring emissions will be neglected. The choice to consider VRU as new infrastructure is considered to be conservative, since most oil production systems currently in operation are already equipped with VRUs (Melzer, 2010).

In general, the volume of vapor captured is a function of the volume of oil passing through the tanks, the composition of the crude oil, the pressure at which separators discharge to the tank, the tank configuration, and seasonal daily temperatures. VRU performance has been characterized based on tank throughputs as estimated using volumetric flows to a single tank battery from ten producing wells. Working and breathing losses were estimated for oil storage tanks and heater/treater vessels using the U.S EPA TANKS version 4.0.9d, as described above. Flashing losses resulting from sudden decreases in gas solubility when fluid is transferred from higher to lower pressure and/or lower to higher temperature conditions are estimated using the Vazquez-Beggs equation, as described previously. For all vessels from which vapors are recovered, a recovery efficiency of 95 percent by volume has been assumed. Based on this recovery efficiency, a total volume of gas collected by the VRU is estimated to be 524, 328, and 346 Mscf per pattern year of 2000 btu/scf vapor for historical, best practices, and high CO_2-EOR operational scenarios, respectively. Table 3-47 summarizes vapor recovery and methane/non-methane VOC emissions. Table 3-44 summarizes composition and constituent properties for the 2000 btu/scf HHV; this composition is assumed for all tank battery vapor calculations. Following recovery, vapor is transported to a solid desiccant dehydration unit prior to sale, or for on-site use, (Sidebottom and Richards, 2009) or recycling (Melzer, 2010).

Table 3-47 Summary of Vapor Recovery Unit Performance for Each Operational Scenario Considered, Reported on a per Pattern-Year Basis (40-acre, 5-spot patterns in all cases)

Parameter	Historical	Best Practices	1.5 HCPV CO_2 WAG Injection	Units
Volume vapor recovered	486	538	492	Mscf 2000 btu/cft gas per (pattern-yr)
VRU electricity use	15,200	14,100	13,400	MJ electricity used per pattern-yr
HHV of recovered vapor	1,025,000	1,134,000	1,038,000	MJ recovered vapor per pattern-yr
Mass vapor released	3,483	3,854	3,528	lb vapor released per pattern-yr
Mass CH_4 released to atm.	954	1,056	967	kg CH4/(pattern-yr)
Mass NMVOC released to atm.	2,529	2,798	2,562	kg NM-VOC/(pattern-yr)

Table 3-48 Summary of Tank Battery Vapor Composition for 2000 Btu/scf HHV Gas Collected by Vapor Recovery Unit

Constituent	Mol %	Volume %	Weight %	MW (g/mole)	HHV (MJ/kg)	Density (lb/ft^3)
N_2	4.7	4.7	3.7	28.01	0	0.0727
O_2	0.7	0.7	0.6	32.00	0	0.0831
CO_2	0.2	0.2	0.2	44.01	0	0.1142
CH_4	46.3	46.5	21.0	16.04	55.5	0.0416
Ethane	10.1	10.1	8.6	30.07	51.9	0.0780
Propane	12.0	12.0	15.0	44.1	50.35	0.1144
Isobutane	5.7	5.7	9.4	44.1	49.5	0.1509
n-butane	6.2	6.2	10.2	58.12	49.5	0.1509
Isopentane	3.5	3.5	7.1	72.15	49.01	0.1870
n-Pentane	2.5	2.5	5.1	72.15	49.01	0.1870
Hexanes plus	7.9	7.9	19.1	86.17	48.77	0.2236
Tank Battery Vapor	99.7	100.0	100.0	35.47	49.64	0.0937
Tank Battery NM-VOC fraction	47.8	48	74	53.36	49.68	0.1389

Calculated from reported as-received vent gas sample (Southern Research Institute, 2002)

3.8 Desiccant Dehydrators

Desiccant dehydration is an alternative to glycol dehydration systems that is appropriate for applications in smaller throughput conditions. Based on the design assumptions made for characterization of tank battery operations (accepting liquids from 10 specified CO_2-EOR patterns), the calculated required triethylene glycol circulation rate was sufficiently low to justify replacement of a liquid desiccant system with a solid desiccant dehydration unit. Solid desiccant dehydrators remove moisture from process gasses by passing moist gas through a packed bed of solid desiccant beads or pellets (typically composed of salts such as calcium, potassium, or lithium chlorides) (API, 2009). Because solid desiccant systems are fully enclosed, they have significantly lower overall emissions, only releasing CO_2 and CH_4 when the system is opened to replace spent desiccant. API greenhouse gas emissions methodology document cites a 2003 EPA Gas STAR Lessons Learned document equation for estimating annual emissions from this intermittent source:

$$GLD = \frac{H \times D^2 \times \pi \times P_2 \times G \times N}{4 \times P_1} \qquad (10)$$

where

GLD = gas loss from desiccant dehydrator, scf/year
H = dehydrator vessel height, ft
D = dehydrator vessel inside diameter, feet
P_2 = gas pressure, psia
P_1 = atmospheric pressure, psia
G = fraction of packed vessel volume that is gas, and
N = number of desiccant change outs per year.

Table 3-49 Parameter Values Used in eEstimation of Venting Emissions from Solid Desiccant Dehydration System

Parameter	Value (units)
Height	6.4 (feet)
Internal diameter	1.6 (feet)
Pressure of gas inside the vessel	450 (psig) – 4513.28 (psia)
Atmospheric pressure	13.28 (psia)
Desiccant bed replacement rate	52 (replacements/year)
Volumetric packing efficiency, %	45
Vessel gas CH_4 content, vol.%	46.5
Vessel gas NMVOC, vol.%	48

Based on this set of assumptions, the total estimated volume of gas produced per tank battery solid desiccant system per year is estimated to be 10.5 Mscf/year. Assuming the gas densities listed in Table 3-44 for methane and non-methane VOC fractions, and noting that desiccant systems process vapor from liquid produced from 10 well patterns, emissions values of 9.2 kg CH_4/pattern-year, and 31.8 kg NMVOC/pattern-year were calculated for all operational scenarios.

3.9 Gas Processing Facility Operation

Gas that is produced from CO_2-EOR operations contains both CO_2 and hydrocarbon (HC) gas. The fraction of HC gas contained in the total bulk gas that is separated from liquids (oil and water) at production satellite facility varies as the flood progresses, but is generally high in initial phases of CO_2-EOR production and tapers off as CO_2 breakthrough increases and total hydrocarbon production decreases. The handbook of the CO_2 Predictive Model (Ray and Muñoz, 1986) specifies a threshold gas production rate of 5.0 MMCF/day, below which CO_2-EOR operations gas processing is assumed to include only dehydration and recompression of whole gas. However, modern floods have examples in which the volumes of recycle gas are dramatically higher and no NGLs are removed. Nonetheless, CO_2-EOR operations with daily flows greater than this threshold were assumed to process produced gas by full hydrocarbon gas separation and recycle of concentrated CO_2 for reinjection. An early summary report on CO_2-EOR prepared by the National Petroleum Council (Bailey and Curtis, 1984) identifies a peak total gas production rate threshold of approximately 20 MMscf/day above which CO_2-EOR operations for a single reservoir justify installation of a dedicated gas processing plant (Figure 3-19). Based on these reported values, it has been assumed that a gas-processing plant will include full CO_2 stream separation and recycle, and that CO_2-EOR operations will require construction of a dedicated gas- processing facility with separation of CO_2, recycle of concentrated CO_2, dehydration and sale or combustion of gas, and recovery of NGL.

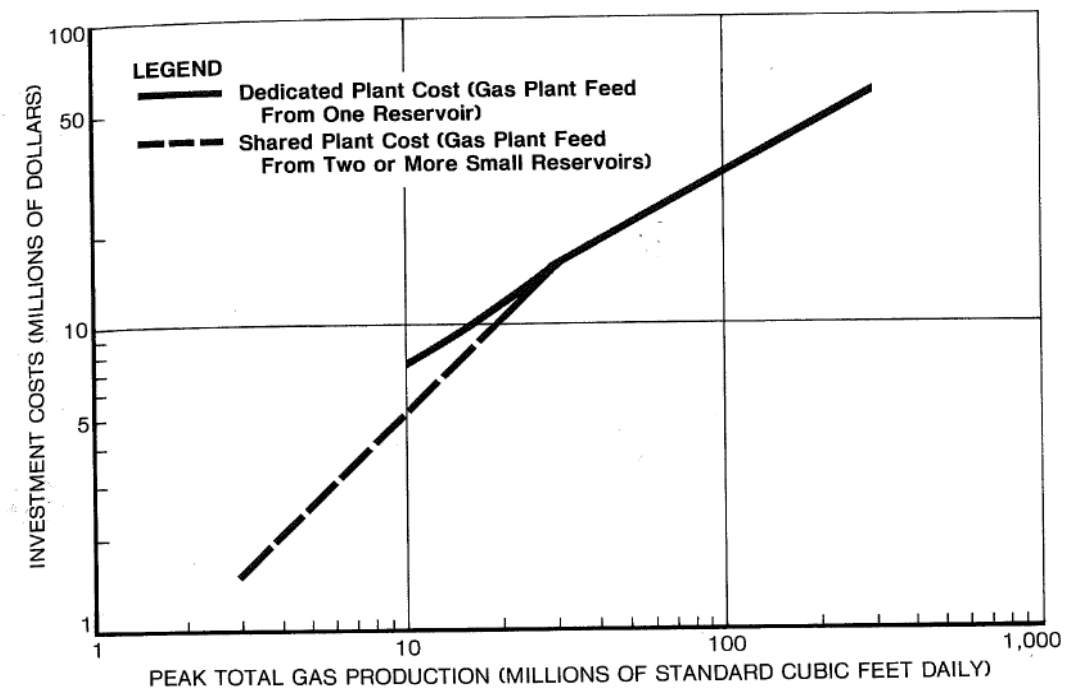

Figure 3-19 CO_2-PM Model Established a Peak Total Gas Production Threshold of 20 MMscf/day Above Which a CO_2-EOR Operation Was Assumed to Require Construction of a Dedicated Gas Processing Facility

Figure source: Bailey and Curtis (1984)

3.9.1 **Characterization of Ryan-Holmes CO_2 Separation and NGL Recovery**

The Ryan-Holmes process is a distillation separation process that separates natural gas liquids (NGLs) from a CO_2 stream by taking advantage of the difference in dew point between CO_2 and different hydrocarbon fractions—selectively separating fractions as they condense at distinct points in a vertical fractionation column or series of columns. The primary energy demand for a Ryan-Holmes process results from the compression of refrigerant that is used to cool the separation column. In CO_2-EOR operations, the primary function served by the Ryan-Holmes process is considered to be the separation of CO_2 from mixed gas stream, while generation of NGL product represents a secondary function; the primary product is CO_2 that is recycled to CO_2-EOR injection and the NGL is a secondary co-product. Depending on the number of separation columns used and the tolerance of process control, operations can be tuned to separate other products including ethane and sulfur from the fluid stream.

3.9.1.1 Description of Model Facility Used in Characterization

Gas processing facility emissions and resource requirements were characterized based on a CO_2-EOR carbon dioxide separation and natural gas processing plant operating permit renewal application submitted by Whiting Oil and Gas Corporation Operating Dry Trail Gas Plant, Texas County, Oklahoma (Milligan, 2007). The facility is designed to accept 45 MMscfd low sulfur gas produced from CO_2-EOR flood operations, and processes that gas by dehydrating, compressing, and separating various fractions through the patented Ryan-Holmes separation process (Process Systems International). Recovered CO_2 is recycled to CO_2-EOR operations where it is re-injected into the target reservoir to stimulate additional oil production. Separated hydrocarbon gas is largely used on site to fuel gas processing plant operations, with the remainder delivered to pipeline for off-site sales. Natural gas liquids (NGLs) are collected to a storage tank and transported periodically offsite by truck for sales.

Bulk gas produced from CO_2-EOR operations enters the facility through a metering facility, undergoes primary gas filtration/separation to remove any entrained solids or free liquids, and then enters a dehydration unit where wet gas is contacted with the liquid desiccant tri-ethylene glycol (TEG). Moisture-lean TEG absorbs water from the CO_2-EOR product gas stream before being cycled to a second vessel where moisture-rich TEG is thermally regenerated using heat supplied by a hot oil heater. Emissions from the still vent and flash tank of the TEG unit are collected by a VRU and returned to the facility inlet; TEG unit emissions are therefore considered to be negligible. Dehydrated CO_2-EOR product gas is then compressed; compressor discharge is cooled; and cooled, compressed gas is moved to the propane recovery column (PRC) of the Ryan-Holmes CO_2 purification unit.

The Ryan-Holmes process involves three vessels; the PRC, a de-methanizer, and a gas/gas exchanger. Dehydrated, compressed, and cooled inlet gas is introduced at the middle of the trayed PRC column and is partially condensed by the propane refrigerant. The lighter “overhead” fraction is moved to a PRC reflux accumulator wherein liquids and vapor are separated. CO_2-rich vapor is compressed and combined with liquid CO_2 product, while light hydrocarbon-rich vapor is sent to the de-methanizer. Liquid from the PRC reflux accumulator is either sent to CO_2 recycle pipeline pumps, or returned to reflux the PRC. The PRC column bottoms are composed of heavier components (mostly C_{5+}) that are transported to the gas/gas exchanger for use as an additive to facilitate hydrocarbon separation. Natural gas liquids drawn from the middle of the PRC column are cooled to 120 °F, combined with excess C_{5+} additive, and sent to the NGL storage tank. Natural gas used to power the plant is drawn from the de-methanizer overhead

The Ryan/Holmes Process uses a propane refrigeration system that is capable of cooling the process stream to low temperature levels required for distillative separation. Propane vapor is compressed by primary refrigerant compressors, then combined with propane refrigerant vapors from the refrigerant economizer overhead moved to a second stage of compression, before being condensed in a refrigerant condenser and stored in a refrigerant surge tank. Liquid propane is sent to cool the process stream in the PRC condenser and the gas/gas exchanger columns, and propane vapors are returned to the refrigerant compressor array.

A closed-loop oil system is used to heat and regenerate moisture-rich TEG in the gas dehydration unit. The oil stream moves through a series of heat exchangers where process waste heat is recovered to preheat the oil before final heating to 450 °F by a natural gas-fired hot oil heater. Hot oil is moved to the dehydration plant to thermally regenerate the moisture-rich liquid desiccant stream.

The gas processing facility uses five compressors driven by natural gas-fired Superior 2416G engines and one electric compressor. Two of the six compressors compress inlet gas and four compress propane used as refrigerant in the Ryan-Holmes process. Two natural gas-fired Solar Saturn T-1,300 turbine generator sets produce electrical power for on-site use. Finally, a Katolite 8163-7405 diesel-fueled generator set is maintained for standby power generation and, as such, is not in regular use. Table 3-52 summarizes major process components and related fuel use.

3.9.1.2 Ryan-Holmes Process Stream Flow Calculations

Estimations of energy feedstock demand, NG and NGL production are based on the assumptions that the volume of gas mixture entering the combined Ryan-Holmes separation/compression process is approximately the sum of produced CO_2 and produced hydrocarbon gas from CO_2-EOR operations, and that the density of this gas mixture is comparable to that observed in the Ryan-Holmes process as reported by Simpson (2008)—0.117 lbm/ft^3.

Based on CO_2-EOR flood screening model results summarized in Section 3.4.2, the volumes of CO_2 and hydrocarbon gas generated (MMscf) over the life of flood operation were predicted for a single well pattern. From these data, the average total gas production per year of pattern operation were calculated for each operational scenario. As mentioned previously, the Whiting Dry Trail Gas Plant has a reported plant throughput capacity of 45 MMscf per day (Milligan, 2007). The average rate of total gas production (CO_2 + hydrocarbon gas) and the estimated number of well patterns that can be accommodated by a gas processing plant of this size are reported in Table 3-50.

Table 3-50 Summary of CO_2-EOR Bulk Produced Gas (CO_2 + hydrocarbon gas) Supplied to Gas Processing Facility

CO_2-EOR Scenario	Average Daily Gas Production (CO_2 + HC gas) per Well Pattern Day, MMscf/Pattern-Day	Average Annual Gas Production (CO_2 + HC gas) per Well Pattern per Year, MMscf/Pattern-Year	Number of Well Patterns Served by Single 45 MMscf/day Gas Processing Plant
Historical	0.200	73	225
Best Practices	0.376	137.4	120
1.5 HCPV CO_2 WAG Injection	0.426	157.7	106

3.9.1.3 Estimation of Produced Hydrocarbon Gas Composition

Results of CO_2 Prophet model runs provide estimates of the volume hydrocarbon gas generated as a result of CO_2-EOR operations, but do not provide details on properties of the mixed hydrocarbon gas. To estimate an appropriate gas composition, molecular weight, and heating value of the produced gas, the Nehring Database was filtered to identify wells located in the Permian Basin that produce oil with API gravity values similar to that of the model reservoir. Adjusted average gas composition values were estimated in this manner: Nehring well database (2007) was filtered to identify a subset of reservoirs located in the Permian Basin, producing oil with corresponding API gravity between 32.5 ° and 37.5 °, and for which gas composition values are provided for methane, ethane, propane, butanes, pentanes, hexanes, carbon dioxide, hydrogen sulfide, nitrogen, and helium. Mean values were calculated for these 53 samples. Because average values were taken for each parameter, the sum was slightly less than 100 percent gas composition (98.5 percent). To account for this, the mean value and standard deviation for each constituent were multiplied by (100 percent /98.5 percent) to adjust to 100 percent total volume. Calculated adjusted average gas composition from wells meeting these criteria are reported in Table 3-51.

Table 3-51 Adjusted Average Composition of Hydrocarbon Gas Produced from the Permian Basin with API Gravity Between 32.5 ° and 37.5 °

Hydrocarbon Gas Constituent	Formula	Mean Composition (wt %)[a]	Standard Deviation
Methane	CH_4	72.34	18.73
Ethane	C_2H_6	12.21	10.33
Propane	C_3H_8	4.02	4.05
Butanes	C_4H_{10}	1.27	1.48
Pentanes	C_5H_{12}	0.50	0.62
Hexanes Plus	C_6H_{14}	0.24	0.45
Carbon Dioxide	CO_2	1.75	6.55
Hydrogen Sulfide	H_2S	0.62	3.14
Nitrogen	N_2	7.01	13.25
Helium	He	0.03	0.07

[a] *Database does not specify composition as percent by weight or volume. Weight percent is assumed. Sample size of 53.*

The mean higher heating value from these 53 samples was 1141.6 btu/ft^3, with a standard deviation of 217.0 btu/ft^3 (Database does not specify lower or higher heating value—reported values are assumed to be higher heating values.). This estimated gas composition corresponds to molecular weight average of 21.3 and a calculated gas specific gravity of 0.70 (air specific gravity is 1.0). The gas composition estimate arrived at in this manner is assumed to be representative of the hydrocarbon gas composition generated by CO_2-EOR activity in the model reservoir. As is shown in reservoir production estimates, the fraction of whole produced gas that is hydrocarbon gas of this composition will change over time as CO_2 breakthrough increases and hydrocarbon production trails off. The gas composition specified above and the degree of dilution with CO_2 as specified by CO_2 Prophet model results are used to estimate gas processing facility influent composition and heating value.

3.9.1.4 Gas Processing Facility Emissions Estimate

Emissions from the gas processing facility were developed by Milligan (2007) based on previously detailed combustion equipment specifications, manufacturer emissions data, EPA AP-42 emissions factors for fugitive emissions, and estimated process stream properties. Engine emissions were estimated based on continuous operation (8,760 hours/year). Formaldehyde emission estimates were assumed to be reduced by 75 percent of untreated emissions in cases where post-combustion oxidation catalysts are used. Emission estimates for the 13.48 MMBtu/hour hot oil heater were based on manufacturer's data, which report emissions factors of 0.08 lb NO_X /MMBTU, 0.04 lb CO/MMBTU, and 0.015 lb VOC /MMBTU, and assume fuel heat content of 924 BTU/scf (gas provided from the Ryan/Holmes process de-methanizer). Emissions estimate for the emergency diesel generator were based on 960 hours of operation per year, emission factors listed in Table 3-52, a diesel fuel heat content of 137 MBTU/gal, and a fuel sulfur content of 0.5 weight percent. Diesel combustion CO_2 emissions were based on an EPA emission factor of 2778 grams of CO_2 per gallon of diesel combusted and an assumed combustion efficiency of 99 percent. Emissions from the flare were estimated based on an assumed combustion efficiency of 98 percent, AP-42 (1/95), emissions factors, and combustion of 16.85 MMscfy of pilot, purge, and residue gas with a heating value of 1,056 BTU/scf, and

0.33 MMscfy of propane with a heating value of 2,315 BTU/scf (Milligan, 2007). CO_2 emissions for flare gas combustion also assume 98 percent combustion efficiency, and use an emission factor of 134.46 lb CO_2 per MMBtu gas combusted. Condensate tank flashing emissions were estimated using the Vasquez-Beggs equation and a slop oil (water + oil) throughput of 9,400 barrels per year (70 percent H_2O). Milligan (2007) estimated that emissions from the other tanks were insignificant and those values were not quantified; this assumption has been maintained in this work. Condensate loading emissions (loading to tanker trucks) were estimated using a slop oil throughput of 9,400 barrels per year and an emission factor of 4.96 lb/1,000 gallons. Fugitive VOC emissions estimates were developed using the EPA's *1995 Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017) and the inventory of fugitive emissions sources listed in Table 3-53. It was assumed that emissions from the TEG dehydration unit are negligible since all vapors are recovered by a VRU and returned to the process inlet. Process blowdown emissions were developed based on an estimated 144 blowdowns with 8 Mscf fugitive emissions per blowdown, a molecular weight of 41.81 lb/lb-mole, and an estimated VOC content of 3.8 percent (Milligan, 2007).

Table 3-52 Summary of Combustion Equipment Used to Power Bas Processing Facility or Control Hydrocarbon Emissions

Description	Number of Units	Description	Hours of Operation Per Year	Fuel Type	Fuel Usage Rate	MMBtu/ Year/Unit	MMBtu/ Year For All Units	Height, (feet)	Diameter (inches)
Flare	1	Intermittent off-spec gas and blowdown combustion	N/A	Flare gas	1,209 MMscf/year	Not used for work	Not used for work	Not reported	
Turbine: Solar Saturn T-1300 (0perated at 465 °F)	2	1,151-hp (950 kW) rating	8,760	Natural Gas (924 Btu/scf)	12,900 scf/hr	104,416	208,831	40	54
Katolight Generator w/ Detroit Diesel Engine (operated at 825 °F)	1	1,096-hp (817 kW) rating	960	Low sulfur Diesel[a]	57 gal/hr	7,497	7,497	30	12
Hot Oil Heater	1	13.48 MMBtu/hr	8,760	Natural Gas (924 Btu/scf)	13.48 MMBtu/hr				
Superior 2416G Compressor Engine (operated at 728 °F w/OC)	2	3,200 hp	8,760	Natural Gas (924 Btu/scf)	23,896 scf/hr	118,085	118,085	45	24
Superior 2416G Compressor Engine (operated at 728 °F w/OC)[b]	3	2,800 hp	8,60	Natural Gas (924 Btu/scf)	20,909 scf/hr	193,420	386,840	45	24

[a]Diesel fuel higher heating value of 137 Mbtu/gallon, 500 ppm sulfur
[b]W/OC - with oxidation catalyst

Table 3-53 Sources of Fugitive Emissions from Gas-Processing Facility

Type of Equipment	Type of Service	Number Items
Valves	Gas/Vapor	1,592
	Light Liquid	837
	Heavy Liquid	186
Connectors	Gas/Vapor	6,368
	Light Liquid	3,348
	Heavy Liquid	744
Flanges	Gas/Vapor	1,592
	Light Liquid	837
	Heavy Liquid	186
Pump Seals	Light Liquid	9
	Heavy Liquid	6
Others[a]	Gas/Vapor	83
	Light Liquid	0
	Heavy Liquid	0

[a]Others include compressor seals, pressure relief valves, relief valves, diaphragms, drains, dump arms, hatches, instruments, meters, polished rods, and vents.

Table 3-54 Gas-Processing Facility Storage Tank Volumes

Description	Size (Gal.)
Process Drain Sump Tank	1,000
Diesel Tank	4,200
Lube Oil Tank	8,820
Ambitrol Tank	8,814
TEG Tank	4,200
Slop Oil Tank	19,740
Lube Oil (Day) Tank	1,000
Methanol	500
Methanol	500
Gasoline	500
Synthetic Lube Oil	500

Table 3-55 Gas-Processing Plant Engine Combustion Emission Factors

Name/Model	NO_X (g/hp-hr)	CO (g/hp-hr)	VOC (g/hp-hr)
1,151-hp Solar Saturn T-1300	2.30	2.60	0.05
1,096-hp Katolight Generator	10.78	3.42	0.28
3,200-hp Superior 2416G W/OC[a]	1.0	0.27	0.50
2,800-hp Superior 2416G W/OC	1.0	0.27	0.50
Superior 2416G W/O Controls	1.0	2.10	0.50

[a] *W/OC - with oxidation catalyst; W/O – without.*

Table 3-56 Estimation of Gas Processing Facility Emissions

Emissions Source	NO_X		CO		VOC		SO_2[a]		CO_2[b]
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	TPY
Flare[c]	---	0.63	---	3.43	---	1.30	---	0.53	1,223
NG Turbine	5.83	25.55	6.60	28.89	0.13	0.56	0.74	3.22	7,020
NG Turbine	5.83	25.55	6.60	28.89	0.13	0.56	0.74	3.22	7,020
Hot Oil Heater	1.08	4.72	0.54	2.39	0.20	0.89	0.83	3.64	7,939
Diesel emergency generator	26.04	12.50	8.26	3.97	0.68	0.32	4.01	1.93	166
3,200 hp Compressor Engine	7.05	30.90	1.90	8.34	3.53	15.45	1.36	5.97	13,004
3,200 hp Compressor Engine	7.05	30.90	1.90	8.34	3.53	15.45	1.36	5.97	13,004
2,800 hp Compressor Engine	6.17	27.04	1.67	7.31	3.09	13.52	1.19	5.22	11,378
2,800 hp Compressor Engine	6.17	27.04	1.67	7.31	3.09	13.52	1.19	5.22	11,378
2,800 hp Compressor Engine	6.17	27.04	1.67	7.31	3.09	13.52	1.19	5.22	11,378
Tank Working, Breathing, Venting Emissions	---	---	---	---	---	30.96	---	---	---
Blowdowns	---	---	---	---	---	2.41	---	---	---
Fugitives	---	---	---	---	---	56.99	---	---	---
Loading	---	---	---	---	---	0.98	---	---	---
Total	**71.23**	**211.09**	**30.59**	**105.30**	**17.45**	**166.43**	**12.61**	**40.14**	**83,343**

[a] Based on a fuel sulfur content of 343 ppmv (57 lb SO_2/MMscf) except for the diesel engine which is based on fuel sulfur content of 0.5 %S.

[b] Based on CO_2 emissions factor of 13.446 lb CO_2 /BTU of natural gas and 2778 grams CO_2 per gallon of diesel consumed with 99% diesel combustion efficiency

[c] Natural gas flare CO_2 emissions assumes combustion efficiency of 98% as estimated by Milligan (2007)

3.9.1.5 *Estimating Separation Efficiency of the Ryan-Holmes Process*

Removal efficiency of hydrocarbon constituents through the Ryan Holmes process is estimated based on data provided in n report entitled *List of Acid Gas Removal Processes* (no authors listed) and citing a presentation by Ryan and Schaffert (1984). Based on these data, reported in Table 3-57, an estimated methane recovery to fuel gas of 93 percent, CO_2 recovery to recycle stream of over 90 percent, and hydrogen, ethane, propane, and butanes fraction recoveries to NGL product of about 100 percent, 93 percent, 100 percent, and 99 percent, respectively. A two column Ryan-Holmes propane recovery process at the Chevron Buckeye CO_2 Plant (Garner, 2008) has a reported methane recovery rate of 7 percent, by mass (estimated by dividing the difference between PRC inlet and outlet mole percentage of each constituent by the inlet mole percent composition). This low methane recovery efficiency is considered to be too low to be applied to gas streams with significant recoverable methane content.

Table 3-57 Ryan/Holmes Process Influent Gas and Effluent Vapor and Liquid Molar Flow Rates (moles/hr)

Constituent	Feed Gas Flow Rate, moles/hr	Fuel Gas Product Flow rate, moles/hr	CO_2 Recycle Stream Flow rate, moles/hr	NGL Production Rate, moles/hr
CO_2	793.3	4.2	715.1[a]	20
H_2	5	-	4 ppm	5
CH_4	214.2	199.2	15	-
C_2H_6	110.9		8	102.9
C_3H_8	94.8	0.1	0.3	94.4
C_4	116.8	0.7	-	116.1
N_2	3.1	3.1	-	-
Total	**1338.1**	**207.3**	**738.4**	**338.4**

Referenced from Ryan and Schaffert

[a]Reported value of 715.1 moles/hour was adjusted to 769.1 moles per hour to ensure molar balance between process streams.

These values were used to estimate gas-processing plant mass separation efficiency. Table 3-58 reports mass percent of influent flow reporting to each process stream.

Table 3-58 Calculated Gas Separation Efficiency of Ryan-Holmes Process (percent mass)

Constituent	Mass Percent of Influent Stream Reporting to Fuel Gas (% mass)	Mass % Influent Stream Reporting to CO_2 Recycle Gas (% mass)	Mass Percent of Influent Stream Reporting to NGL Stream (% mass)
Carbon Dioxide (CO_2)	0.5	97.0	2.5
H_2	0.0	0.00	100.0
Methane (C_1)	93.0	7.00	0.00
Ethane (C_2H_6)	0.0	7.2	92.8
Propane (C_3H_8)	0.1	0.3	99.6
Butanes(C_4)	0.6	0.0	99.4
Nitrogen (N_2)	100.0	0.0	0.0

These calculated percent recovery estimates were modified to include other constituents that are in the previously-reported gas analysis estimate developed from the Nehring Database (2007). Modifications include addition of pentane and hexane plus fractions based on an assumption of 100 percent of these heavy fractions reporting to the NGL product stream, removal of H_2 (no H_2 content is reported in Nehring Database), and addition of helium based on the assumption that 100 percent, by mass, of helium is retained in the gas fraction and returned to the CO_2-EOR flood in the CO_2 stream.

Table 3-59 Estimate of Mass Allocation of Each Influent Gas Constituent Fraction Between Products of the Gas Processing Facility

Constituent	Mass Percent of Influent Reporting to Fuel Gas (% mass)	Mass Percent Influent Reporting to CO_2 Recycle Stream (% mass)	Mass Percent of Influent Reporting to NGL Stream (% mass)
Carbon dioxide (CO_2)	0.5	97	2.5
Helium (He)	0.0	100	0.0
Methane (C_1)	93	7	0.0
Ethane (C_2H_6)	0.0	7	93
Propane (C_3H_8)	0.1	0.3	99.6
Butanes(C_4)	0.6	0.0	99.4
Pentanes (C_5)	0	0	100
Hexanes Plus (C_{6+})	0	0	100
Nitrogen (N_2)	100	0.0	0.0

It is assumed that the H_2S concentration in the CO_2-EOR produced gas is negligible in all scenarios considered in this report. In cases where significant concentrations of H_2S are present in the produced gas, it would be possible to separate it as a pure stream in the gas-processing facility, and dispose of it in a UIC Class I disposal well. An alternative to disposal would be oxidation in a Claus plant to produce elemental sulfur and water. Neither option is considered further herein. Based on these estimates of gas mass percent composition, and calculated mass flow of total gas (hydrocarbon gas + CO_2) collected from CO_2-EOR operations, estimates of gas processing plant product mass flow rates and compositions were developed (Table 3-60).

Table 3-60 Average Mass Composition of Gas Recycled to CO_2-EOR Operations

Constituent	Recycled CO_2 Stream Mass Fraction (%)
Methane	0.7
Ethane	0.7
Propane	0.0
Butane	0.0
Pentane	0.0
Hexane	0.0
Nitrogen	0.0
Carbon Dioxide	98.6
Helium	0.0

Table 3-61 Estimation of Natural Gas and Natural Gas Liquids Production from Ryan-Holmes Process

HC Stream	Units	Historical	Best Practices	1.5 HCPV WAG
Fuel Gas	Btu/lb, HHV	19,600	18,200	17,100
	MMBtu/short ton	39.3	36.3	34.2
	btu/scf[a]	818	758	713
	MMBtu of natural gas produced per pattern-year	7,690	8,260	6,860
	MMscf natural gas equivalent produced per pattern-year[b]	7.54	8.09	6.72
Natural Gas Liquids	Btu/lbm, HHV	6,900	4,300	3,300
	MMBtu/short ton	13.8	8.67	6.60

[a]Assumes density of 0.417 lb/ft^3 at 20 °C, 1 atmosphere
[b]Based on natural gas higher heating value of 1020 btu/scf
All values reported as higher heating value unless otherwise noted.

Table 3-62 Mass of Constituents Separated from CO_2-EOR Recycle Stream Through Ryan-Holmes Process

Constituent	Mass Separated Over Life of CO_2-EOR Flood per Well Pattern, Short Tons		
	Historical CO_2-EOR	Best Practices CO_2-EOR	1.5 HCPV WAG CO_2-EOR
Natural Gas			
Methane	18,500	25,300	29,900
Carbon Dioxide	700	2,100	3,500
Helium	0	-	-
Nitrogen	1,900	2,600	3,100
Average HHV of NG mix over lifetime of flood (MMbtu/ton)	41.9	40.2	39.1
Natural Gas Liquids			
Propane	1,160	1,583	1,869
Butane	377	514	607
Pentane	151	206	243
Hexane	74	101	119
Hydrogen Sulfide Product			
Hydrogen Sulfide	19	26	30

3.9.1.6 Displacement Credit for Energy Coproducts

In addition to production of the primary crude oil product of CO_2-EOR activity, natural gas and natural gas liquids are also generated as coproducts. In determining the environmental life cycle profile associated with gate-to-gate activities associated with production of crude oil, the benefit associated with production of these coproducts should be credited to the profile of the primary product. The credit associated with each coproduct is equivalent to the environmental profile associated with production and delivery of a product of equivalent function that is obviated by the production of the coproduct. For purposes of this study, it has been assumed that natural gas liquids generated as a coproduct of CO_2 recycle/gas processing activity displace production of natural gas liquids generated through natural gas processing and "light ends" generated from refinery operations, and that natural gas coproduct is accounted for by taking a credit for the displaced production of natural gas generated from domestic offshore production. Amounts of coproduct generated are reported on a MJ basis; emissions credits for the production of these amounts of coproducts are incorporated into reported gate-to-gate environmental profile of crude oil production. As an alternative to displacement, one could describe the CO_2-EOR performance in terms of emissions per unit of total energy product generated (the sum of crude, natural gas, and natural gas liquids production). In this case, the primary product is total hydrocarbon energy products (reported in units of MJ or barrels of oil equivalent), and no displacement credit for coproducts would be applied.

Accounting for Natural Gas Liquids Coproduct

Characterization of natural gas liquids for development of displacement credit estimate is based on the 2008 NETL Petroleum Baseline report data and assumes a 50/50 mix of natural gas liquids and refinery "light ends" based on EIA estimates that U.S. Production of propane/propylene is approximately half from refinery and half from natural gas production operations. NGL includes butane, propane, ethane, etc. produced along with natural gas. Refinery "light ends" includes LPG, refinery still gas and some chemical plant feedstocks. Both are appropriate representations of LPG. Density of LPG is assumed to be 86.2 kg/bbl (U.S. DOE, 2008). Table 3-63 provides a summary of GHG emissions associated with production and delivery of these two comparable products. Averaging these two GHG emissions profiles, the cradle-to-gate GHG emissions value for use as an NGL displacement credit is calculated to be 41.1 kg CO_2-E per bbl of LPG or 0.477 kg CO_2-E per kg of LPG.

Table 3-63 Displacement Credit for Natural Gas Liquid Coproducts of Oil Production in CO_2-EOR Estimated as the Average of Domestic Refinery Light Ends and NGLs Produced at a Gas-Processing Plant

Pollutant	Units	Refinery Light Ends Cradle-to-Gate of refinery	Natural Gas Liquids Cradle-to-Gate of natural gas processing plant
CO_2	kg / bbl liquefied gas	60.9	5.33
CH_4	kg / bbl liquefied gas	0.515	0.105
N_2O	kg / bbl liquefied gas	1.30E-3	2.88E-4
CO_2E	kg / bbl liquefied gas	74.2	8.04
CO_2E	kg / kg LPG	0.861	0.0933
Contribution to overall (national average) profile	%	50	50

Accounting for Natural Gas Coproduct

Composition and volume of natural gas generated as a coproduct of CO_2-EOR operations is the sum of gas collected from tank battery vapor and gas processing facility minus that which is used in CO_2-EOR operations. Any amount not consumed in CO_2-EOR operations is considered to be coproduct, and a credit is taken based on the amount of coproduct that is sold to the market. Only the historical CO_2-EOR operational scenario results in excess natural gas production, with 0.75 million standard cubic feet of 1020 btu/scf HHV net natural gas production per pattern year. Best practices and high-CO_2 injection scenarios consume more natural gas than they produce, requiring 0.66 MMscf and 1.38 MMscf 1020 btu/scf HHV net natural gas, respectively. In these scenarios, the same emissions profile as used to apply a credit in the historical case would be used to calculate upstream emissions associated with natural gas that would need to be purchased to supply CO_2-EOR operations. The emissions profile for natural gas is based on a purchased, proprietary dataset and cannot, therefore, be reported.

3.10 Facility Closure and Decommissioning

Following CO_2-EOR, it is assumed that no additional oil recovery or CO_2 sequestration operations will be carried out at the site. Facility closure operations include plugging and abandonment of wells, removal of injection and production equipment, re-contouring of well pad, removal of unneeded access roads, and site re-vegetation. In this analysis, resource requirements and emissions associated with well plugging operations; emissions and resource requirements associated with EOR infrastructure removal and site reclamation (regarding any re-vegetation) have not been considered. Also, it has been assumed that no spills or subsurface contamination occurred as a result CO_2-EOR operations, and no site remediation is required.

3.11 Plugging and Abandonment of Wells

Potential conduits for leakage of CO_2 to the surface or subsurface water resources must be plugged following completion of injection operations, including any injection wells or extraction wells. Monitoring wells should also be plugged following completion of the monitoring and verification period. Plugging wells involves placement of cement plugs in areas along the depth of the well that are considered to be critical to the protection of drinking water zones (USDWs), prevention of injectate leakage to the surface, prevention of subsurface crossflow of fluids, and protection of correlative rights. Because of the required permanence of storage, a more complete plugging may be required as compared to other types of wells, such as traditional oil wells.

3.11.1 Cementing Operations

Cement is applied to the well using a truck-, trailer-, or skid-mounted cement pumping system. It has been assumed that a double pump, trailer-mounted system is delivered to and used onsite for all well cementing operations. Review of specifications for commercially available cement pumping systems suggests that a system with two 475 horsepower diesel deck engines is appropriate (Rolligon, CPF-800D Double Pump Cementing Trailer). To estimate emissions from cementing operations, it is assumed that both of the cement truck deck engines will be in operation 12 hours a day for an estimated 3 days of cementing per well (Watson et al., 2002).

For wells 5,826 feet in depth, and reservoirs of 123 °F, API Class A Portland Cement is specified with 46 percent water by weight (5.2 gallons of water per 94 lb sack of cement). Mass of cement required for plugging operations is estimated based on the assumption that the volume inside the innermost casing is filled with cement for a column height of double the target interval thickness, plus a surface plug of 200 feet thick.

Table 3-64 Summary of Cement Pumping Specifications for Well Plugging Operations

Parameter	Value	Units
Days of cementing per well plug	3	days
Hours of cementing per well plugged	36	hours per well plugged
Number of engines per cement rig	2	engines
HP of cementing deck engines	475	HP/engine
Load Factor	0.75	Unitless
Wells per pattern	2	Wells
Diesel fuel used per plugged pattern	10,180 (2,690)	Liters (gallons)

Table 3-65 Emissions from Cementing Truck Deck Engines Reported on a Per-Pattern Basis (two wells per pattern)

Constituent	Value	Units
Total Hydrocarbon	8.6	kg HC per pattern
CO	68.1	kg CO per pattern
NO_X	128.2	kg NO_X per pattern
PM Total	3.3	kg PM Total per pattern
PM10	3.2	kg PM10 per pattern
PM2.5	0.1	kg PM2.5 per pattern
CO_2	27,215	kg CO_2 per pattern
SO_2	0.0018	kg SO_2 per pattern
Cement Demand	56.7	Metric tonnes cement per pattern
Water Consumed	26.1	Metric tonnes water per pattern

3.12 Site Monitoring, Verification, and Assessment

NETL has established geologic storage permanence goals of demonstrating 95 percent and 99 percent CO_2 retention by 2008 and 2012, respectively. This corresponds to maximum leakage of one and five percent of injected CO_2 after 100 years of storage. Demonstrating that geologic sequestration can meet these goals requires that effective techniques be available to measure any potential leakage. A number of techniques have been developed to monitor CO_2 plume migration, verify CO_2 reservoir storage integrity, and account for the amount of CO_2 that remains sequestered in a target geologic formation. These site monitoring, verification, and accounting (MVA) methods involve application of atmospheric, near-surface, and subsurface monitoring techniques that, in combination, demonstrate to both regulatory oversight bodies and the general public that geologic sequestration of CO_2 can serve as a safe and effective GHG control strategy.

While CO_2-EOR methodology has employed some sophisticated reservoir surveillance to assure that CO_2 was performing its intended function, it has not historically employed MVA techniques to a degree that may be required for sequestration. Thus, it is assumed that, going forward, increased monitoring of CO_2-EOR facilities will become more robust so that the operator can claim a credit for storage of CO_2. As such, a simplified characterization of CO_2-EOR monitoring has been incorporated. This characterization assumes that the same technologies and areas of review are used to survey the site as was detailed in the site characterization description, but that two surveys are performed instead of one: one at the time of site closure, and a second survey at some point after site closure. A revised characterization of MVA activity should be considered as additional detail on likely techniques and monitoring schedules become available.

4.0 Results and Discussion

Results of modeled single well performance and full EOR facility performance for three CO_2-EOR operational scenarios are discussed with respect to environmental performance, resource demand, crude oil production, byproduct and coproduct production, and trends observed with increasing CO_2 injection.

4.1 Single CO_2-EOR Well Pattern Performance

For each CO_2-EOR operational scenario, performance was estimated based on stream-tube modeling of tapered water alternating gas (WAG) CO_2/brine injection in a post-water flood, Permian Basin-type reservoir conditions. The model is based on a tapered WAG CO_2/brine injection using a standard 40-acre, five-spot well pattern (1:1 injection: production well ratio) using reservoir, fluid, and injection parameters as detailed in Section 3. Fluid injection and production performance profiles generated from the stream-tube model have been used as the foundation on which surface activity estimates are based. For example, the volume of liquids (crude oil and brine) produced from a single CO_2-EOR pattern is used to estimate the size of processing equipment required. Emissions and energy requirements of this processing equipment were estimated based on equipment size and volumetric throughput. Table 4-1 provides a summary of CO_2-EOR 40-acre, 5-spot well pattern performance for each operational scenario. On an absolute basis, both crude oil production and CO_2 retention are shown to increase with increasing CO_2 injection. Considering only flood performance data suggests that increased CO_2 injection will provide the best option for both CO_2 storage and oil production. Subsequent discussion of gate-to-gate life cycle environmental performance provides a more complete perspective on CO_2-EOR flood performance, which leads to a different conclusion about the relative merit of these CO_2-EOR operational scenarios for crude oil production and environmental performance.

Table 4-1 Summary of CO_2-EOR Flood Performance for the Operational Scenarios Defined Herein, and Predicted Using the CO_2 Prophet Stream-tube Model

CO_2-EOR Scenario	HCPV CO_2 Injected	Oil Recovery		Cumulative Excess Brine Production, MSTB per Well Pattern	CO_2 Stored Per Pattern, Metric Tonnes
		% OOIP	MSTB per Well Pattern		
Historical	0.4	11.6	191.4	100.8	38,200
Best Practices	1	17.4	301.7	246.0	70,300
High CO_2 Injection	1.5	20.9	360.9	240.0	77,800

4.1.1 CO_2 Retention Performance of Single Well Pattern

Performance of the CO_2-EOR flood as predicted by the CO_2 Prophet model shows that the stimulation of oil production is greatest in early years of flooding. Similarly, storage of CO_2 in the formation is greatest early in the CO_2-EOR flood, with very little additional storage achieved in later years (for the CO_2-EOR operational scenarios considered). In Figure 4-1, cumulative mass of CO_2 sequestered (calculated as the difference between cumulative CO_2 injected and produced) is plotted as a function of time for each of the three CO_2-EOR operational scenarios considered.

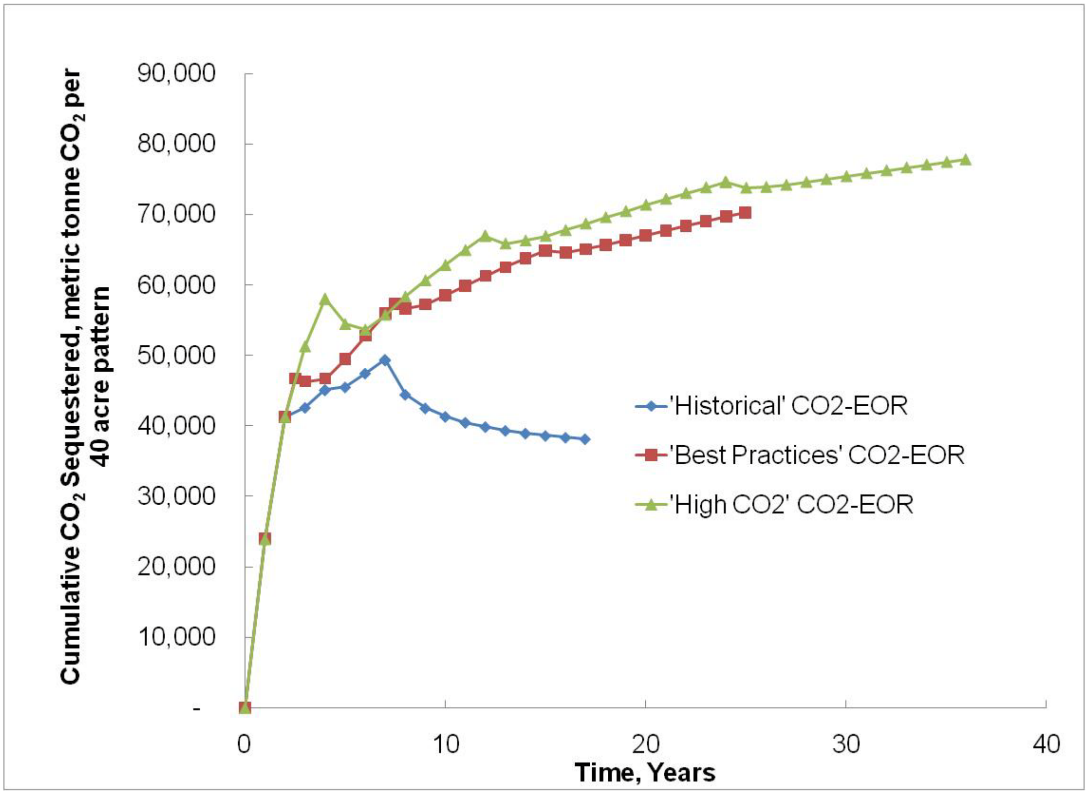

Figure 4-1 CO_2 retained in a single 40-acre, five-spot CO_2-EOR pattern for the three described operational scenarios. Retention is greatest in early years of flood operation. Water slug applied after WAG in the historical scenario recovers about 23 percent of stored CO_2, by mass.

In all CO_2-EOR operational scenarios, the bulk of the geologic storage potential is realized early in the WAG injection; data reported in Table 4-2 further detail this observation.

Table 4-2 Summary of Single Pattern CO_2 Retention Performance. In all operational scenarios, 75 percent of maximum CO_2 storage potential is realized in the first third of flood operation.

	Historical	Best Practices	1.5 HCPV CO_2 WAG
Years to 50% of max. retention	1	2	2
Years to 75% of max. retention	2	6	8
Pattern Life (years)	17	25	36
Max retention (metric tonnes CO_2)	49,500	70,300	77,800
Ultimate retention[a]	38,200	70,300	77,800

[a]Historical CO_2-EOR scenario includes post WAG injection water slug to recover CO_2, so the mass of CO_2 ultimately retained is less than the maximum that was stored prior to water slug injection.

Figure 4-2 illustrates the CO_2 sequestered at the end of the flood as a function of the total amount of CO_2 injected. This plot illustrates the trend of diminishing CO_2 storage benefit with higher CO_2 throughput. Portions of the reservoir that have been swept with CO_2 earlier in the flood take up less additional CO_2 as the injection proceeds. Since high CO_2 throughput is also associated with increased gas processing activity, higher CO_2 injection scenarios also tend to have higher operational GHG emissions. Based on these preliminary observations, reconsideration of high HCPV WAG CO_2 injection alone as a scheme to enhance CO_2 storage may be warranted.

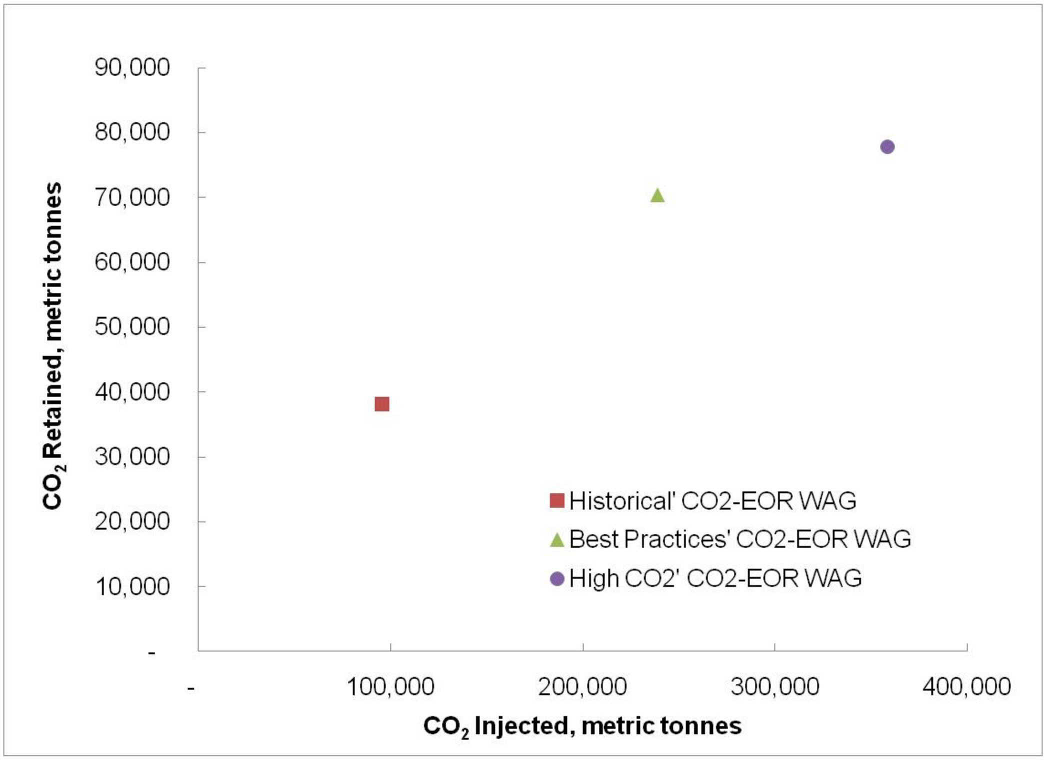

Figure 4-2 Mass of CO_2 Sequestered per 40-Acre, Five-Spot as a Function of the Mass of CO_2 Injected. Additional storage benefit decreased with increasing CO_2 injection.

This figure shows that about forty percent of the injected CO_2 is retained per pattern in the 0.4 HCPV CO_2 injection historical scenario, about 29 percent of injected CO_2 is retained per pattern in 1.0 HCPV "best practices" scenario, and about 22 percent of injected CO_2 is retained in the

1.5 HCPV CO_2-EOR scenario. The volume not retained is not vented to the atmosphere, but rather recycled for use in CO_2-EOR operations. Ultimately, close to 100 percent of purchased CO_2 will be stored geologically.

4.1.2 CO_2 Recovery in Historical Scenario

In the historical CO_2-EOR scenario, CO_2 use is kept low in order to minimize the expense of purchased CO_2. In addition, at the end of the CO_2 WAG injection, an additional slug of water is injected (assumed 1 HCPV of water) in order to recover as much of the oil and CO_2 as economically possible from the reservoir. The oil is sold and the CO_2 is reused in nearby patterns still undergoing active injection. The cumulative storage profile of the historical CO_2-EOR scenario illustrates the effect of this water slug injection to recover CO_2. Approximately 27 percent of the sequestered CO_2 is recovered by post-WAG injection of a 1.0 HCPV water slug. From a CO_2 sequestration perspective, this technique both decreases the storage of CO_2 per pattern and has associated emissions from production and delivery of electricity used to compress and inject water, and would not be applied in situations where maximizing sequestration of CO_2 is a goal.

4.2 Life Cycle Performance

Modeled single well performance results were used as the basis on which CO_2 and brine injection, fluid production, and processing activity estimates were based. The amount of CO_2 and brine injected were estimated based on the prescribed WAG injection schedule detailed in Section 3, and the ratio of recycled to purchased CO_2 feeding CO_2-EOR operations was estimated based on the difference between what was required for injection and what was produced for recycle. Based on the volume and pressure of each CO_2 feed stream, CO_2 boost compression energy requirements were estimated as described in Section 4. Similarly, volume of brine required for WAG operations and volume of brine produced through WAG operations were used as the basis for estimation of brine compression energy requirements both to feed WAG operations and to dispose of excess brine through injection well disposal. Liquid and gas products were assumed to be separated at a satellite separation facility and liquid products (oil and brine) are assumed to be collected from 10 well patterns to be processed at a tank battery. Produced gas moves from the separation satellite to a gas-processing facility located adjacent to CO_2-EOR flood operations where the gas stream undergoes distillative separation to remove HC as natural gas and natural gas liquids from CO_2.

The following sections summarize results of a gate-to-gate characterization of tapered water alternating gas CO_2-EOR operations. Environmental performance parameters considered include GHG emissions, criteria air pollutant emissions, water consumption, land use, and net energy yield.

4.2.1 Greenhouse Gas Emissions

Estimates of CO_2-EOR flood GHG performance were developed based on procedures outlined in Sections 3 and 4. Figure 4-3 illustrates the life cycle GHG emissions performance of each CO_2-EOR operational scenario broken out on a per-phase basis. (Phases of operation are here defined as site evaluation and characterization, facility construction, CO_2-EOR flood operation, site closure, and post-closure MVA.) These results are presented on a per-barrel of oil basis. Natural gas and natural gas liquids coproducts have been accounted for by applying an emissions credit for displacement of equivalent product, as described in Section 3.5.3.5.

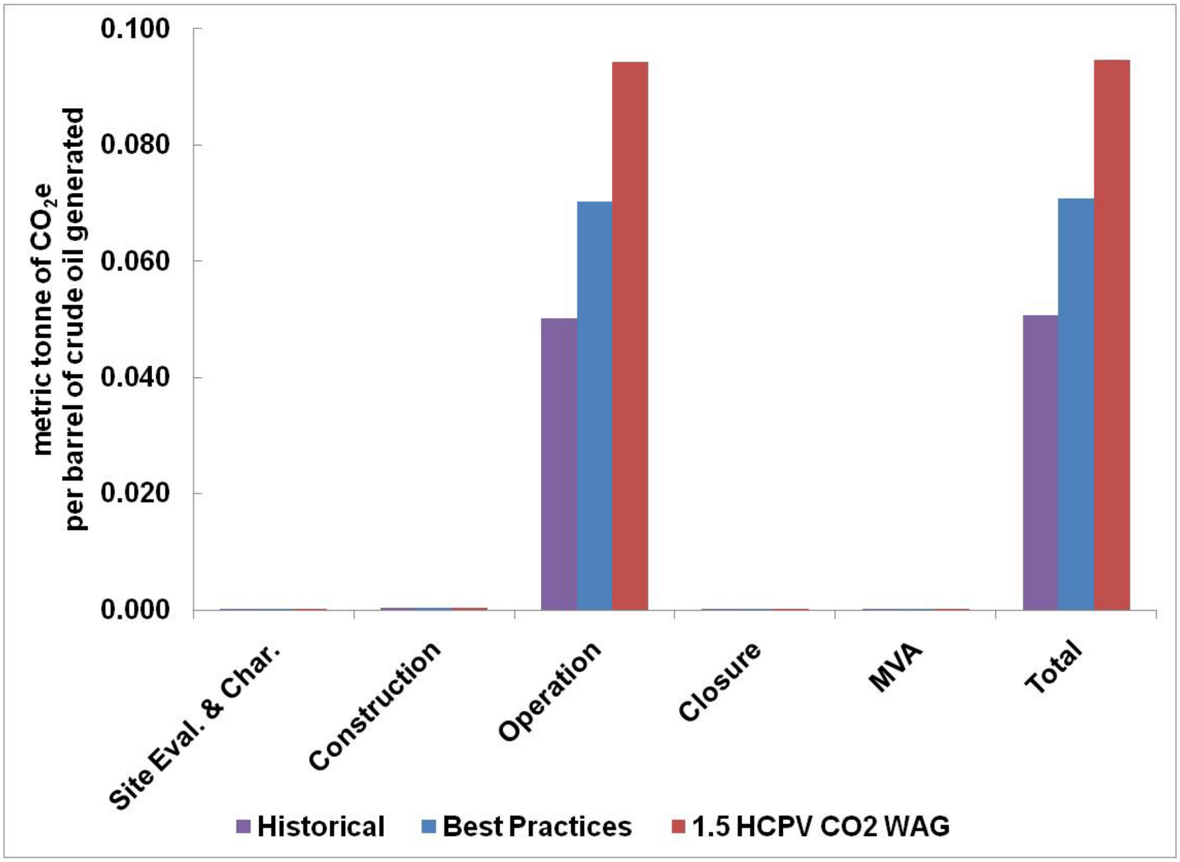

Figure 4-3 Summary of Life Cycle Greenhouse Gas Emissions Associated with Each Phase of CO_2-EOR Activity, Reported in Units of Metric Tonnes of CO_2-Equivalent Generated per Barrel of Oil Produced

From this figure it can be seen that nearly all (99%) GHG emissions associated with CO_2-EOR overall activity occur during the operational phase, for all operational scenarios considered. In addition, this figure also shows a correlation between the amount of CO_2 injected and the operational phase GHG emissions. This correlation can be attributed, in large part, to the increase in emissions associated with increased gas processing required when larger volumes of CO_2 are loaded to, and recycled from, the CO_2-EOR flood. Figure 4-4 illustrates the total life cycle emissions for each operational scenario as compared to total CO_2 sequestered through CO_2-EOR activity, reported per barrel of oil produced. Life cycle emissions include credit taken for any natural gas liquids and natural gas coproducts that are not consumed onsite in CO_2-EOR operations.

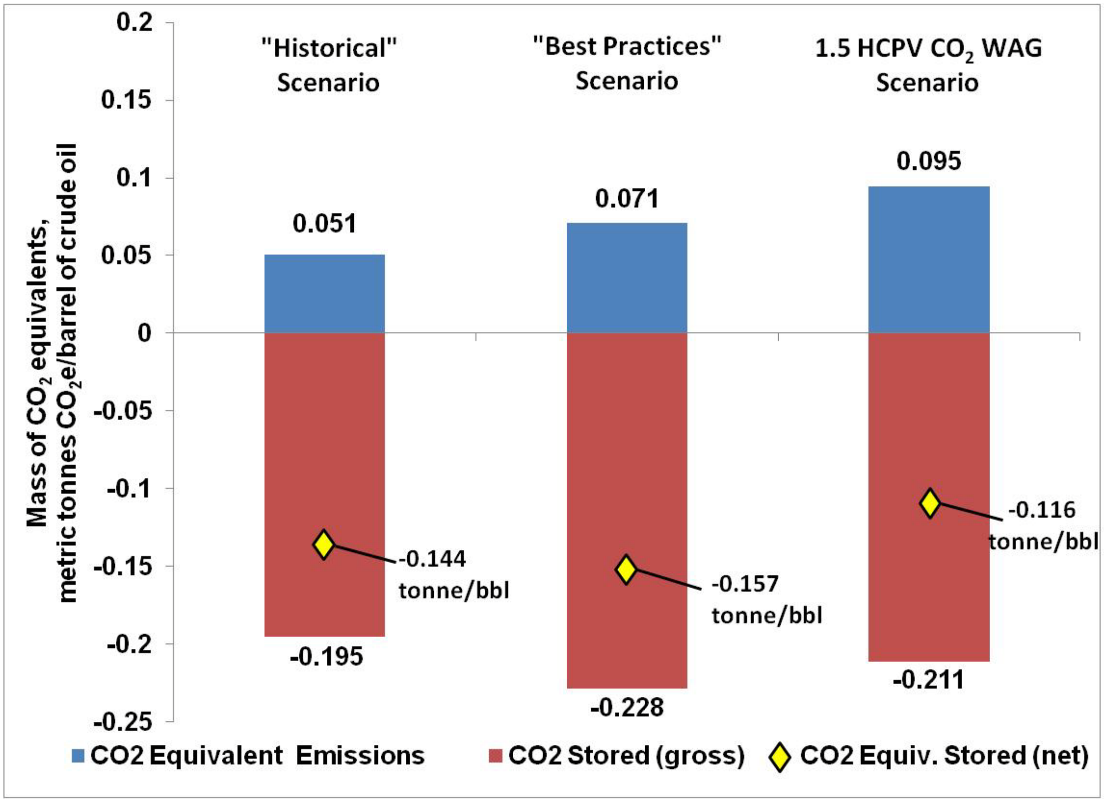

Figure 4-4 Total Gate-to-Gate Life Cycle Emissions for Each Operational Scenario and Total CO_2 Sequestered Through CO_2-EOR Activity (both reported per barrel of oil produced)

From Figure 4-4 we see that net and gross CO_2 storage per barrel of oil produced is greatest in current "best practices" WAG scenario and the 1.5 HCPV CO_2 WAG exhibits the lowest net sequestration benefit per barrel of oil produced.

4.2.2 **Criteria Air Pollutant Emissions**

Similar to GHG emissions, criteria air pollutants associated with the operational phase of CO_2-EOR activity are significantly higher than those of other phases of activity. Results of the criteria air pollutant inventory for the Best Practices operational scenario are plotted in Figure 4-5. The other two operational scenarios show similar trends, with emissions being less in the historical (low-CO_2 injection), and greater in the 1.5 HCPV CO_2 injection scenario. Plots of these data are not shown, but results are summarized in tabular form in Appendix H. One noteworthy exception is the total particulate matter emissions, which are greatest in the construction phase as a result of dust generated from construction, well workover, and related equipment mobilization activities. Volatile organic carbon (non-methane) emissions are primarily from working, breathing, and venting losses in the tank battery operations, and fugitive losses in the satellite separator, tank battery, and gas processing facility.

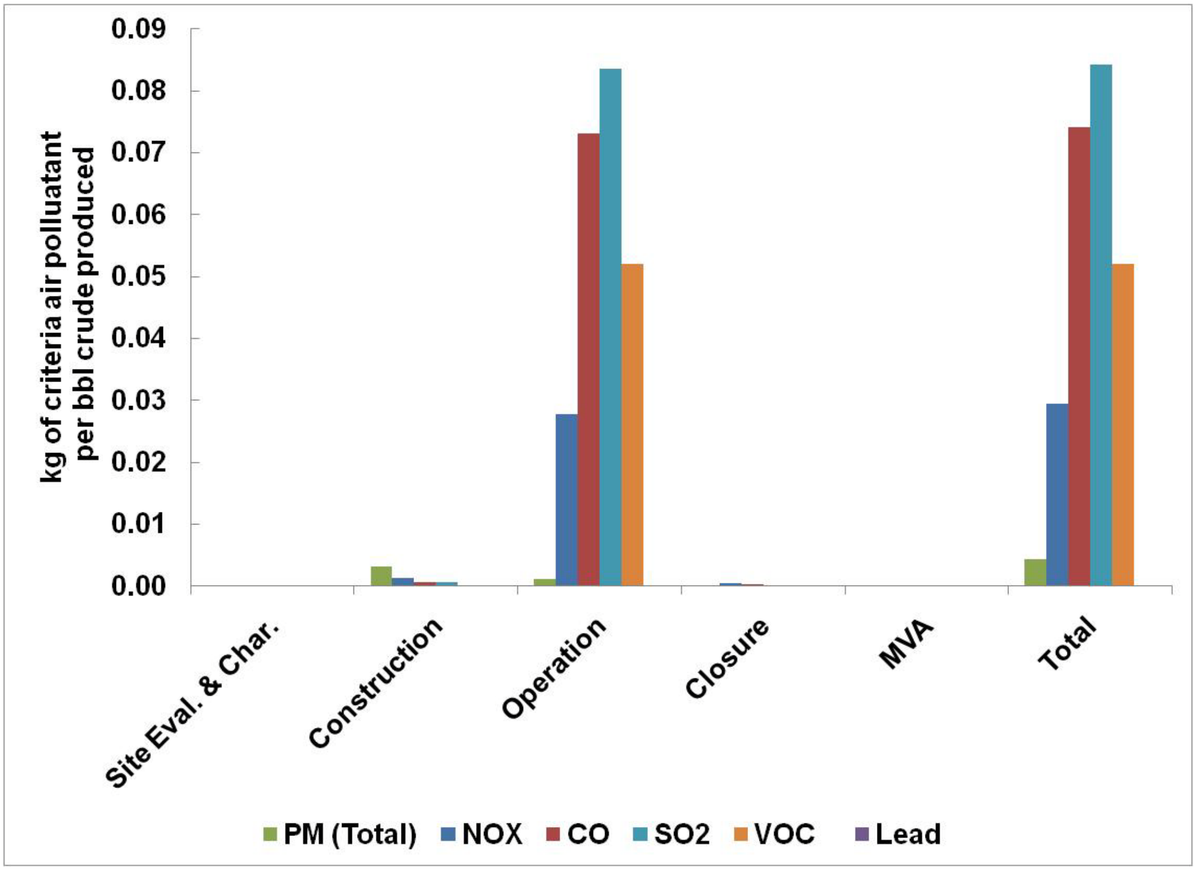

Figure 4-5 Summary of Criteria Air Pollutant Emissions Associated with Each Phase of CO_2-EOR Activity for the Best Practices Operational Scenario, Reported in Units of Metric Tonnes of Pollutant Generated per Barrel of Oil Produced

Relative magnitude of emissions of different criteria air pollutants cannot be directly compared because the impact on human health or the natural environment associated with each constituent may be significantly different. This type of impact analysis is not within the scope of this study.

4.2.3 Land Use

Only land directly affected by CO_2-EOR activity is included in this estimate, including all land occupied by CO_2-EOR flood patterns plus an estimated 8 hectares (20 acres) of land on which the gas processing facility is constructed. Land use associated with upstream activities, such as coal mining performed to generate coal that is used to produce electricity delivered to and used in CO_2-EOR operations, is not included. It should be noted that a large fraction of the land below which a CO_2-EOR flood is in operation can remain functional for a variety of activities such as farming and grazing. As such, the estimates of direct land use reported herein are considered to be conservative. Table 4-3 summarizes estimated land in service for EOR flood and related processing activities, reported on an acres/bbl of crude oil basis.

Table 4-3 Estimated Acres of Land Disturbed by CO_2-EOR Activity per Barrel of Oil Produced

CO_2-EOR Scenario	Land Use, Acres/bbl Crude
Historical	2.09×10^{-4}
Best Practices	1.33×10^{-4}
1.5 HCPV CO_2 WAG	1.17×10^{-4}

Because a specific reservoir within the Permian Basin was not identified for this study, specific land type impacted as a result of CO_2-EOR activity could not be specified. United States Department of Agriculture land resource type designation for the Permian Basin is either Central Great Plains or Western Range.

4.2.4 **Water Use**

Total water consumption in CO_2-EOR operations is estimated to be in the range of 0.2 - 0.25 times the volume of produced oil (on a volume/volume basis). Figure 4-6 shows that water is consumed primarily in the operational phase of CO_2-EOR activity, with small amounts of water consumption associated with workover and well plugging operations in the construction and site closure phases, respectively. Nearly all of this water consumption (greater than 95% in all cases) is associated with electricity production as purchased from the grid; direct water consumption associated with on-site activity at the CO_2-EOR facility is very low.

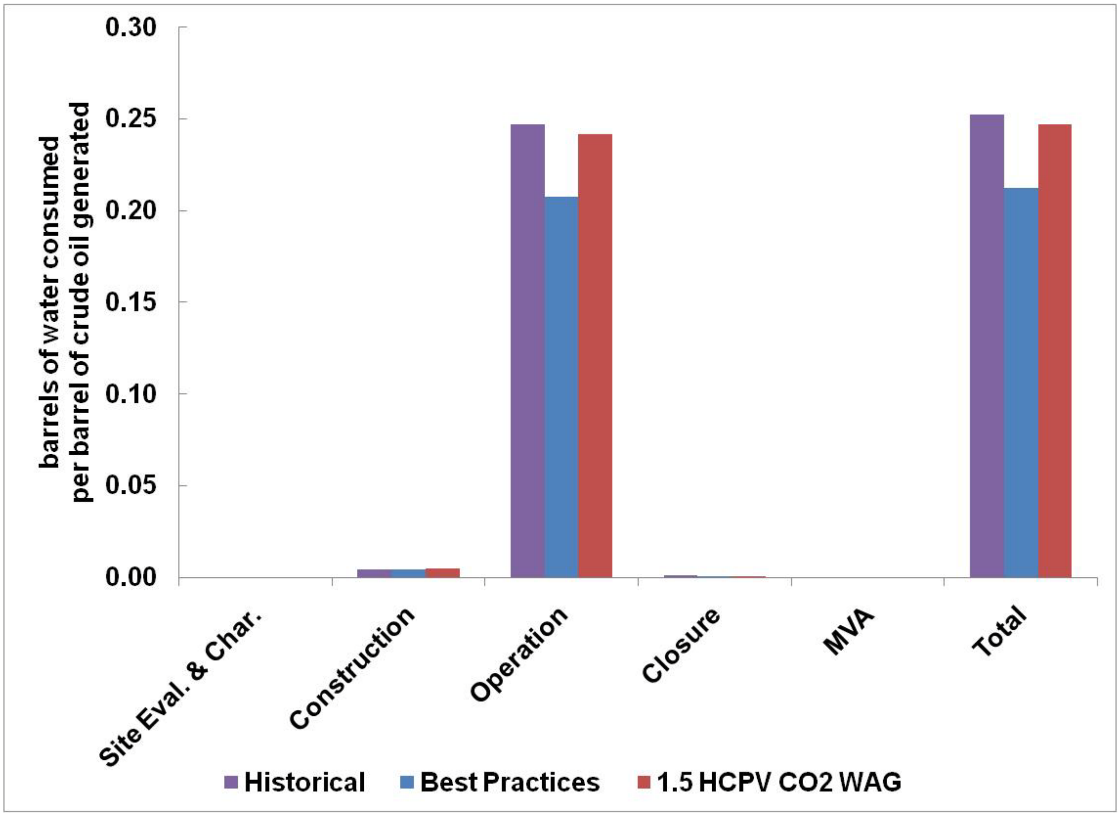

Figure 4-6 Water Consumption Associated with Each Phase of CO_2-EOR Activity for Each Operational Scenario (barrels of water consumed per barrel of oil produced)

4.2.5 Gross and Net Energy Yield

Energy products of CO_2-EOR activity are crude oil, natural gas and natural gas liquids produced in the gas processing plant, and higher energy content hydrocarbon gas collected from tank battery vapors. A portion of the gross energy products generated through CO_2 EOR activity will be consumed in the operation of the liquid and gas processing operations, as detailed in Section 4. Specifically, some or all of the natural gas generated through gas processing and some of the hydrocarbon vapor collected by tank battery vapor recovery units will be used for operations such as gas compression, on-site electricity (electricity used in the gas- processing facility), and fueling of the fire tube boiler used in heater/treater operations. Net energy products are, therefore, the difference between gross energy products generated on site, and the amount of natural gas products that are consumed in the course of facility operations. Figure 4-7 and Figure 4-8 show the gross and net energy product slate, respectively, for the three operational scenarios.

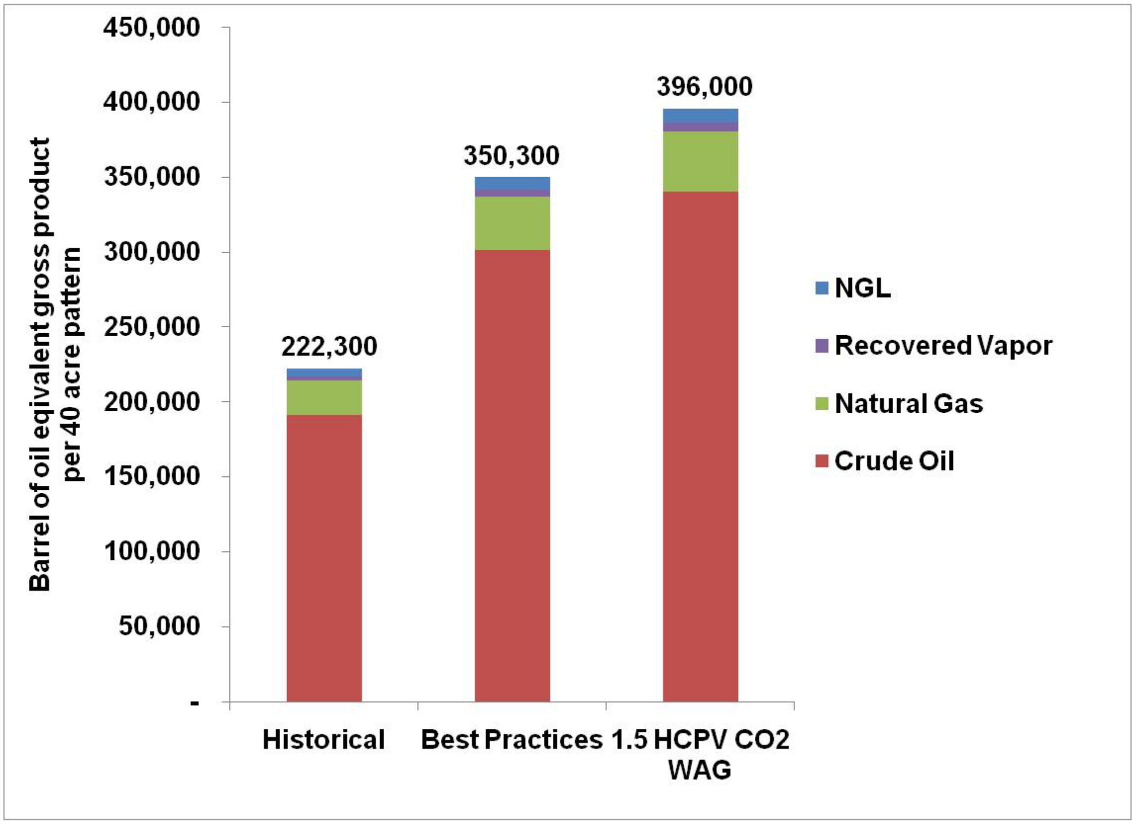

Figure 4-7 Gross Hydrocarbon Products Generated per 40 Acre Well Pattern in Each CO_2-EOR Operational Scenario (barrel of oil equivalents per 40 acre pattern)

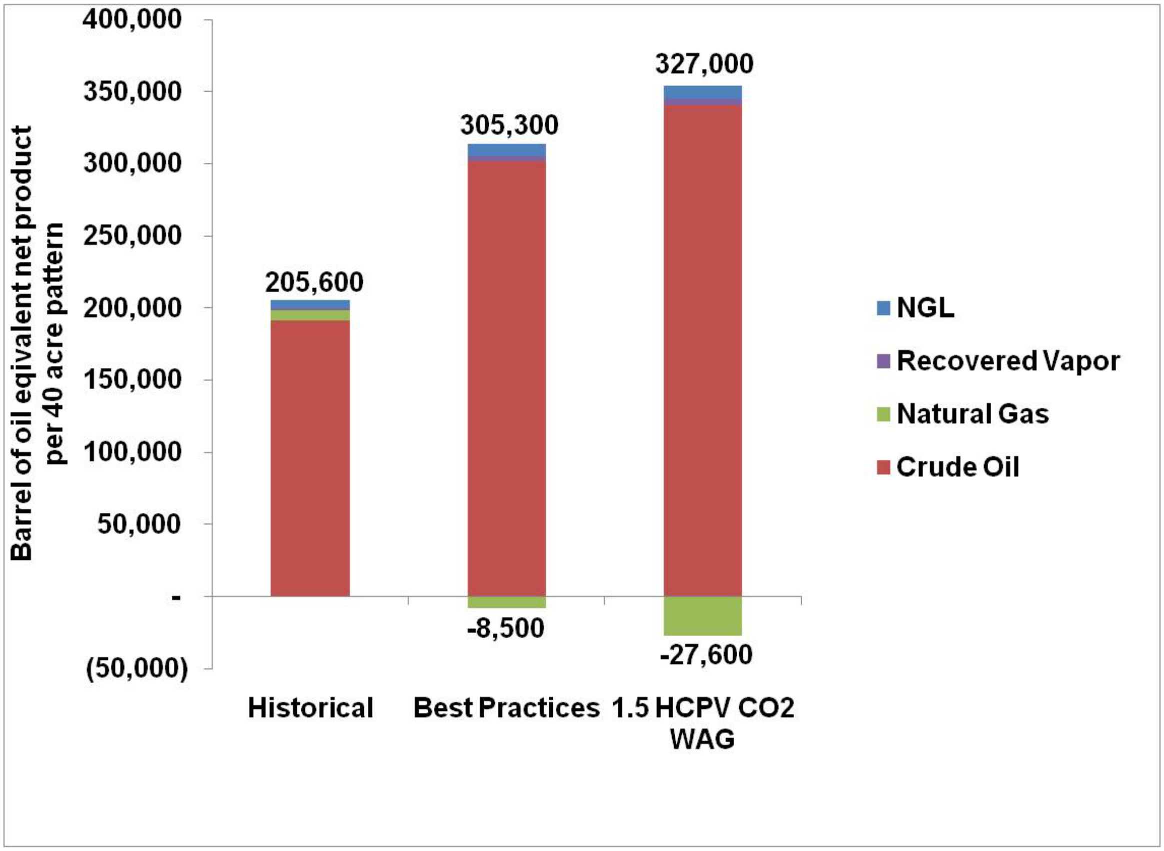

Figure 4-8 Net Hydrocarbon Products Generated per 40-Acre Well Pattern in Each CO_2-EOR Operational Scenario (barrel of oil equivalents per 40 acre pattern). Bars below zero on the ordinate represent natural gas that is purchased to meet energy requirements of CO_2-EOR operations.

These figures show that the primary energy product is indeed crude oil. A significant fraction (approximately 11 percent for all operational scenarios) of gross hydrocarbon product is natural gas (by energy content), but, in best practices and high CO_2 injection scenarios, this produced gas is completely consumed as a feedstock in fluid processing operations and additional natural gas is purchased to meet operational demands. Crude oil and natural gas liquids are not consumed in CO_2-EOR operations.

Complete accounting of all energy inputs into CO_2-EOR operations (not only hydrocarbon fuel use as described above) is provided in Figure 4-9. While natural gas (primarily used in gas-processing plant operations) is the primary energy source, a substantial amount of electricity is used for artificial lift of produced fluid, CO_2 compression, and brine pressurization for WAG injection, and diesel is used in workover rig and well-plugging operations, and to a limited extent in the gas-processing plant (backup electricity generation). Energy requirements for the tank battery are small as compared to those of gas processing.

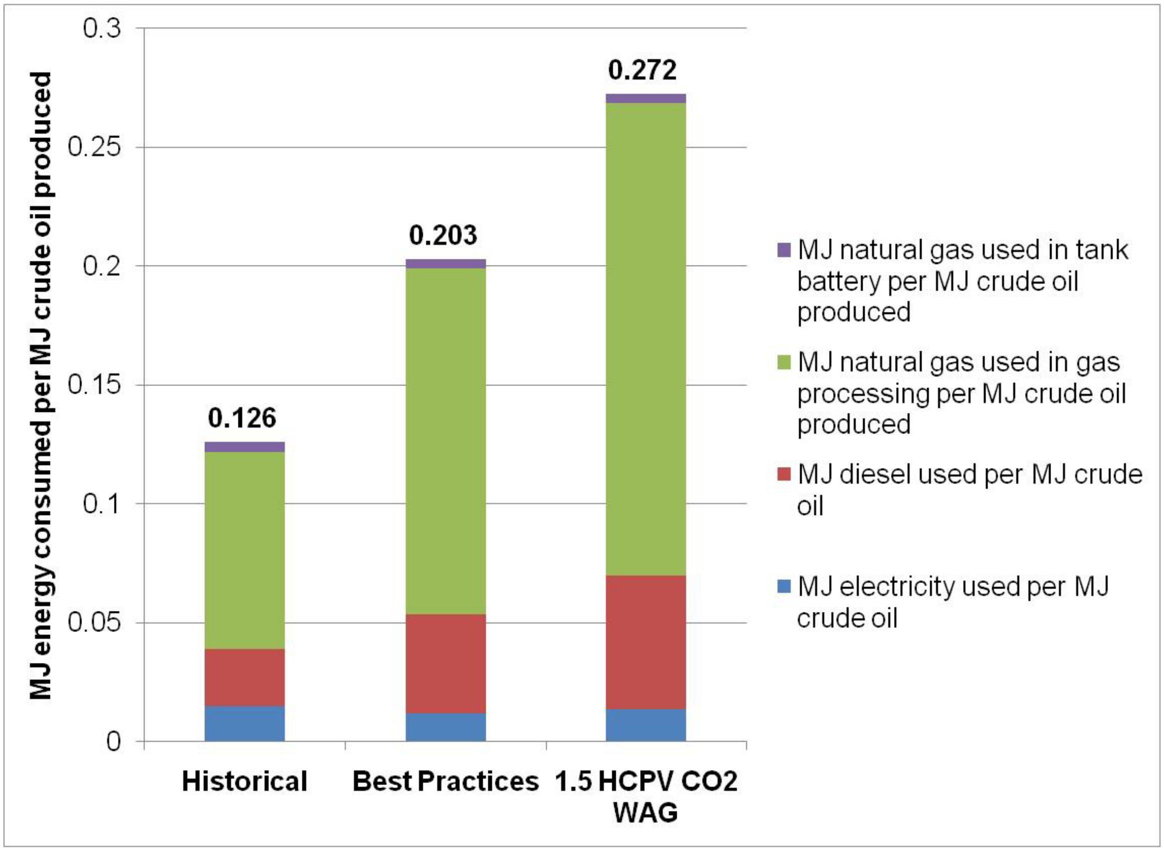

Figure 4-9 Energy Consumed per Unit of Crude Produced for Three CO_2-EOR Operational Scenarios

4.3 Sensitivity Analysis

Uncertainty in appropriateness and quality of data, model structure, and defined scenario used in inventory development affect confidence in the final results. To improve understanding of the potential impact of such uncertainty on the base case emissions estimate, sensitivity of CO_2-EOR gate-to-gate life cycle GHG emissions performance was considered for a select subset of input parameters. The "best practices" CO_2-EOR scenario was selected as a base case, with all of the modeling assumptions detailed in previous sections of this report. Below is a brief description of parameters that were selected for perturbation in the sensitivity analysis. Results of this sensitivity analysis are summarized in Figure 4-10.

4.3.1 Parameters Considered in Sensitivity Analysis

Seven model input parameters were selected to evaluate the sensitivity of CO_2-equivalent emissions per barrel of crude oil. Base case assumptions and sensitivity analysis parameter values and assumptions are summarized in Table 4-4, and discussed in greater detail in subsequent text.

Table 4-4 Selected Parameters Used in Sensitivity Analysis of Gate-to-Gate Life Cycle GHG Emissions Performance of CO_2-flood EOR Operations

	Low Value	Base Case	High Value
GWP Factors	1996 IPCC, 100-year time horizon	2007 IPCC, 100-year time horizon	2007 IPCC, 100 year-time horizon
CO_2-EOR Operational Scenario	Historical	Best Practices	1.5 HCPV CO_2 WAG
Electricity Profile (kg CO_2E)	100% natural gas (0.72)	ERCOT Mix (0.76)	100% coal (1.07)
Tank Battery Vapor Recovery Unit Efficiency (%)	50	95	100
Phase I, II, IV, and V GHG emissions	1 x base case	1 x base case	10 x base case
Displacement Credit for Co-products (NG, NGL)	1.5x base case	1x base case	None
Fugitive Loss (% of CO_2 initially purchased)	0	0	1

4.3.1.1 Global Warming Potential Multiplier

One assumption applied throughout all calculations is that the most recently published 100-year time horizon, the 2007 IPCC global warming potential CO_2 equivalency factors, are most appropriate for estimation of CO_2 -equivalent GHG emissions. These factors, taken from the fourth IPCC Assessment Report (2007) differ slightly from those reported in the Second and Third Assessment Reports (1996 and 2001, respectively) as summarized in Table 4-5. CO_2E emissions per barrel of oil produced under the "best practices" CO_2-EOR scenario was estimated using each set of global warming potential factors. Results show little variance in calculated CO_2 equivalent emissions, with the base case giving the most conservative (highest) result, and 1996 IPCC factors giving the lowest calculated result.

Table 4-5 GHG Constituents Considered Through Sensitivity Analysis Emissions Included in Study Boundary and Their 100-year Time Horizon GWP Factors

Constituent Emitted	Chemical Formula	Global Warming Potential (CO_2-Equivalents)		
		IPCC Second Assessment Report (1996)	IPCC Third Assessment Report (2001)	IPCC Fourth Assessment Report (2007)[a]
Carbon Dioxide	CO_2	1	1	1
Methane	CH_4	21	23	25
Nitrous Oxide	N_2O	310	296	298
Sulfur Hexaflouride	SF_6	23,900	22,200	22,800

[a]Base case for this study

4.3.1.2 CO_2-EOR Scenario

As is detailed throughout this document, three CO_2-EOR scenarios were considered: "historical," "best practices," and "high CO_2 WAG" scenarios. Gate-to-gate life cycle performance (GHG emissions per barrel of oil produced basis) of each of these CO_2-EOR operational scenarios is considered in this sensitivity analysis. Figure 4-10 illustrates that the choice of flood scenario selected to characterize CO_2-EOR flood performance substantially affects the calculated emissions associated with this activity. This sensitivity is a function of a scenario choice as opposed to model or data uncertainty, and the reported variance is considered to be resolved through the identification of "best practices" CO_2-flood EOR as the representative base scenario. It is reported in this context primarily to convey the relative scale of calculated sensitivity to this scenario choice.

4.3.1.3 Electricity Source

In the base case, electricity used in CO_2-EOR operations is characterized as a mix representative of the ERCOT Independent System Operator region using data collected from EPA's eGRID 2007 data (representative of 2005), as described in Appendix B. Sensitivity of gate-to-gate GHG emissions per barrel of oil produced to this parameter was considered by varying the cradle-to-gate GHG emissions above and below this baseline characterization based on characterizations of 100 percent coal-derived electricity and 100 percent natural gas fired electricity, respectively. When 100 percent coal-derived electricity is used, CO_2 equivalent emissions per barrel of crude oil produced increases significantly, while when natural gas-derived electricity is assumed to be used, emissions are slightly lower than in the base case. The resulting range in CO_2 equivalent emissions per barrel of oil produced is believed to be conservatively skewed toward higher emissions, since the likelihood that the ERCOT region would resort to 100 percent coal fired generation is negligible, and the potential emissions benefit of increased application of wind energy in the region is not captured.

4.3.1.4 Vapor Recovery Efficiency

In the base case, it is assumed that vapor is collected from separator vessels, heater/treater vessels, and oil and brine storage tanks at a recovery efficiency of 95 percent. To better understand the impact that this assumption has on the calculated GHG emissions per barrel of crude oil produced, this efficiency factor was varied from 50 percent to 100 percent (with no assumed change in VRU electricity demand). At higher vapor recovery efficiency, less CH_4 is emitted to the atmosphere and additional high BTU hydrocarbon gas is produced (displacing equivalent amount of natural gas, on a higher heating value basis); these two trends serve to decrease overall GHG emissions per barrel below the base case. Decreasing VRU efficiency allows more GHG emissions to the atmosphere and captures less high Btu hydrocarbon gas, as compared to the base case with 95 percent VRU efficiency; these two trends result in significantly higher CO_2 equivalent emissions per barrel of crude oil produced.

4.3.1.5 Phase I, II, IV and V Emissions

Base case characterizations of site evaluation and characterization, site preparation, post EOR site closure, and post-closure MVA include a significant number of modeling choices and assumptions that could result in significant underestimation of the contribution of those (non-operational) phases of activity. To address this concern, the total GHG emissions (kg CO_2E emissions per barrel of oil produced) were increased by an order of magnitude to determine the impact to total emissions from CO_2-EOR activity.

4.3.1.6 Fugitive Loss of Purchased CO_2

In the base case, it is assumed that loss of CO_2 from the flooding activities approaches zero and can be neglected. The influence of this assumption on estimated CO_2 equivalent emissions per barrel of crude oil produced was considered through sensitivity analysis, with the base case of no fugitive loss considered as the low bound input value, and a cumulative fugitive loss of 1 percent (the maximum amount considered to be acceptable to meet the U.S. DOE Sequestration program goal of 99 percent storage permanence) as the high input for sensitivity analysis. Based on this specified loss rate, increased emissions associated with fugitive loss of CO_2 used in CO_2-EOR operations is relatively small as compared to variance as a function of flooding scenario, vapor recovery unit efficiency, or electricity source.

4.3.1.7 Displacement Credit for Natural Gas and Natural Gas Liquid Co-Products

In the gate-to-gate analysis, it is assumed that natural gas and natural gas liquids produced as a coproduct of gas processing operations (and CO_2-EOR activity, more generally) displace natural gas and natural gas liquids, respectively, from the market. As such, a displacement credit is assigned for the CO_2E emissions of an equivalent amount of those products, based on cradle-to-gate profile of those energy products. To consider the sensitivity of the gate-to-gate GHG emissions per barrel of oil to that modeling decision, the displacement credit is varied from zero (no credit given for energy co-products) to 1.5 times the credit assigned based on cradle-to-gate profile of those energy products in the base case.

4.3.2 Discussion of Sensitivity Analysis Results

A Tornado plot shows the results of the sensitivity analysis (Figure 4-10), indicating that choice in CO_2-EOR scenario leads to the largest variance in resulting GHG emissions per barrel of oil produced—a range of variance of 62 percent around the baseline "best practices" result. This variance is reflective of decisions by reservoir engineers and operators on how to run CO_2-EOR operations, in contrast to a bounding analysis of data or model uncertainty. As such, variance resulting from scenario choice should be considered differently than that reported for other parameters. Vapor recovery efficiency is the second largest contributor to variance of the input parameters considered, with a range variance of 13% given the sensitivity range of 50 to 100 percent vapor recovery efficiency. CO_2 equivalent emissions per barrel of oil produced were also sensitive to the source of electricity used in CO_2-EOR operations, with variance of eight percent exhibited by replacing the ERCOT grid mix assumed in the base case with coal- and natural gas-derived electricity (higher and lower upstream GHG emissions, respectively). Assumption of 100 percent coal-derived electricity is considered to be a conservative choice for sensitivity analysis, since it is unlikely that all electricity in the ERCOT region would be provided from higher GHG emitting coal pathways. To consider the potential impact of data deficiencies and limitations in characterization of non-operational activities, the impact of varying all non-operational emissions to a value 10 times as great as the baseline case was considered. This resulted in only a six percent variance in total GHG emissions estimate, emphasizing the observation made previously that operational emissions dominate the life cycle footprint of CO_2-EOR. Potential fugitive loss of purchased CO_2 could also increase CO_2 equivalent emissions of CO_2-EOR activity, but a one percent leakage of purchased CO_2 corresponding with U.S. DOE minimum geologic sequestration storage permanence of 99 percent results in only a 3 percent increase from base case emissions. Displacement credit choice for natural gas and natural gas liquids co-products and choice in 100-year horizon IPCC global warming potential CO_2 equivalent values were found to contribute little to CO_2-EOR activity GHG emissions (three and 0.4 percent, respectively).

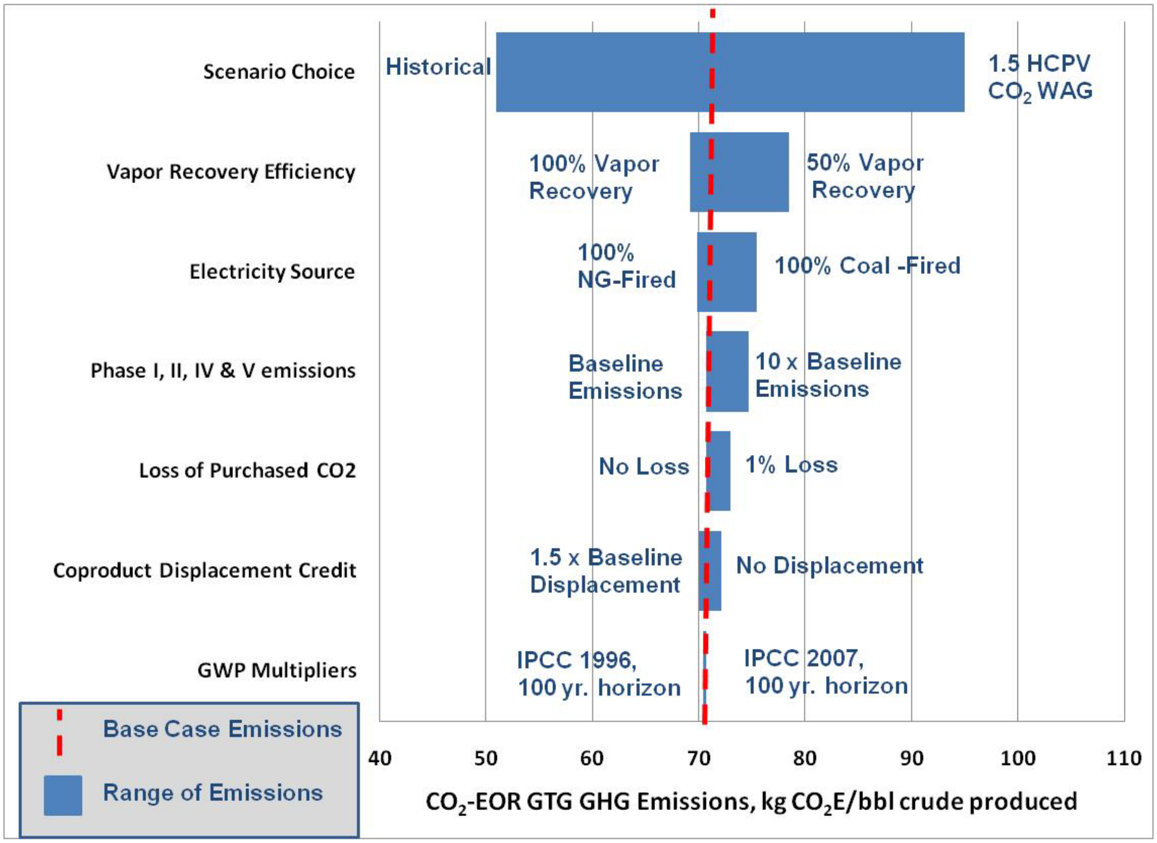

Figure 4-10 Tornado Plot Summarizing Impact of Varying Select Model Input Parameter Values Away from Base Case Assumptions

5.0 Summary of Findings

CO_2-EOR is available technological option to produce incremental oil from reservoirs depleted through primary and water flood secondary oil recovery, while concomitantly geologically storing injected CO_2. Stream-tube models were carried out to estimate flood performance for a set of three CO_2-flood operational scenarios. These model results served as the foundation on which an inventory of ”gate-to-gate” CO_2-EOR activity and analysis of environmental life cycle performance were developed. The assessments considered GHG and criteria air pollutant emissions, water and land use, and energy performance for five phases of CO_2-EOR facility activity: site characterization; site preparation; CO_2-EOR flood operation; well abandonment; and post-closure monitoring, verification, and accounting.

Significant findings of this effort include:

- Stream-tube modeling of low, moderate, and high CO_2 injection volume scenarios revealed that both hydrocarbon production and CO_2 storage increase with increasing volume of CO_2 injection.
- Higher volumes of CO_2 injection correspond to longer flood durations and recycle of larger volumes of total gas that, in the scenarios considered, require energy intensive processing and compression before reinjection.
- The majority of incremental oil production and CO_2 geologic retention is accomplished early in the injection, and longer duration, higher CO_2 volume injection corresponds with lower volume of oil produced and CO_2 sequestered per volume of CO_2 injected.
- Between 22 and 40 percent of injected CO_2 is retained cumulatively over the life of each well pattern. CO_2 that is not retained in one pattern is produced and re-injected in the same or adjacent patterns such that essentially all CO_2 will eventually be geologically stored.
- For every barrel of crude oil extracted through WAG CO_2-EOR, energy feedstocks equivalent to between 13 and 27 percent of the energy content of that oil are consumed.
- Greater than 99 percent of CO_2-EOR energy demand is associated with the operational phase, and gas processing is responsible for between 66 and 73 percent of operational phase energy consumption.
- Greenhouse gas emissions from “gate-to-gate” CO_2-EOR activity are between 51 and 95 kg CO_2e/bbl crude produced for CO_2 injection scenarios considered.
- Gross storage values range between 195 and 228 kg/bbl oil produced.
- Net GHG storage performance (geologic storage minus GHG emissions) range from 116 kg CO_2E/bbl crude oil produced for the highest CO_2 injection scenario, to 157 kg CO_2E/bbl crude oil for the best practices CO_2-EOR scenario.
- Brine production in excess of that which is re-injected through the water-alternating-gas injection ranges from about 1.5 barrels of brine per barrel of oil produced to about 1 barrel of brine per barrel of oil.

Therefore, while oil recovery and CO_2 storage potential may increase on an absolute basis with increasing CO_2 injection, these benefits are weighted heavily to early years of flooding and earlier volumes of CO_2 injection. Longer, higher cumulative volume CO_2 injections effectively dilute benefits over longer periods of injection and erode energy production and CO_2 storage through higher parasitic energy load and increased emissions associated with processing of high volumes of produced gas. Considered together, stream tube model results and related life cycle performance data suggest that, of the three scenarios considered, current "best practices" WAG CO_2-EOR scenario performs best. High-volume CO_2 injection is not favorable from an environmental and energy performance standpoint, but consideration of alternative "next generation" technologies and practices is warranted.

5.1 Next Steps

The work detailed herein develops a framework for detailed process-based characterization of activities associated with CO_2-EOR. The three operational scenarios considered are intended to represent performance of technology as it was performed in its infancy, as it is performed in present application, and as it might be performed in one possible future scenario. This set of scenario choices is by no means exhaustive of alternatives that might reasonably be employed. Furthermore, consideration of gate-to-gate activities associated with CO_2-flood EOR does not provide a complete picture of the technology's environmental performance when integrated into a full LCA. Following is a brief consideration of future work that would help to advance understanding of CO_2-EOR activity and its performance within a larger cradle-to-grave life cycle of CO_2-generating energy systems.

5.1.1 Gate-to-Gate Analysis of Alternative CO_2-EOR Scenarios

There are a number of alternative CO_2-flood EOR scenarios that would be of value to consider to facilitate comparison between current best practices as described herein, and other viable CO_2-EOR schemes. Several conceivable scenarios fall within the general framework of the current CO_2-flood EOR paradigm and would be relatively straightforward to characterize, including considering the following: applying CO_2-EOR technology in reservoirs other than the Permian Basin, using alternative gas-processing technologies, assessing cases with no hydrocarbon gas separation (straight recycle), using large-scale electricity to power CO_2-EOR operations, applying CO_2 re-pressuring ("soak") or CO_2EOR WAG injection before water flood is applied, implementing large-scale infill well placement to enhance tertiary flood oil production, and considering short CO_2 injection periods to maximize CO_2 storage per unit energy input as opposed to maximizing oil production.

There are also scenarios that would require more-aggressive modification or reworking of the model described in this report.. These scenarios would characterize schemes that serve as transitions between straight "business-as-usual" CO_2-flood EOR activity and dedicated brine sequestration, such as is being considered in flooding residual oil zones and/or deep brine aquifers. These alternative CO_2-EOR technologies include:

- CO_2-flood stimulation of residual oil zones - naturally water-flooded residual resources that are believed to underlie primary oil production zones in extensive "freeway" aquifers. These

- Stacked storage of CO_2 – a scenario that allows for CO_2-flood EOR with storage in dedicated storage in adjacent or underlying brine aquifers. This technology alternative has the potential to address issues of intermittency in CO_2 demand associated with traditional CO_2-EOR operations.
- Consideration of the application of directional drilling technology to stimulate additional oil production

5.1.2 Cradle-to-Grave Life Cycle Analyses

Gate-to-gate characterization of CO_2-EOR described in this work will be incorporated with life cycle inventories of other primary activities to develop full cradle-to-grave life cycle analyses of energy production pathways of interest. For example, cradle-to-grave analyses of electricity production and liquid fuel production recently published by NETL include scenarios with carbon capture and sequestration. These studies employ simplified characterizations of dedicated brine sequestration as the CO_2 sequestration technology. Additional scenarios could be considered in which these energy product pathways incorporate CO_2-flood EOR in place of brine sequestration as a sink for captured CO_2. In addition, there may be interest in coupling CO_2-EOR not with anthropogenic CO_2, but rather with CO_2 from natural sources—the primary source of CO_2 used today for CO_2-flood EOR. These natural geologic CO_2 sources could also be considered as intermediate storage locations for anthropogenic CO_2 to buffer intermittency of supply and demand in anthropogenic CO_2 capture/geologic sequestration scenarios. It should be noted that incorporating CO_2-EOR gate-to-gate activity into larger cradle-to-grave pathways will create a source of uncertainty associated with methods of allocation. Fortunately, there exists a substantial body of literature considering this topic in some detail.

5.1.3 Other Life Cycle Assessment Considerations

The present study is limited to considering only the environmental performance of CO_2-EOR activity, including GHG emissions, criteria pollutant emissions, water use, land use, and energy performance. In addition to consideration of these process parameters, it would also be of value to integrate life cycle cost analysis of CO_2-EOR. Also, the life cycle performance of CO_2-EOR has been characterized based on single point data for a number of parameters that would be better characterized stochastically. Future work might consider establishing probability distributions of key model parameters for application in uncertainty analysis of the life cycle model. Such an effort would be facilitated by collaborative involvement and peer review by individuals and institutions with expertise in the oil and gas industry and other related fields.

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Appendix A: CO_2 Prophet CO_2-EOR Screening Model Definition of Relative Permeability Parameters

Relative Permeability of Water

$$Krw = Kwro\left(\frac{Sw - Swir}{1 - Swir - Sorw}\right)^{Expw}$$

where:

Krw is the relative permeability of water
Sw is the water saturation
Expw is the water equation exponent The default is 2.0
Swir is the irreducible water saturation. The default is 0.2 which is also the same as Swc
Sorw is the residual oil to waterflood. The default is 0.37.
Kwro is the endpoint (maximum) relative permeability of water at the residual oil saturation. The default is 0.30.

Relative Permeability of Oil

$$Krow = Krocw\left(\frac{1 - Sw - Sorw}{1 - Swc - Sorw}\right)^{Expow}$$

where:

Krow is the relative permeability of oil
Sw is the water saturation
Expow is the oil equation exponent. The default is 2.0.
Swc is the connate water saturation. The default is 0.2.
Sorw is the residual oil to waterflood. The default is 0.37.
Krocw is the endpoint (maximum) relative permeability of oil at the irreducible water saturation. The default is 0.40.

Relative Permeability of Gas

$$Krg = Krgcw\left(\frac{Sg - Sgr}{1 - Swc - Sgr}\right)^{Expg}$$

where:

Krg is the relative permeability of gas
Sg is the gas saturation
Expg is the gas equation exponent. The default is 2.0.
Swc is the connate water saturation. The default is 0.2
Sgr is the residual gas saturation to an oilflood. The default is 0.37 which is the value for Sorw
Krgcw is the endpoint (maximum) relative permeability of gas at the connate water saturation. The default is 0.40.

Relative Permeability of Oil

$$Krog = Krocw\left(\frac{1 - Swc - Sorg - Sg}{1 - Swc - Sorg}\right)^{Expog}$$

where:

Krog is the relative permeability of oil
Sg is the gas saturation
Expog is the oil equation exponent. The default is 2.0.
Swc is the connate water saturation. The default is 2.0.
Sorg is the residual oil to a gas flood. The default is 0.37 which is also the value for Sorw
Krocw is the endpoint (maximum) relative permeability of oil at irreducible water saturation. The default is 0.4.

Relative Permeability of Solvent (CO_2)

$$\mathrm{Krs} = \mathrm{Krsmax}\left(\frac{Sg - Ssr}{1 - Swir - Ssr - Sorm}\right)^{Exps}$$

where:

Krs is the relative permeability of solvent
Sg is the gas (i.e., solvent) saturation
Exps is the solvent equation exponent. The default value is Expg which is 2.0.
Swir is the irreducible water saturation. The default is Swc which is 0.2.
Ssr is the residual gas (i.e., solvent) saturation. The default value is Sgr which is 0.37.
Sorm is the residual oil saturation to solvent. The default value is 0.001.
Krsmax is the endpoint (maximum) relative permeability of solvent at the irreducible water saturation. The default value is Krogcw which is 0.4.

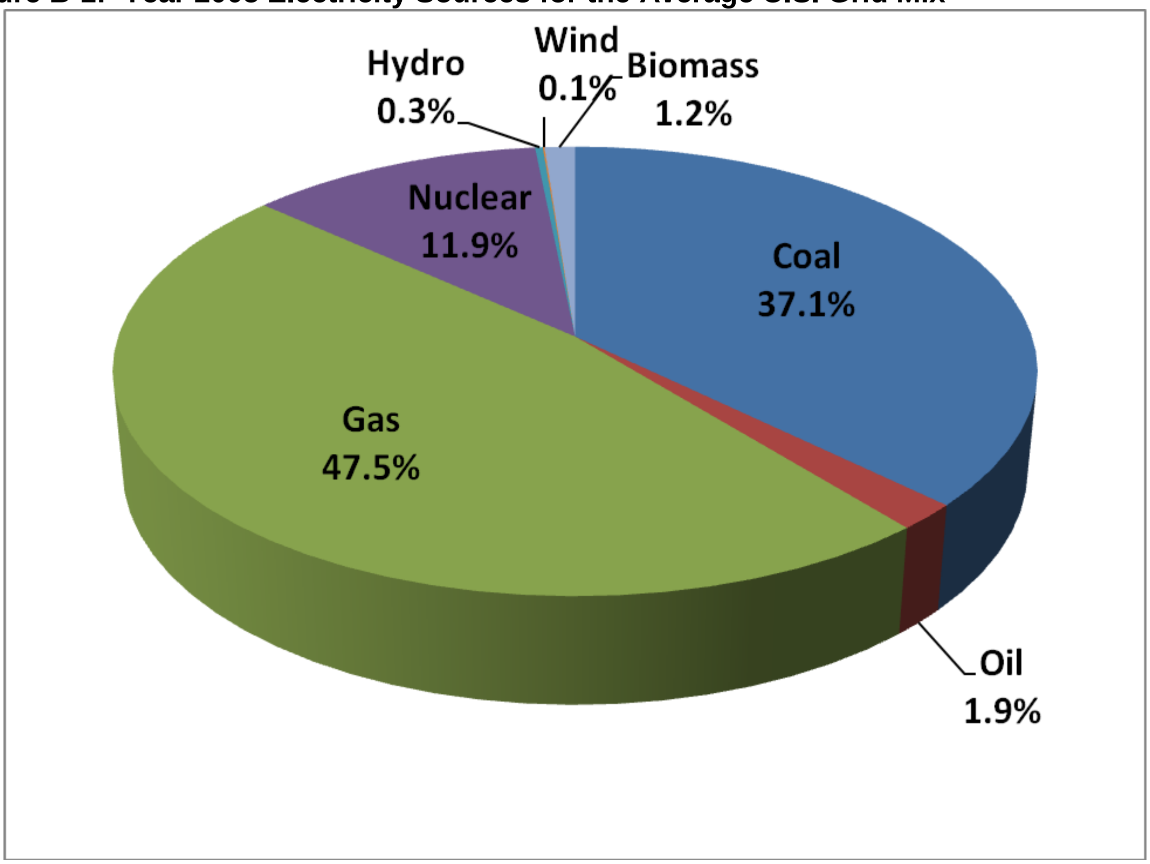
Table A-1: CO_2 Prophet model parameters and default values used in CO_2 Prophet model to characterize relative permeability of fluids that interact in a CO_2-EOR miscible flood. These values are used in all CO_2-EOR scenarios developed herein.

Parameter Description	CO_2 Prophet Variable	CO_2 Prophet Default	Units
Residual oil saturation to water	SORW	0.32	fraction (0-1)
Residual oil saturation to gas	SORG	0.32	fraction (0-1)
Residual oil saturation to miscible gas solvent flood	SORM	0.05	fraction (0-1)
Residual gas saturation	SGR	0.32	fraction (0-1)
Residual solvent (CO_2) saturation	SSR	0.32	fraction (0-1)
Connate water saturation	SWC	0.2	fraction (0-1)
Irreducible water saturation as water saturation is decreasing	SWIR	0.2	fraction (0-1)
Relative permeability of oil at connate water saturation	KROCW	0.4	fraction (0-1)
Relative permeability of water at residual oil - no gas saturation	KWRO	0.3	fraction (0-1)
End point relative permeability of solvent at a solvent saturation of 1 - SWIR - SORM	KRSMAX	0.4	fraction (0-1)
Relative permeability of Gas at connate water saturation	KRGCW	0.4	fraction (0-1)
Exponent for oil curve from water-oil relative permeabilities	EXPOW	2	unitless
Exponent for water curve from water-oil relative permeabilities	EXPW	2	unitless
Exponent for solvent from relative permeability curve	EXPS	2	unitless
Exponent for gas curve from gas-oil relative permeability	EXPG	2	unitless
Exponent for oil curve from gas-oil relative permeabilities	EXPOG	2	unitless
Options for miscible oleic phase permeability	KRMSEL	2	-
Degree of mixing parameter - ranges from 0.0 to 1.0	W	0.666	fraction (0-1)

Appendix B: Cradle-to-Gate GHG Emissions Inventory for Electric Power from the ERCOT ISO Region Grid Mix

Certain emissions from electricity generating facilities are tracked by EPA (EPA 2007a) and are publically available in the Emissions & Generation Resource Integrated Database (eGRID). While this database includes comprehensive coverage of CO_2 emissions from these generating facilities, it does not address other GHG constituents such as N_2O and CH_4 in its inventory.[8] The emissions data within e-GRID only includes that attributable to operations and does not represent construction or upstream emissions. Therefore, GaBi 4 modeling data were modified to generate a profile more inclusive of upstream and construction emissions not represented within eGRID. An ERCOT ISO region grid mix was generated where the individual electricity source profiles (solar, wind, hydro, etc.) were aggregated into a mix consistent with the 2005 U.S. electricity source mix. In this mix, a small fraction of electricity generated from "other fossil" feedstock is assumed to be adequately represented by an oil-fired generation pathway. Figure B-1 shows the source mix as a percentage of total U.S. electricity generation.

Figure B-1: Year 2005 Electricity Sources for the Average U.S. Grid Mix



The cradle-to-gate GHG emissions profile estimated using this assumed electricity grid mix in the ERCOT ISO region is reported in Table B-1.

Table B-1. Estimated cradle-to-gate electricity grid mix emissions from 2005 Electric Reliability Council of Texas Independent System Operator.

Pollutant	Output Emission Rates	Units
CO_2	0.736	kg/MWh
SO_2	2.84×10^{-3}	kg/MWh
NO_x	1.26×10^{-3}	kg/MWh
Dust (unspecified)	5.34×10^{-5}	kg/MWh
Non-Methane VOCs	1.02×10^{-4}	kg/MWh
Lead (II)	2.54×10^{-8}	kg/MWh
CH_4	9.76×10^{-4}	kg/MWh
N_2O	9.46×10^{-6}	kg/MWh
SF6	8.95×10^{-13}	kg/MWh

Appendix C: Raw Output from CO_2 Prophet Model for Historical, Best Practices, and 1.5 HCPV CO_2 WAG CO_2-EOR Scenarios.

Historical CO_2-EOR Scenario

```
"Historical" Tapered WAG, 0.4 HCPV Permian



                 ************** RESERVOIR  DATA **************

           PRESSURE                                          PATTERN
  TEMP     OPERATING    MMP         POROSITY  THICKNESS   AREA
   F         PSIA      PSIA         FRACTION     FEET     ACRES
  123.0      2368.0    1523.0        0.1100      76.0     40.00

                                    INITITAL HC
   FLOOD START SATURATIONS          PORE VOLUME     DYKSTRA-
    OIL        WATER       GAS      HCPV - OOIP     PARSONS    HORIZONTAL
  SOINIT      SWINIT     SGINIT        MMRB         FACTOR       LAYERS
 0.3200      0.6800     0.0000        2.0755        0.7300         5


                *************** FLUID DATA ***************

   STOCK     SOLUTION   SPECIFIC       FORMATION VOLUME FACTOR
  TANK OIL     GOR       GRAVITY     OIL        WATER      SOLVENT
   GRAVITY     (Rs)        SG        Bo          Bw         Bco2
     API      ft3/STB   (Air=1.0)   RB/STB     RB/STB     RB/MMSCF
    36.0       805.0     0.6500     1.2000     1.0119     459.557

  FLUID DENSITIES AT RES T&P        FLUID VISCOSITIES  AT RES T&P     WATER
  RES OIL     WATER     SOLVENT      OIL        WATER      SOLVENT    SALINITY
  GMS/CC      GMS/CC    GMS/CC        cp          cp          cp         ppm
  0.7980      1.0550    0.7248      1.760       0.720      0.068      96000.


            ********** RELATIVE PERMEABILITY PARAMETERS **********

   WTR FLD   GAS FLD     MISC FLD
    SORW      SORG        SORM
  0.3200    0.3200      0.0500

    SGR       SSR                    SWC        SWIR
  0.3200    0.3200                 0.2000      0.2000


   KROCW     KWRO        KRSMAX     KRGCW
  0.4000    0.3000      0.4000     0.4000
```

EXPOW	EXPW	EXPS	EXPG	EXPOG
2.000	2.000	2.000	2.000	2.000

MIX PARAMETER OMEGA	MISCIBLE RELATIVE PERMEABILITY
0.6660	EQUAL TO Krow

*********** INJECTION/PRODUCTION PARAMETERS *********

INJECTION SEQUENCES	WAG EXPRESSED AS TIME OR VOL	PATTERN TYPE	INJECTION WELLS	OUTPUT TIME STEPS YEARS
4	V	5S	1	1.000

				AVGE (TOTAL WELLS) INJECTION FLUID		
CUM. INJECT HCPV	INCRE TIME YEARS	CUM. TIME YEARS	SEQUENCE RATE RB/D	FRACTIONAL WATER	CONTENT SOLVENT	WAG WTR:GAS
0.2000	1.994	1.994	569.86	0.0000	1.0000	.0000E+00
0.4000	1.996	3.991	569.28	0.5000	0.5000	.1000E+01
0.7000	2.996	6.986	569.08	0.6667	0.3333	.2000E+01
1.7000	9.992	16.979	568.70	1.0000	0.0000	.1000E+07

		AVGE RATE FOR PATTERN			TOTAL PATTERN SURFACE RATES	
		****** SEQUENTIAL ******				
INCRE TIME YEARS	CUM. TIME YEARS	RB/D	HCPV/D	HCPV/YR	WATER STB/D	SOLVENT MMSCF/D
1.994	1.994	569.86	0.27456E-03	0.10028	0.0	1.24
1.996	3.991	569.28	0.27428E-03	0.10018	562.0	1.24
2.996	6.986	569.08	0.27418E-03	0.10015	562.0	1.24
9.992	16.979	568.70	0.27400E-03	0.10008	562.0	0.00

**** INJECTION **** INJECTION **** INJECTION **** INJECTION **** INJECTION

SUMMARY OF FLUID INJECTION
CUMULATIVE DATA

TIME	***** HCPV INPUT *****			WATER	SOLVENT
YRS	TOTAL	WATER	SOLVENT	MSTB	MMSCF
0.000	0.0000	0.0000	0.0000	0.0	0.0
1.000	0.1003	0.0000	0.1003	0.0	452.9
1.994	0.2000	0.0000	0.2000	0.0	903.3
2.000	0.2006	0.0003	0.2003	0.6	904.6

3.000	0.3007	0.0504	0.2504	103.3	1130.8
3.991	0.4000	0.1000	0.3000	205.1	1354.9
4.000	0.4009	0.1006	0.3003	206.4	1356.3
5.000	0.5011	0.1674	0.3337	343.3	1507.1
6.000	0.6012	0.2341	0.3671	480.3	1657.8
6.986	0.7000	0.3000	0.4000	615.3	1806.6
7.000	0.7014	0.3014	0.4000	618.1	1806.6
8.000	0.8014	0.4014	0.4000	823.4	1806.6
9.000	0.9015	0.5015	0.4000	1028.7	1806.6
10.000	1.0016	0.6016	0.4000	1234.0	1806.6
11.000	1.1017	0.7017	0.4000	1439.2	1806.6
12.000	1.2017	0.8017	0.4000	1644.5	1806.6
13.000	1.3018	0.9018	0.4000	1849.8	1806.6
14.000	1.4019	1.0019	0.4000	2055.1	1806.6
15.000	1.5020	1.1020	0.4000	2260.3	1806.6
16.000	1.6021	1.2021	0.4000	2465.6	1806.6
16.979	1.7000	1.3000	0.4000	2666.5	1806.6

*** PRODUCTION ***** PRODUCTION ***** PRODUCTION ***** PRODUCTION ***

SUMMARY OF FLUID PRODUCTION
CUMULATIVE DATA

	********** HCPV OUTPUT **********				OIL	RECOVERY	
TIME	HYDROCARBON PORE VOLUMES OUTPUT				RECOVERY	% OF INJECTANT	
YRS	TOTAL	OIL	WATER	SOLVENT	%OOIP	WATER	SOLVENT
0.000	0.0000	0.0000	0.0000	0.0000	0.00	0.00	0.00
1.000	0.1003	0.0000	0.1002	0.0000	0.00	0.00	0.05
1.994	0.2000	0.0147	0.1579	0.0274	1.47	0.00	13.71
2.000	0.2006	0.0148	0.1581	0.0277	1.48	******	13.83
3.000	0.3007	0.0299	0.1989	0.0719	2.99	394.91	28.73
3.991	0.4000	0.0440	0.2450	0.1110	4.40	244.99	37.01
4.000	0.4009	0.0441	0.2455	0.1113	4.41	243.96	37.07
5.000	0.5011	0.0564	0.3016	0.1431	5.64	180.17	42.89
6.000	0.6012	0.0661	0.3668	0.1682	6.61	156.67	45.84
6.986	0.7000	0.0752	0.4317	0.1930	7.52	143.91	48.26
7.000	0.7014	0.0754	0.4326	0.1934	7.54	143.55	48.35
8.000	0.8014	0.0839	0.5037	0.2138	8.39	125.47	53.46
9.000	0.9015	0.0898	0.5898	0.2219	8.98	117.60	55.48
10.000	1.0016	0.0943	0.6803	0.2269	9.43	113.09	56.73
11.000	1.1017	0.0979	0.7733	0.2304	9.79	110.22	57.61
12.000	1.2017	0.1008	0.8679	0.2330	10.08	108.25	58.25
13.000	1.3018	0.1035	0.9631	0.2352	10.35	106.79	58.81
14.000	1.4019	0.1058	1.0592	0.2369	10.58	105.72	59.22
15.000	1.5020	0.1077	1.1560	0.2383	10.77	104.90	59.57
16.000	1.6021	0.1093	1.2534	0.2393	10.93	104.27	59.83
16.979	1.7000	0.1106	1.3492	0.2402	11.06	103.78	60.05

CUMULATIVE

	ER OIL	OIL	WATER	HC GAS	SOLVENT	GOR	WOR
YRS	%OOIP	MSTB	MSTB	MMSCF	MMSCF	MSCF/STB	STB/STB
0.000	0.00	0.0	0.0	0.0	0.0	0.000E+00	0.000E+00
1.000	0.00	0.1	205.5	0.1	0.2	0.383E+01	0.287E+04
1.994	1.47	25.4	323.9	20.4	123.9	0.569E+01	0.128E+02
2.000	1.48	25.6	324.3	20.6	125.1	0.570E+01	0.127E+02
3.000	2.99	51.7	408.0	41.6	324.9	0.709E+01	0.790E+01
3.991	4.40	76.1	502.5	61.3	501.4	0.739E+01	0.660E+01
4.000	4.41	76.3	503.5	61.4	502.8	0.739E+01	0.660E+01
5.000	5.64	97.5	618.6	78.5	646.4	0.744E+01	0.634E+01
6.000	6.61	114.4	752.5	92.1	759.9	0.745E+01	0.658E+01
6.986	7.52	130.1	885.5	104.8	871.8	0.750E+01	0.680E+01
7.000	7.54	130.4	887.3	104.9	873.5	0.751E+01	0.681E+01
8.000	8.39	145.2	1033.1	116.8	965.8	0.746E+01	0.712E+01
9.000	8.98	155.3	1209.8	125.0	1002.3	0.726E+01	0.779E+01
10.000	9.43	163.1	1395.5	131.3	1024.9	0.709E+01	0.855E+01
11.000	9.79	169.3	1586.3	136.3	1040.7	0.695E+01	0.937E+01
12.000	10.08	174.4	1780.2	140.4	1052.4	0.684E+01	0.102E+02
13.000	10.35	179.1	1975.4	144.2	1062.4	0.674E+01	0.110E+02
14.000	10.58	183.0	2172.6	147.3	1069.9	0.665E+01	0.119E+02
15.000	10.77	186.3	2371.1	150.0	1076.1	0.658E+01	0.127E+02
16.000	10.93	189.1	2571.0	152.2	1080.9	0.652E+01	0.136E+02
16.979	11.06	191.4	2767.3	154.0	1084.9	0.647E+01	0.145E+02

****

SUMMARY OF FLUID PRODUCTION
INCREMENTAL DATA

	********** HCPV OUTPUT **********				OIL
TIME	HYDROCARBON PORE VOLUMES OUTPUT				RECOVERY
YRS	TOTAL	OIL	WATER	SOLVENT	%OOIP
0.000	0.0000	0.0000	0.0000	0.0000	0.00
1.000	0.1003	0.0000	0.1002	0.0000	0.00
1.994	0.0997	0.0146	0.0577	0.0274	1.46
2.000	0.0006	0.0001	0.0002	0.0003	0.01
3.000	0.1002	0.0151	0.0408	0.0442	1.51
3.991	0.0993	0.0141	0.0461	0.0391	1.41
4.000	0.0009	0.0001	0.0005	0.0003	0.01
5.000	0.1001	0.0122	0.0561	0.0318	1.22
6.000	0.1001	0.0098	0.0653	0.0251	0.98
6.986	0.0988	0.0091	0.0649	0.0248	0.91
7.000	0.0014	0.0001	0.0009	0.0004	0.01
8.000	0.1001	0.0086	0.0711	0.0204	0.86
9.000	0.1001	0.0059	0.0861	0.0081	0.59
10.000	0.1001	0.0045	0.0905	0.0050	0.45
11.000	0.1001	0.0036	0.0930	0.0035	0.36
12.000	0.1001	0.0029	0.0946	0.0026	0.29
13.000	0.1001	0.0027	0.0952	0.0022	0.27
14.000	0.1001	0.0022	0.0962	0.0017	0.22
15.000	0.1001	0.0019	0.0968	0.0014	0.19
16.000	0.1001	0.0016	0.0974	0.0011	0.16

16.979	0.0979	0.0013	0.0957	0.0009	0.13

YRS	ER OIL %OOIP	OIL MSTB	WATER MSTB	HC GAS MMSCF	SOLVENT MMSCF	INCREMENTAL GOR MSCF/STB	WOR STB/STB
0.000	0.00	0.0	0.0	0.0	0.0	0.000E+00	0.000E+00
1.000	0.00	0.1	205.5	0.1	0.2	0.383E+01	0.287E+04
1.994	1.46	25.3	118.4	20.4	123.7	0.569E+01	0.468E+01
2.000	0.01	0.2	0.4	0.1	1.2	0.757E+01	0.205E+01
3.000	1.51	26.1	83.8	21.0	199.8	0.846E+01	0.321E+01
3.991	1.41	24.4	94.5	19.7	176.5	0.803E+01	0.387E+01
4.000	0.01	0.2	1.0	0.2	1.4	0.744E+01	0.450E+01
5.000	1.22	21.2	115.1	17.1	143.6	0.758E+01	0.543E+01
6.000	0.98	16.9	133.9	13.6	113.4	0.753E+01	0.794E+01
6.986	0.91	15.8	133.1	12.7	112.0	0.790E+01	0.843E+01
7.000	0.01	0.2	1.8	0.2	1.7	0.861E+01	0.846E+01
8.000	0.86	14.8	145.8	11.9	92.3	0.704E+01	0.985E+01
9.000	0.59	10.2	176.6	8.2	36.5	0.440E+01	0.174E+02
10.000	0.45	7.8	185.7	6.3	22.6	0.370E+01	0.237E+02
11.000	0.36	6.2	190.8	5.0	15.7	0.335E+01	0.309E+02
12.000	0.29	5.1	193.9	4.1	11.7	0.311E+01	0.382E+02
13.000	0.27	4.7	195.2	3.8	10.0	0.293E+01	0.416E+02
14.000	0.22	3.9	197.3	3.1	7.6	0.276E+01	0.510E+02
15.000	0.19	3.3	198.5	2.7	6.2	0.265E+01	0.594E+02
16.000	0.16	2.8	199.8	2.2	4.8	0.257E+01	0.726E+02
16.979	0.13	2.3	196.4	1.9	3.9	0.252E+01	0.851E+02

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            "State-of-art" Tapered WAG, 1.0 HCPV Permian mean re

             ************** RESERVOIR  DATA **************

            PRESSURE                                   PATTERN
  TEMP     OPERATING    MMP        POROSITY  THICKNESS  AREA
   F          PSIA      PSIA       FRACTION     FEET     ACRES
  123.0      2368.0   1523.0        0.1100      76.0     40.00

                                   INITITAL HC
   FLOOD START SATURATIONS         PORE VOLUME     DYKSTRA-
    OIL        WATER       GAS     HCPV - OOIP     PARSONS    HORIZONTAL
  SOINIT      SWINIT     SGINIT       MMRB         FACTOR       LAYERS
 0.3200     0.6800     0.0000       2.0755       0.7300         5


            *************** FLUID DATA ***************

    STOCK    SOLUTION  SPECIFIC        FORMATION VOLUME FACTOR
  TANK OIL     GOR     GRAVITY       OIL        WATER      SOLVENT
   GRAVITY     (Rs)       SG          Bo         Bw         Bco2
     API      ft3/STB  (Air=1.0)    RB/STB     RB/STB     RB/MMSCF
    36.0       805.0    0.6500      1.2000     1.0119     459.557

  FLUID DENSITIES AT RES T&P       FLUID VISCOSITIES  AT RES T&P     WATER
  RES OIL     WATER     SOLVENT      OIL        WATER      SOLVENT   SALINITY
  GMS/CC     GMS/CC     GMS/CC        cp          cp          cp        ppm
  0.7980     1.0550     0.7248      1.760      0.720       0.068     96000.


          ********** RELATIVE PERMEABILITY PARAMETERS **********

   WTR FLD   GAS FLD     MISC FLD
    SORW      SORG         SORM
  0.3200    0.3200       0.0500

    SGR       SSR                       SWC        SWIR
  0.3200    0.3200                    0.2000     0.2000


   KROCW     KWRO         KRSMAX      KRGCW
  0.4000    0.3000       0.4000     0.4000

   EXPOW     EXPW          EXPS        EXPG       EXPOG
  2.000     2.000        2.000      2.000      2.000


  MIX PARAMETER
    OMEGA         MISCIBLE RELATIVE PERMEABILITY
   0.6660         EQUAL TO Krow
```

*********** INJECTION/PRODUCTION PARAMETERS *********

INJECTION SEQUENCES	WAG EXPRESSED AS TIME OR VOL	PATTERN TYPE	INJECTION WELLS	OUTPUT TIME STEPS YEARS
4	V	5S	1	1.000

CUM. INJECT HCPV	INCRE TIME YEARS	CUM. TIME YEARS	SEQUENCE RATE RB/D	AVGE (TOTAL WELLS) INJECTION FLUID FRACTIONAL WATER	CONTENT SOLVENT	WAG WTR:GAS
0.2500	2.493	2.493	569.86	0.0000	1.0000	.0000E+00
0.7500	4.991	7.484	569.28	0.5000	0.5000	.1000E+01
1.5000	7.489	14.973	569.08	0.6667	0.3333	.2000E+01
2.5000	9.987	24.960	568.99	0.7500	0.2500	.3000E+01

INCRE TIME YEARS	CUM. TIME YEARS	AVGE RATE FOR PATTERN ****** SEQUENTIAL ****** RB/D	HCPV/D	HCPV/YR	TOTAL PATTERN SURFACE RATES WATER STB/D	SOLVENT MMSCF/D
2.493	2.493	569.86	0.27456E-03	0.10028	0.0	1.24
4.991	7.484	569.28	0.27428E-03	0.10018	562.0	1.24
7.489	14.973	569.08	0.27418E-03	0.10015	562.0	1.24
9.987	24.960	568.99	0.27414E-03	0.10013	562.0	1.24

**** INJECTION **** INJECTION **** INJECTION **** INJECTION ****
INJECTION

SUMMARY OF FLUID INJECTION
CUMULATIVE DATA

TIME YRS	***** HCPV INPUT ***** TOTAL	WATER	SOLVENT	WATER MSTB	SOLVENT MMSCF
0.000	0.0000	0.0000	0.0000	0.0	0.0
1.000	0.1003	0.0000	0.1003	0.0	452.9
2.000	0.2006	0.0000	0.2006	0.0	905.8
2.493	0.2500	0.0000	0.2500	0.0	1129.1
3.000	0.3008	0.0254	0.2754	52.1	1243.8
4.000	0.4010	0.0755	0.3255	154.8	1470.0
5.000	0.5012	0.1256	0.3756	257.6	1696.3
6.000	0.6013	0.1757	0.4257	360.3	1922.5
7.000	0.7015	0.2258	0.4758	463.1	2148.7
7.484	0.7500	0.2500	0.5000	512.8	2258.2
8.000	0.8017	0.2845	0.5172	583.5	2336.0
9.000	0.9018	0.3512	0.5506	720.4	2486.8

10.000	1.0020	0.4180	0.5840	857.3	2637.5
11.000	1.1021	0.4847	0.6174	994.3	2788.3
12.000	1.2023	0.5515	0.6508	1131.2	2939.1
13.000	1.3024	0.6183	0.6841	1268.2	3089.8
14.000	1.4026	0.6850	0.7175	1405.1	3240.6
14.973	1.5000	0.7500	0.7500	1538.4	3387.3
15.000	1.5027	0.7520	0.7507	1542.5	3390.4
16.000	1.6028	0.8271	0.7757	1696.6	3503.4
17.000	1.7030	0.9022	0.8007	1850.6	3616.5
18.000	1.8031	0.9773	0.8258	2004.6	3729.5
19.000	1.9032	1.0524	0.8508	2158.7	3842.6
20.000	2.0033	1.1275	0.8758	2312.7	3955.6
21.000	2.1035	1.2026	0.9009	2466.7	4068.7
22.000	2.2036	1.2777	0.9259	2620.8	4181.7
23.000	2.3037	1.3528	0.9509	2774.8	4294.8
24.000	2.4039	1.4279	0.9760	2928.8	4407.9
24.960	2.5000	1.5000	1.0000	3076.7	4516.4

*** PRODUCTION ***** PRODUCTION ***** PRODUCTION ***** PRODUCTION ***

SUMMARY OF FLUID PRODUCTION
CUMULATIVE DATA

	********** HCPV OUTPUT **********				OIL	RECOVERY	
TIME	HYDROCARBON PORE VOLUMES OUTPUT				RECOVERY	% OF INJECTANT	
YRS	TOTAL	OIL	WATER	SOLVENT	%OOIP	WATER	SOLVENT
0.000	0.0000	0.0000	0.0000	0.0000	0.00	0.00	0.00
1.000	0.1003	0.0000	0.1002	0.0000	0.00	0.00	0.05
2.000	0.2006	0.0148	0.1581	0.0277	1.48	0.00	13.81
2.493	0.2500	0.0231	0.1725	0.0544	2.31	0.00	21.76
3.000	0.3008	0.0298	0.1894	0.0816	2.98	745.85	29.62
4.000	0.4010	0.0435	0.2275	0.1300	4.35	301.41	39.93
5.000	0.5012	0.0559	0.2768	0.1685	5.59	220.40	44.86
6.000	0.6013	0.0668	0.3298	0.2047	6.68	187.74	48.09
7.000	0.7015	0.0773	0.3829	0.2414	7.73	169.60	50.73
7.484	0.7500	0.0823	0.4077	0.2600	8.23	163.08	51.99
8.000	0.8017	0.0878	0.4339	0.2801	8.78	152.52	54.15
9.000	0.9018	0.0969	0.4939	0.3110	9.69	140.64	56.48
10.000	1.0020	0.1047	0.5582	0.3391	10.47	133.55	58.06
11.000	1.1021	0.1117	0.6239	0.3666	11.17	128.70	59.38
12.000	1.2023	0.1179	0.6901	0.3942	11.79	125.13	60.57
13.000	1.3024	0.1242	0.7558	0.4224	12.42	122.25	61.74
14.000	1.4026	0.1301	0.8219	0.4506	13.01	119.98	62.80
14.973	1.5000	0.1355	0.8862	0.4782	13.55	118.16	63.77
15.000	1.5027	0.1357	0.8880	0.4790	13.57	118.08	63.81
16.000	1.6028	0.1410	0.9565	0.5054	14.10	115.64	65.15
17.000	1.7030	0.1458	1.0289	0.5283	14.58	114.04	65.97
18.000	1.8031	0.1503	1.1021	0.5507	15.03	112.77	66.69
19.000	1.9032	0.1544	1.1759	0.5729	15.44	111.73	67.34
20.000	2.0033	0.1583	1.2499	0.5952	15.83	110.85	67.95
21.000	2.1035	0.1619	1.3241	0.6174	16.19	110.11	68.53

22.000	2.2036	0.1653	1.3987	0.6396	16.53	109.47	69.08
23.000	2.3037	0.1685	1.4733	0.6619	16.85	108.91	69.60
24.000	2.4039	0.1716	1.5482	0.6841	17.16	108.42	70.10
24.960	2.5000	0.1744	1.6199	0.7056	17.44	108.00	70.56

						CUMULATIVE	
	ER OIL	OIL	WATER	HC GAS	SOLVENT	GOR	WOR
YRS	%OOIP	MSTB	MSTB	MMSCF	MMSCF	MSCF/STB	STB/STB
0.000	0.00	0.0	0.0	0.0	0.0	0.000E+00	0.000E+00
1.000	0.00	0.1	205.5	0.1	0.2	0.383E+01	0.287E+04
2.000	1.48	25.6	324.2	20.6	125.1	0.570E+01	0.127E+02
2.493	2.31	39.9	353.9	32.1	245.6	0.696E+01	0.886E+01
3.000	2.98	51.5	388.6	41.5	368.4	0.796E+01	0.754E+01
4.000	4.35	75.2	466.7	60.6	586.9	0.861E+01	0.620E+01
5.000	5.59	96.7	567.7	77.8	760.9	0.867E+01	0.587E+01
6.000	6.68	115.6	676.5	93.0	924.5	0.880E+01	0.585E+01
7.000	7.73	133.6	785.4	107.6	1090.1	0.896E+01	0.588E+01
7.484	8.23	142.4	836.2	114.7	1174.1	0.905E+01	0.587E+01
8.000	8.78	151.8	889.9	122.2	1264.9	0.914E+01	0.586E+01
9.000	9.69	167.6	1013.2	134.9	1404.5	0.918E+01	0.604E+01
10.000	10.47	181.0	1145.0	145.7	1531.4	0.926E+01	0.633E+01
11.000	11.17	193.1	1279.6	155.5	1655.7	0.938E+01	0.663E+01
12.000	11.79	204.0	1415.5	164.2	1780.3	0.953E+01	0.694E+01
13.000	12.42	214.9	1550.3	173.0	1907.6	0.968E+01	0.721E+01
14.000	13.01	225.0	1685.8	181.2	2035.0	0.985E+01	0.749E+01
14.973	13.55	234.4	1817.7	188.7	2160.0	0.100E+02	0.775E+01
15.000	13.57	234.7	1821.4	188.9	2163.4	0.100E+02	0.776E+01
16.000	14.10	243.8	1961.9	196.3	2282.5	0.102E+02	0.805E+01
17.000	14.58	252.2	2110.4	203.0	2385.9	0.103E+02	0.837E+01
18.000	15.03	259.9	2260.6	209.2	2487.2	0.104E+02	0.870E+01
19.000	15.44	267.1	2411.8	215.0	2587.7	0.105E+02	0.903E+01
20.000	15.83	273.8	2563.7	220.4	2688.0	0.106E+02	0.936E+01
21.000	16.19	280.1	2716.0	225.5	2788.3	0.108E+02	0.970E+01
22.000	16.53	285.9	2868.9	230.2	2888.6	0.109E+02	0.100E+02
23.000	16.85	291.5	3022.0	234.7	2989.2	0.111E+02	0.104E+02
24.000	17.16	296.7	3175.5	238.9	3089.9	0.112E+02	0.107E+02
24.960	17.44	301.7	3322.7	242.9	3187.0	0.114E+02	0.110E+02

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SUMMARY OF FLUID PRODUCTION
INCREMENTAL DATA

TIME	********** HCPV OUTPUT ********** HYDROCARBON PORE VOLUMES OUTPUT				OIL RECOVERY
YRS	TOTAL	OIL	WATER	SOLVENT	%OOIP
0.000	0.0000	0.0000	0.0000	0.0000	0.00
1.000	0.1003	0.0000	0.1002	0.0000	0.00
2.000	0.1003	0.0147	0.0579	0.0277	1.47
2.493	0.0494	0.0083	0.0145	0.0267	0.83

3.000	0.0508	0.0067	0.0169	0.0272	0.67
4.000	0.1002	0.0137	0.0381	0.0484	1.37
5.000	0.1002	0.0124	0.0492	0.0385	1.24
6.000	0.1002	0.0109	0.0530	0.0362	1.09
7.000	0.1002	0.0104	0.0531	0.0367	1.04
7.484	0.0485	0.0051	0.0248	0.0186	0.51
8.000	0.0517	0.0054	0.0262	0.0201	0.54
9.000	0.1001	0.0091	0.0601	0.0309	0.91
10.000	0.1001	0.0078	0.0643	0.0281	0.78
11.000	0.1001	0.0070	0.0656	0.0275	0.70
12.000	0.1001	0.0063	0.0663	0.0276	0.63
13.000	0.1001	0.0063	0.0657	0.0282	0.63
14.000	0.1001	0.0059	0.0661	0.0282	0.59
14.973	0.0974	0.0054	0.0643	0.0277	0.54
15.000	0.0027	0.0001	0.0018	0.0008	0.01
16.000	0.1001	0.0053	0.0685	0.0264	0.53
17.000	0.1001	0.0048	0.0724	0.0229	0.48
18.000	0.1001	0.0045	0.0732	0.0224	0.45
19.000	0.1001	0.0042	0.0737	0.0222	0.42
20.000	0.1001	0.0039	0.0740	0.0222	0.39
21.000	0.1001	0.0036	0.0743	0.0222	0.36
22.000	0.1001	0.0034	0.0746	0.0222	0.34
23.000	0.1001	0.0032	0.0746	0.0223	0.32
24.000	0.1001	0.0030	0.0748	0.0223	0.30
24.960	0.0961	0.0029	0.0718	0.0215	0.29

						INCREMENTAL	
	ER OIL	OIL	WATER	HC GAS	SOLVENT	GOR	WOR
YRS	%OOIP	MSTB	MSTB	MMSCF	MMSCF	MSCF/STB	STB/STB
0.000	0.00	0.0	0.0	0.0	0.0	0.000E+00	0.000E+00
1.000	0.00	0.1	205.5	0.1	0.2	0.383E+01	0.287E+04
2.000	1.47	25.5	118.7	20.5	124.9	0.571E+01	0.466E+01
2.493	0.83	14.4	29.6	11.6	120.5	0.920E+01	0.206E+01
3.000	0.67	11.6	34.7	9.3	122.8	0.114E+02	0.299E+01
4.000	1.37	23.7	78.1	19.1	218.5	0.100E+02	0.330E+01
5.000	1.24	21.5	101.0	17.3	174.0	0.891E+01	0.470E+01
6.000	1.09	18.9	108.8	15.2	163.6	0.947E+01	0.576E+01
7.000	1.04	18.0	108.9	14.5	165.6	0.998E+01	0.604E+01
7.484	0.51	8.8	50.9	7.1	84.0	0.104E+02	0.579E+01
8.000	0.54	9.4	53.7	7.5	90.8	0.105E+02	0.572E+01
9.000	0.91	15.8	123.3	12.7	139.6	0.964E+01	0.780E+01
10.000	0.78	13.4	131.9	10.8	126.9	0.103E+02	0.982E+01
11.000	0.70	12.1	134.6	9.7	124.3	0.111E+02	0.111E+02
12.000	0.63	10.9	135.9	8.8	124.7	0.123E+02	0.125E+02
13.000	0.63	10.9	134.7	8.7	127.3	0.125E+02	0.124E+02
14.000	0.59	10.2	135.5	8.2	127.4	0.133E+02	0.133E+02
14.973	0.54	9.4	132.0	7.6	125.0	0.141E+02	0.140E+02
15.000	0.01	0.3	3.7	0.2	3.5	0.147E+02	0.146E+02
16.000	0.53	9.1	140.5	7.3	119.0	0.139E+02	0.154E+02
17.000	0.48	8.3	148.5	6.7	103.4	0.132E+02	0.178E+02
18.000	0.45	7.7	150.2	6.2	101.4	0.139E+02	0.194E+02
19.000	0.42	7.2	151.2	5.8	100.4	0.148E+02	0.210E+02

20.000	0.39	6.7	151.8	5.4	100.4	0.157E+02	0.225E+02
21.000	0.36	6.3	152.4	5.1	100.3	0.168E+02	0.242E+02
22.000	0.34	5.8	152.9	4.7	100.3	0.180E+02	0.262E+02
23.000	0.32	5.6	153.1	4.5	100.6	0.189E+02	0.275E+02
24.000	0.30	5.2	153.5	4.2	100.7	0.201E+02	0.294E+02
24.960	0.29	5.0	147.2	4.0	97.1	0.204E+02	0.297E+02

1.5 HCPV CO_2 WAG CO_2-EOR Scenario

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                 ************** RESERVOIR  DATA **************

            PRESSURE                                      PATTERN
 TEMP       OPERATING    MMP         POROSITY  THICKNESS  AREA
  F           PSIA       PSIA        FRACTION    FEET     ACRES
 123.0       2368.0    1523.0         0.1100     76.0     40.00

                                     INITITAL HC
  FLOOD START SATURATIONS            PORE VOLUME     DYKSTRA-
   OIL         WATER        GAS      HCPV - OOIP     PARSONS    HORIZONTAL
 SOINIT       SWINIT      SGINIT         MMRB         FACTOR       LAYERS
0.3200       0.6800      0.0000         2.0755        0.7300         5

                 *************** FLUID DATA ***************

  STOCK     SOLUTION   SPECIFIC        FORMATION VOLUME FACTOR
 TANK OIL      GOR       GRAVITY      OIL        WATER       SOLVENT
  GRAVITY     (Rs)         SG          Bo          Bw          Bco2
    API      ft3/STB    (Air=1.0)    RB/STB     RB/STB      RB/MMSCF
   36.0       805.0      0.6500      1.2000     1.0119      459.557

 FLUID DENSITIES AT RES T&P          FLUID VISCOSITIES  AT RES T&P     WATER
 RES OIL      WATER      SOLVENT       OIL        WATER       SOLVENT   SALINITY
 GMS/CC       GMS/CC     GMS/CC         cp          cp          cp         ppm
 0.7980       1.0550     0.7248       1.760       0.720       0.068     96000.

          ********** RELATIVE PERMEABILITY PARAMETERS **********

  WTR FLD   GAS FLD     MISC FLD
   SORW      SORG         SORM
 0.3200    0.3200       0.0500

   SGR       SSR                      SWC        SWIR
 0.3200    0.3200                   0.2000     0.2000


  KROCW     KWRO         KRSMAX      KRGCW
 0.4000    0.3000       0.4000      0.4000

  EXPOW     EXPW          EXPS        EXPG        EXPOG
 2.000     2.000        2.000       2.000       2.000


 MIX PARAMETER
   OMEGA         MISCIBLE RELATIVE PERMEABILITY
  0.6660         EQUAL TO Krow
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*********** INJECTION/PRODUCTION PARAMETERS *********

INJECTION SEQUENCES	WAG EXPRESSED AS TIME OR VOL	PATTERN TYPE	INJECTION WELLS	OUTPUT TIME STEPS YEARS
4	V	5S	1	1.000

CUM. INJECT HCPV	INCRE TIME YEARS	CUM. TIME YEARS	SEQUENCE RATE RB/D	AVGE (TOTAL WELLS) INJECTION FRACTIONAL WATER	FLUID CONTENT SOLVENT	WAG WTR:GAS
0.4000	3.989	3.989	569.86	0.0000	1.0000	.0000E+00
1.2000	7.986	11.974	569.28	0.5000	0.5000	.1000E+01
2.4000	11.983	23.957	569.08	0.6667	0.3333	.2000E+01
3.6000	11.985	35.941	568.99	0.7500	0.2500	.3000E+01

INCRE TIME YEARS	CUM. TIME YEARS	AVGE RATE FOR PATTERN ****** SEQUENTIAL ****** RB/D	HCPV/D	HCPV/YR	TOTAL PATTERN SURFACE RATES WATER STB/D	SOLVENT MMSCF/D
3.989	3.989	569.86	0.27456E-03	0.10028	0.0	1.24
7.986	11.974	569.28	0.27428E-03	0.10018	562.0	1.24
11.983	23.957	569.08	0.27418E-03	0.10015	562.0	1.24
11.985	35.941	568.99	0.27414E-03	0.10013	562.0	1.24

**** INJECTION **** INJECTION **** INJECTION **** INJECTION ****
INJECTION

SUMMARY OF FLUID INJECTION
CUMULATIVE DATA

TIME YRS	***** HCPV INPUT ***** TOTAL	WATER	SOLVENT	WATER MSTB	SOLVENT MMSCF
0.000	0.0000	0.0000	0.0000	0.0	0.0
1.000	0.1003	0.0000	0.1003	0.0	452.9
2.000	0.2006	0.0000	0.2006	0.0	905.8
3.000	0.3008	0.0000	0.3008	0.0	1358.8
3.989	0.4000	0.0000	0.4000	0.0	1806.6
4.000	0.4011	0.0006	0.4006	1.2	1809.1
5.000	0.5013	0.0507	0.4507	103.9	2035.3
6.000	0.6015	0.1007	0.5007	206.6	2261.6
7.000	0.7017	0.1508	0.5508	309.4	2487.8
8.000	0.8019	0.2009	0.6009	412.1	2714.0
9.000	0.9020	0.2510	0.6510	514.9	2940.3
10.000	1.0022	0.3011	0.7011	617.6	3166.5
11.000	1.1024	0.3512	0.7512	720.4	3392.7
11.974	1.2000	0.4000	0.8000	820.5	3613.1

12.000	1.2026	0.4017	0.8009	824.0	3617.0
13.000	1.3027	0.4685	0.8342	960.9	3767.8
14.000	1.4029	0.5352	0.8676	1097.9	3918.5
15.000	1.5030	0.6020	0.9010	1234.8	4069.3
16.000	1.6032	0.6688	0.9344	1371.7	4220.1
17.000	1.7033	0.7355	0.9678	1508.7	4370.8
18.000	1.8034	0.8023	1.0011	1645.6	4521.6
19.000	1.9036	0.8691	1.0345	1782.6	4672.4
20.000	2.0037	0.9358	1.0679	1919.5	4823.1
21.000	2.1039	1.0026	1.1013	2056.5	4973.9
22.000	2.2040	1.0694	1.1347	2193.4	5124.7
23.000	2.3042	1.1361	1.1681	2330.3	5275.4
23.957	2.4000	1.2000	1.2000	2461.4	5419.7
24.000	2.4043	1.2032	1.2011	2468.0	5424.6
25.000	2.5044	1.2783	1.2261	2622.1	5537.6
26.000	2.6046	1.3534	1.2511	2776.1	5650.7
27.000	2.7047	1.4285	1.2762	2930.1	5763.7
28.000	2.8048	1.5036	1.3012	3084.2	5876.8
29.000	2.9050	1.5787	1.3262	3238.2	5989.8
30.000	3.0051	1.6538	1.3513	3392.2	6102.9
31.000	3.1052	1.7289	1.3763	3546.3	6216.0
32.000	3.2053	1.8040	1.4013	3700.3	6329.0
33.000	3.3055	1.8791	1.4264	3854.3	6442.1
34.000	3.4056	1.9542	1.4514	4008.4	6555.1
35.000	3.5057	2.0293	1.4764	4162.4	6668.2
35.941	3.6000	2.1000	1.5000	4307.4	6774.6

*** PRODUCTION ***** PRODUCTION ***** PRODUCTION ***** PRODUCTION ***

SUMMARY OF FLUID PRODUCTION
CUMULATIVE DATA

TIME	********** HCPV OUTPUT ********** HYDROCARBON PORE VOLUMES OUTPUT				OIL RECOVERY	RECOVERY % OF INJECTANT	
YRS	TOTAL	OIL	WATER	SOLVENT	%OOIP	WATER	SOLVENT
0.000	0.0000	0.0000	0.0000	0.0000	0.00	0.00	0.00
1.000	0.1003	0.0000	0.1002	0.0000	0.00	0.00	0.05
2.000	0.2006	0.0148	0.1581	0.0277	1.48	0.00	13.81
3.000	0.3008	0.0295	0.1852	0.0861	2.95	0.00	28.61
3.989	0.4000	0.0394	0.2036	0.1570	3.94	0.00	39.25
4.000	0.4011	0.0395	0.2038	0.1578	3.95	******	39.41
5.000	0.5013	0.0504	0.2282	0.2228	5.04	450.51	49.43
6.000	0.6015	0.0618	0.2635	0.2762	6.18	261.58	55.15
7.000	0.7017	0.0720	0.3122	0.3174	7.20	207.00	57.63
8.000	0.8019	0.0818	0.3634	0.3567	8.18	180.87	59.35
9.000	0.9020	0.0917	0.4132	0.3971	9.17	164.60	61.00
10.000	1.0022	0.1007	0.4634	0.4381	10.07	153.91	62.49
11.000	1.1024	0.1090	0.5140	0.4793	10.90	146.37	63.81
11.974	1.2000	0.1165	0.5639	0.5196	11.65	140.98	64.95
12.000	1.2026	0.1167	0.5652	0.5207	11.67	140.70	65.01
13.000	1.3027	0.1241	0.6201	0.5585	12.41	132.36	66.95

14.000	1.4029	0.1314	0.6815	0.5900	13.14	127.32	68.01
15.000	1.5030	0.1378	0.7444	0.6208	13.78	123.66	68.90
16.000	1.6032	0.1436	0.8089	0.6507	14.36	120.95	69.64
17.000	1.7033	0.1487	0.8744	0.6802	14.87	118.88	70.28
18.000	1.8034	0.1535	0.9401	0.7098	15.35	117.18	70.90
19.000	1.9036	0.1581	1.0059	0.7396	15.81	115.74	71.49
20.000	2.0037	0.1624	1.0721	0.7692	16.24	114.57	72.03
21.000	2.1039	0.1664	1.1385	0.7990	16.64	113.55	72.55
22.000	2.2040	0.1701	1.2050	0.8289	17.01	112.68	73.06
23.000	2.3042	0.1736	1.2716	0.8590	17.36	111.93	73.54
23.957	2.4000	0.1769	1.3355	0.8877	17.69	111.29	73.97
24.000	2.4043	0.1770	1.3384	0.8889	17.70	111.23	74.01
25.000	2.5044	0.1806	1.4066	0.9172	18.06	110.04	74.81
26.000	2.6046	0.1839	1.4788	0.9418	18.39	109.27	75.28
27.000	2.7047	0.1870	1.5522	0.9655	18.70	108.66	75.66
28.000	2.8048	0.1898	1.6260	0.9890	18.98	108.14	76.00
29.000	2.9050	0.1925	1.7001	1.0123	19.25	107.69	76.33
30.000	3.0051	0.1951	1.7744	1.0356	19.51	107.29	76.64
31.000	3.1052	0.1976	1.8487	1.0589	19.76	106.93	76.94
32.000	3.2053	0.2000	1.9232	1.0822	20.00	106.61	77.22
33.000	3.3055	0.2023	1.9977	1.1055	20.23	106.31	77.50
34.000	3.4056	0.2045	2.0723	1.1288	20.45	106.04	77.78
35.000	3.5057	0.2067	2.1468	1.1523	20.67	105.79	78.04
35.941	3.6000	0.2087	2.2170	1.1743	20.87	105.57	78.29

						CUMULATIVE	
	ER OIL	OIL	WATER	HC GAS	SOLVENT	GOR	WOR
YRS	%OOIP	MSTB	MSTB	MMSCF	MMSCF	MSCF/STB	STB/STB
0.000	0.00	0.0	0.0	0.0	0.0	0.000E+00	0.000E+00
1.000	0.00	0.1	205.5	0.1	0.2	0.383E+01	0.287E+04
2.000	1.48	25.6	324.2	20.6	125.1	0.570E+01	0.127E+02
3.000	2.95	51.1	379.9	41.1	388.8	0.841E+01	0.744E+01
3.989	3.94	68.1	417.7	54.8	709.0	0.112E+02	0.613E+01
4.000	3.95	68.3	418.0	55.0	712.9	0.112E+02	0.612E+01
5.000	5.04	87.1	468.1	70.1	1006.0	0.124E+02	0.537E+01
6.000	6.18	106.9	540.5	86.0	1247.3	0.125E+02	0.506E+01
7.000	7.20	124.5	640.4	100.2	1433.7	0.123E+02	0.514E+01
8.000	8.18	141.4	745.4	113.9	1610.8	0.122E+02	0.527E+01
9.000	9.17	158.7	847.5	127.7	1793.6	0.121E+02	0.534E+01
10.000	10.07	174.1	950.6	140.2	1978.7	0.122E+02	0.546E+01
11.000	10.90	188.6	1054.4	151.8	2164.8	0.123E+02	0.559E+01
11.974	11.65	201.5	1156.7	162.2	2346.7	0.125E+02	0.574E+01
12.000	11.67	201.8	1159.4	162.5	2351.5	0.125E+02	0.574E+01
13.000	12.41	214.7	1271.9	172.8	2522.5	0.126E+02	0.592E+01
14.000	13.14	227.2	1397.8	182.9	2664.9	0.125E+02	0.615E+01
15.000	13.78	238.4	1526.9	191.9	2803.6	0.126E+02	0.640E+01
16.000	14.36	248.4	1659.2	199.9	2938.7	0.126E+02	0.668E+01
17.000	14.87	257.3	1793.5	207.1	3071.9	0.127E+02	0.697E+01
18.000	15.35	265.6	1928.3	213.8	3205.7	0.129E+02	0.726E+01
19.000	15.81	273.5	2063.2	220.2	3340.3	0.130E+02	0.754E+01
20.000	16.24	280.9	2199.1	226.1	3474.1	0.132E+02	0.783E+01
21.000	16.64	287.7	2335.2	231.6	3608.8	0.133E+02	0.812E+01

22.000	17.01	294.2	2471.6	236.8	3743.9	0.135E+02	0.840E+01
23.000	17.36	300.2	2608.3	241.7	3879.4	0.137E+02	0.869E+01
23.957	17.69	305.9	2739.2	246.3	4009.1	0.139E+02	0.895E+01
24.000	17.70	306.2	2745.2	246.5	4014.8	0.139E+02	0.897E+01
25.000	18.06	312.3	2885.2	251.4	4142.6	0.141E+02	0.924E+01
26.000	18.39	318.1	3033.3	256.1	4253.6	0.142E+02	0.954E+01
27.000	18.70	323.4	3183.8	260.3	4360.8	0.143E+02	0.984E+01
28.000	18.98	328.3	3335.2	264.3	4466.6	0.144E+02	0.102E+02
29.000	19.25	333.0	3487.2	268.1	4571.9	0.145E+02	0.105E+02
30.000	19.51	337.5	3639.5	271.7	4677.1	0.147E+02	0.108E+02
31.000	19.76	341.8	3792.0	275.2	4782.3	0.148E+02	0.111E+02
32.000	20.00	345.9	3944.8	278.4	4887.5	0.149E+02	0.114E+02
33.000	20.23	349.8	4097.6	281.6	4992.8	0.151E+02	0.117E+02
34.000	20.45	353.7	4250.5	284.7	5098.3	0.152E+02	0.120E+02
35.000	20.67	357.5	4403.4	287.8	5204.1	0.154E+02	0.123E+02
35.941	20.87	360.9	4547.4	290.5	5303.8	0.155E+02	0.126E+02

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SUMMARY OF FLUID PRODUCTION
INCREMENTAL DATA

	********** HCPV OUTPUT **********				OIL
TIME	HYDROCARBON PORE VOLUMES OUTPUT				RECOVERY
YRS	TOTAL	OIL	WATER	SOLVENT	%OOIP
0.000	0.0000	0.0000	0.0000	0.0000	0.00
1.000	0.1003	0.0000	0.1002	0.0000	0.00
2.000	0.1003	0.0147	0.0579	0.0277	1.47
3.000	0.1003	0.0148	0.0272	0.0584	1.48
3.989	0.0992	0.0098	0.0184	0.0709	0.98
4.000	0.0011	0.0001	0.0002	0.0009	0.01
5.000	0.1002	0.0109	0.0244	0.0649	1.09
6.000	0.1002	0.0114	0.0353	0.0534	1.14
7.000	0.1002	0.0102	0.0487	0.0413	1.02
8.000	0.1002	0.0098	0.0512	0.0392	0.98
9.000	0.1002	0.0099	0.0498	0.0405	0.99
10.000	0.1002	0.0089	0.0503	0.0410	0.89
11.000	0.1002	0.0084	0.0506	0.0412	0.84
11.974	0.0976	0.0074	0.0499	0.0403	0.74
12.000	0.0026	0.0002	0.0013	0.0011	0.02
13.000	0.1001	0.0075	0.0548	0.0378	0.75
14.000	0.1001	0.0072	0.0614	0.0315	0.72
15.000	0.1001	0.0065	0.0630	0.0307	0.65
16.000	0.1001	0.0057	0.0645	0.0299	0.57
17.000	0.1001	0.0052	0.0655	0.0295	0.52
18.000	0.1001	0.0048	0.0657	0.0296	0.48
19.000	0.1001	0.0046	0.0658	0.0298	0.46
20.000	0.1001	0.0042	0.0663	0.0296	0.42
21.000	0.1001	0.0040	0.0664	0.0298	0.40
22.000	0.1001	0.0037	0.0665	0.0299	0.37
23.000	0.1001	0.0035	0.0666	0.0300	0.35
23.957	0.0958	0.0033	0.0638	0.0287	0.33

24.000	0.0043	0.0001	0.0029	0.0013	0.01
25.000	0.1001	0.0036	0.0683	0.0283	0.36
26.000	0.1001	0.0033	0.0722	0.0246	0.33
27.000	0.1001	0.0030	0.0733	0.0237	0.30
28.000	0.1001	0.0029	0.0738	0.0234	0.29
29.000	0.1001	0.0027	0.0741	0.0233	0.27
30.000	0.1001	0.0026	0.0742	0.0233	0.26
31.000	0.1001	0.0025	0.0743	0.0233	0.25
32.000	0.1001	0.0024	0.0745	0.0233	0.24
33.000	0.1001	0.0023	0.0745	0.0233	0.23
34.000	0.1001	0.0022	0.0745	0.0234	0.22
35.000	0.1001	0.0022	0.0745	0.0234	0.22
35.941	0.0943	0.0020	0.0702	0.0221	0.20

		INCREMENTAL					
	ER OIL	OIL	WATER	HC GAS	SOLVENT	GOR	WOR
YRS	%OOIP	MSTB	MSTB	MMSCF	MMSCF	MSCF/STB	STB/STB
0.000	0.00	0.0	0.0	0.0	0.0	0.000E+00	0.000E+00
1.000	0.00	0.1	205.5	0.1	0.2	0.383E+01	0.287E+04
2.000	1.47	25.5	118.7	20.5	124.9	0.571E+01	0.466E+01
3.000	1.48	25.5	55.7	20.6	263.6	0.111E+02	0.218E+01
3.989	0.98	17.0	37.7	13.7	320.3	0.196E+02	0.222E+01
4.000	0.01	0.2	0.4	0.1	3.9	0.232E+02	0.208E+01
5.000	1.09	18.8	50.1	15.1	293.1	0.164E+02	0.266E+01
6.000	1.14	19.8	72.5	15.9	241.3	0.130E+02	0.366E+01
7.000	1.02	17.7	99.9	14.2	186.4	0.114E+02	0.566E+01
8.000	0.98	16.9	105.0	13.6	177.1	0.113E+02	0.620E+01
9.000	0.99	17.2	102.1	13.9	182.8	0.114E+02	0.593E+01
10.000	0.89	15.5	103.1	12.4	185.1	0.128E+02	0.667E+01
11.000	0.84	14.5	103.8	11.7	186.1	0.136E+02	0.716E+01
11.974	0.74	12.9	102.3	10.4	181.9	0.149E+02	0.795E+01
12.000	0.02	0.3	2.7	0.3	4.8	0.154E+02	0.820E+01
13.000	0.75	12.9	112.5	10.4	170.9	0.141E+02	0.873E+01
14.000	0.72	12.5	125.9	10.1	142.4	0.122E+02	0.101E+02
15.000	0.65	11.2	129.1	9.0	138.7	0.132E+02	0.115E+02
16.000	0.57	9.9	132.3	8.0	135.1	0.144E+02	0.133E+02
17.000	0.52	8.9	134.4	7.2	133.2	0.157E+02	0.151E+02
18.000	0.48	8.3	134.8	6.7	133.9	0.170E+02	0.163E+02
19.000	0.46	8.0	134.9	6.4	134.6	0.177E+02	0.170E+02
20.000	0.42	7.4	135.9	5.9	133.9	0.190E+02	0.185E+02
21.000	0.40	6.9	136.1	5.5	134.6	0.204E+02	0.198E+02
22.000	0.37	6.4	136.4	5.2	135.1	0.218E+02	0.212E+02
23.000	0.35	6.1	136.7	4.9	135.5	0.232E+02	0.226E+02
23.957	0.33	5.7	130.9	4.6	129.7	0.236E+02	0.230E+02
24.000	0.01	0.3	5.9	0.2	5.8	0.231E+02	0.229E+02
25.000	0.36	6.2	140.1	5.0	127.8	0.216E+02	0.228E+02
26.000	0.33	5.8	148.1	4.7	111.0	0.200E+02	0.256E+02
27.000	0.30	5.3	150.4	4.2	107.2	0.211E+02	0.285E+02
28.000	0.29	4.9	151.5	4.0	105.8	0.222E+02	0.307E+02
29.000	0.27	4.7	152.0	3.8	105.3	0.233E+02	0.324E+02
30.000	0.26	4.5	152.3	3.6	105.2	0.241E+02	0.338E+02
31.000	0.25	4.3	152.5	3.5	105.2	0.253E+02	0.355E+02

32.000	0.24	4.1	152.8	3.3	105.2	0.266E+02	0.375E+02
33.000	0.23	3.9	152.9	3.2	105.3	0.275E+02	0.388E+02
34.000	0.22	3.9	152.9	3.1	105.5	0.281E+02	0.395E+02
35.000	0.22	3.8	152.8	3.1	105.8	0.286E+02	0.402E+02
35.941	0.20	3.4	144.0	2.8	99.7	0.299E+02	0.421E+02

Appendix D: United States Environmental Protection Agency AP-42 Emissions Factors for the Onshore Oil and Gas Industry

Table D-1: AP-42 Methane CH_4 Emissions Factors for the Oil and Gas Industry

Activity/Equipment	Emission Factor	EF Units
Vented Emissions		
Oil Tanks	5.28	scf of CH_4/bbl crude
Pneumatic Devices, High Bleed	330	scfd CH_4/device
Pneumatic Devices, Low Bleed	52	scfd CH_4/device
Chemical Injection Pumps	248	scfd CH_4 /pump
Vessel Blowdowns	78	scfy CH_4/vessel
Compressor Blowdowns	3,775	scf/yr of CH_4/compressor
Compressor Starts	8,443	scf/yr. of CH_4/compressor
Stripper wells	2,345	scf/yr of CH_4/stripper well
Well Completion Venting	733	scf/completion
Well Workovers	96	scf CH_4/workover
Pipeline Pigging	2.4	scfd of CH_4/pig station
Fugitive Emissions		
Oil Wellheads (heavy crude)	0.13	scfd/well
Oil Wellheads (light crude)	16.6	scfd/well
Separators (heavy crude)	0.15	scfd CH4/separator
Separators (light crude)	14	scfd CH4/separator
Heater/Treaters (light crude)	19	scfd CH4/heater
Headers (heavy crude)1	0.08	scfd CH4/header
Headers (light crude)	11	scfd CH4/header
Floating Roof Tanks	338,306	scf CH4/floating roof tank/yr.
Compressors	100	scfd CH4/compressor
Large Compressors	16,360	scfd CH4/compressor
Sales Areas	41	scf CH4/loading
Pipelines	NE	scfd of CH4/mile of pipeline
Well Drilling	NE	scfd of CH4/oil well drilled
Battery Pumps	0.24	scfd of CH4/pump
Combustion Emissions		
Gas Engines	0.24	scf CH4/HP-hr
Heaters	0.52	scf CH4/bbl
Well Drilling	2,453	scf CH4/well drilled
Flares	20	scf CH4/Mcf flared
Process Upset Emissions		
Pressure Relief Valves	35	scf/yr/PR valve
Well Blowouts Onshore	2.5	MMscf/blowout

Table D-2: AP-42 CO_2 Emissions Factors for the Oil and Gas Industry

CO_2 Emissions		
Activity/Equipment	**Emission Factor**	**EF Units**
Vented Emissions		
Oil Tanks	3.53	scf of CO_2/bbl crude
Pneumatic Devices, High Bleed	6.704	scfd CO_2/device
Pneumatic Devices, Low Bleed	1.055	scfd CO_2/device
Chemical Injection Pumps	5.033	scfd CO_2/pump
Vessel Blowdowns1	1.583	scfy CO_2/vessel
Compressor Blowdowns1	77	scf/yr of CO_2/compressor
Compressor Starts1	171	scf/yr of CO_2/compressor
Stripper wells	48	scf/yr of CO_2/stripper well
Well Completion Venting1	14.87	Scf CO_2/completion
Well Workovers	1.95	scf CO_2/workover
Pipeline Pigging	NE	scfd of CO_2/pig station
Fugitive Emissions		
Oil Wellheads (heavy crude)1	0.003	scfd/well
Oil Wellheads (light crude)	0.337	scfd/well
Separators (heavy crude)1	0.003	scfd CO_2/separator
Separators (light crude)	0.281	scfd CO_2/separator
Heater/Treaters (light crude)	0.319	scfd CO_2/heater
Headers (heavy crude)1	0.002	scfd CO_2/header
Headers (light crude)	0.22	scfd CO_2/header
Floating Roof Tanks1	17,490	scf CO_2/floating roof tank/yr.
Compressors	2.029	scfd CO_2/compressor
Large Compressors	332	scfd CO_2/compressor
Sales Areas	2.096	scf CO_2/loading
Pipelines	NE	scfd of CO_2/mile of pipeline
Well Drilling	NE	scfd of CO_2/oil well drilled
Battery Pumps	0.012	scfd of CO_2/pump
Process Upset Emissions		
Pressure Relief Valves1	1.794	scf/yr/PR valve
Well Blowouts Onshore	0.051	MMscf/blowout

Appendix E: Summary Output form U.S. EPA TANKS Model of Oil Storage Tanks for Historical, Best Practices, and 1.5 HCPV CO_2 WAG CO_2-EOR Scenarios.

Historical CO_2-EOR

a)Estimated Annual Working and Breathing Losses of Single Oil Tank Under Historical CO_2-EOR Scenario Conditions

TANKS 4.0.9d

Emissions Report - Summary Format

Tank Indentification and Physical Characteristics

Identification	
User Identification:	1.0 HCPV WAG
City:	Midland-Odessa
State:	Texas
Company:	
Type of Tank:	Vertical Fixed Roof Tank
Description:	Working and Breathing losses for 1.5 HCPV CO_2 WAG Scenario
Tank Dimensions	
Shell Height (ft):	15.00
Diameter (ft):	12.00
Liquid Height (ft) :	15.00
Avg. Liquid Height (ft):	12.00
Volume (gallons):	12,690.44
Turnovers:	467.00
Net Throughput(gal/yr):	6,299,743.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	2.00
Radius (ft) (Dome Roof)	12.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Midland-Odessa, Texas (Avg Atmospheric Pressure = 13.28 psia)

TANKS 4.0.9d

Emissions Report - Summary Format
Liquid Contents of Storage Tank

i)**1.0 HCPV WAG - Vertical Fixed Roof Tank**
Midland-Odessa, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	65.56	58.52	72.59	63.30	3.2058	2.7953	3.6634	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

k)**Emissions Report for: Annual**

l)**1.0 HCPV WAG - Vertical Fixed Roof Tank**
Midland-Odessa, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	4,163.72	376.04	4,539.76

b) Estimated Annual Working and Breathing Losses of Heater/Treater Under Historical CO_2-EOR Scenario Conditions

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	1HCPV__HT_TANK_1
City:	Midland-Odessa
State:	Texas
Company:	

Type of Tank:	Vertical Fixed Roof Tank	
Description:	Estimation of Working and Standing Losses for 0.4 HCPV CO_2_EOR Scenario	
Tank Dimensions		
Shell Height (ft):		12.00
Diameter (ft):		6.00
Liquid Height (ft) :		8.00
Avg. Liquid Height (ft):		8.00
Volume (gallons):		1,692.06
Turnovers:		7,399.00
Net Throughput(gal/yr):		13,020,395.90
Is Tank Heated (y/n):	Y	
Paint Characteristics		
Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	
Roof Characteristics		
Type:	Dome	
Height (ft)		2.00
Radius (ft) (Dome Roof)		6.00
Breather Vent Settings		
Vacuum Settings (psig):		0.00
Pressure Settings (psig)		0.00

Meterological Data used in Emissions Calculations: Midland-Odessa, Texas (Avg Atmospheric Pressure = 13.28 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

1HCPV__HT_TANK_1 - Vertical Fixed Roof Tank
Midland-Odessa, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	68.65	59.43	77.87	140.00	3.4009	2.8455	4.0400	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

1HCPV__HT_TANK_1 - Vertical Fixed Roof Tank
Midland-Odessa, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	6,749.82	128.78	6,878.59

Best Practices CO_2-EOR

a)Estimated Annual Working and Breathing Losses of Single Oil Tank Under Best Practices CO_2-EOR Scenario Conditions

TANKS 4.0.9d

Emissions Report - Summary Format

Tank Indentification and Physical Characteristics

Identification	
User Identification:	1.0 HCPV WAG
City:	Midland-Odessa
State:	Texas
Company:	
Type of Tank:	Vertical Fixed Roof Tank
Description:	Working and Breathing losses for 1.5 HCPV CO_2 WAG Scenario
Tank Dimensions	
Shell Height (ft):	15.00
Diameter (ft):	12.00
Liquid Height (ft) :	15.00
Avg. Liquid Height (ft):	12.00
Volume (gallons):	12,690.44
Turnovers:	521.00
Net Throughput(gal/yr):	6,299,743.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	2.00

Radius (ft) (Dome Roof)	12.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Midland-Odessa, Texas (Avg Atmospheric Pressure = 13.28 psia)

TANKS 4.0.9d

Emissions Report - Summary Format

Liquid Contents of Storage Tank

1.0 HCPV WAG - Vertical Fixed Roof Tank
Midland-Odessa, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	65.56	58.52	72.59	63.30	3.2058	2.7953	3.6634	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d

Emissions Report - Summary Format

Individual Tank Emission Totals

Emissions Report for: Annual

1.0 HCPV WAG - Vertical Fixed Roof Tank
Midland-Odessa, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	4,043.66	376.04	4,419.70

b)Estimated Annual Working and Breathing Losses of Heater/Treater Under Best Practices CO_2-EOR Scenario Conditions

TANKS 4.0.9d

Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	1HCPV__HT_TANK_1	
City:	Midland-Odessa	
State:	Texas	
Company:		
Type of Tank:	Vertical Fixed Roof Tank	
Description:	Estimation of Working and Standing Losses for 1.0 HCPV CO_2_EOR Scenario	
Tank Dimensions		
Shell Height (ft):		12.00
Diameter (ft):		6.00
Liquid Height (ft) :		8.00
Avg. Liquid Height (ft):		8.00
Volume (gallons):		1,692.06
Turnovers:		7,695.00
Net Throughput(gal/yr):		13,020,395.90
Is Tank Heated (y/n):	Y	
Paint Characteristics		
Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	
Roof Characteristics		
Type:	Dome	
Height (ft)		2.00
Radius (ft) (Dome Roof)		6.00
Breather Vent Settings		
Vacuum Settings (psig):		0.00
Pressure Settings (psig)		0.00

Meterological Data used in Emissions Calculations: Midland-Odessa, Texas (Avg Atmospheric Pressure = 13.28 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

1HCPV__HT_TANK_1 - Vertical Fixed Roof Tank
Midland-Odessa, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	68.65	59.43	77.87	140.00	3.4009	2.8455	4.0400	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

1HCPV__HT_TANK_1 - Vertical Fixed Roof Tank
Midland-Odessa, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	6,743.65	128.78	6,872.43

1.5 HCPV CO_2 WAG CO_2-EOR

a) Estimate Annual Working and Breathing Losses of Oil Tank Under 1.5 HCPV CO_2 WAG CO_2-EOR Scenario

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	1.5 HCPV WAG
City:	Midland-Odessa
State:	Texas
Company:	
Type of Tank:	Vertical Fixed Roof Tank
Description:	Working and Breathing losses for 1.5 HCPV CO2 WAG Scenario
Tank Dimensions	
Shell Height (ft):	15.00
Diameter (ft):	12.00
Liquid Height (ft) :	15.00
Avg. Liquid Height (ft):	12.00
Volume (gallons):	12,690.44
Turnovers:	496.00
Net Throughput(gal/yr):	6,299,743.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Color/Shade: White/White
Roof Condition: Good

Roof Characteristics

Type: Dome
Height (ft) 2.00
Radius (ft) (Dome Roof) 12.00

Breather Vent Settings

Vacuum Settings (psig): -0.03
Pressure Settings (psig) 0.03

Meterological Data used in Emissions Calculations: Midland-Odessa, Texas (Avg Atmospheric Pressure = 13.28 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

1.5 HCPV WAG - Vertical Fixed Roof Tank
Midland-Odessa, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	65.56	58.52	72.59	63.30	3.2058	2.7953	3.6634	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

- Vertical Fixed Roof Tank
Midland-Odessa, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	4,095.99	376.04	4,472.03

b)Estimated Annual Working and Breathing Losses of Heater/Treater Under 1.5 HCPV CO_2 WAG CO_2-EOR Scenario Conditions

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	1HCPV__HT_TANK_1
City:	Midland-Odessa
State:	Texas
Company:	
Type of Tank:	Vertical Fixed Roof Tank
Description:	Estimation of Working and Standing Losses for 1.0 HCPV CO2_EOR Scenario
Tank Dimensions	
Shell Height (ft):	12.00
Diameter (ft):	6.00
Liquid Height (ft) :	8.00
Avg. Liquid Height (ft):	8.00
Volume (gallons):	1,692.06
Turnovers:	7,137.00
Net Throughput(gal/yr):	13,020,395.90
Is Tank Heated (y/n):	Y
Paint Characteristics	
Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	2.00
Radius (ft) (Dome Roof)	6.00
Breather Vent Settings	
Vacuum Settings (psig):	0.00
Pressure Settings (psig)	0.00

Meterological Data used in Emissions Calculations: Midland-Odessa, Texas (Avg Atmospheric Pressure = 13.28 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

1HCPV__HT_TANK_1 - Vertical Fixed Roof Tank
Midland-Odessa, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	68.65	59.43	77.87	140.00	3.4009	2.8455	4.0400	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

1HCPV__HT_TANK_1 - Vertical Fixed Roof Tank
Midland-Odessa, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	6,755.70	128.78	6,884.48

Appendix F: Drill Rig Specifications

http://patdrilling.com/pdf/rigs/472.pdf

RIG #472

DRAWWORKS
National 370-M (550HP)
1 1/8” drill line, Parmac 22-SR auxiliary brake

POWER
(2) Caterpillar 3408 engines (475HP each)

LIGHT PLANTS
(2) Caterpillar 3406 engines w/ 210 KW generators

MAST
DSI 132’ w/ 322,000# capacity on 8 lines

SUBSTRUCTURE
DSI 14’ box
KB 13’ 6” Rotary beam clearance 9’ 4”

BLOCK HOOK
McKissick (250 Ton) block
Web Wilson (200 Ton) hook

PUMPS
(2) Continental Emsco DB-550 (550HP each) duplex pumps
(1) Powered by a Caterpillar 379 engine
(1) Powered by a Caterpillar 353 engine

BOP’S
11” X 3,000 psi Shaffer double

ACCUMULATOR
Koomey 5-Station, 80 gallon accumulator

CHOKE MANIFOLD
3,000 psi choke manifold

SWIVEL
Ideco (300 Ton)

ROTARY TABLE
Gardner Denver (17 1/2”)

DRILL PIPE 4 1/2” drill pipe

DRILL COLLARS
8” and 6 1/2” drill collars *quantity subject to availibility

AUXILIARY EQUIPMENT
Pason EDR (base system)
Water Tank - (2) 500 barrel capacity each
Rig Manager Quarters Satellite automatic driller
Mathey survey unit

Appendix G: Life Cycle Emissions Profile of 434-$MW_{electric}$ (MWe) Existing PC Facility

Table G-1: Life Cycle Emissions Profile of 434-megawatt electric (MWe) Existing PC Thermoelectric generation facility with and without 90 percent CO_2 Capture.

Emissions (kg CO_2e /MWh)	**Stage #1: Raw Material Acquisition**	**Stage #2: Raw Material Transport**	**Stage #3: Power Plant**	**Stage #4: Transmission & Distribution**	**Total**
Case 1-EXPC Without CCS					
CO_2	3.2	5.2	1.0E+03	0	1020
N_2O	1.4E-02	3.7E-02	5.1	0	5.1
CH_4	80	1.9E-01	2.8E-01	0	80
SF_6	4.3E-07	6.0E-08	6.3E-03	3.3	3.3
Total GWP	83	5.4	1017	3.3	1109
Case 2-EXPC With CCS					
CO_2	3.2	5.2	340	0	348
N_2O	1.4E-02	3.7E-02	6.0	0	6.0
CH_4	8.0E+01	1.9E-01	6.6	0	87
SF_6	4.3E-07	6.0E-08	4.5E-03	3.3	3.3
Total GWP	83	5.4	353	3.3	444

Appendix H: Tabular Listing of Summary Data for Three Operational Scenarios

Table H-1: Summary of emissions and resource demands for historical CO_2-EOR scenario.

Parameter	Units	Site Eval. & Char.	Construction	Operation	Closure	MVA	Total
Greenhouse Gas Emissions							
CO_2	kg/bbl crude	3.49E-03	3.24E-01	4.88E+01	1.83E-01	6.99E-03	4.93E+01
CH_4	kg/bbl crude	0.00E+00	5.79E-05	8.84E-02	1.87E-06	0.00E+00	8.85E-02
N_2O	kg/bbl crude	0.00E+00	0.00E+00	2.13E-04	0.00E+00	0.00E+00	2.13E-04
SF_6	kg/bbl crude	0.00E+00	0.00E+00	2.18E-11	0.00E+00	0.00E+00	2.18E-11
CO_2E*	kg/bbl crude	3.67E-03	3.36E-01	5.01E+01	1.90E-01	7.35E-03	5.06E+01
Criteria Air Pollutants							
NO_X	kg/bbl crude	1.61E-05	1.29E-03	2.90E-02	7.95E-04	3.22E-05	3.11E-02
CO	kg/bbl crude	8.55E-06	7.22E-04	4.28E-02	4.09E-04	1.71E-05	4.40E-02
PM (Total)	kg/bbl crude	4.09E-07	3.38E-03	1.27E-03	1.22E-04	8.18E-07	4.77E-03
Lead	kg/bbl crude	0.00E+00	0.00E+00	6.36E-07	0.00E+00	0.00E+00	6.36E-07
SO_2	kg/bbl crude	2.92E-10	7.68E-04	8.37E-02	9.55E-05	5.84E-10	8.46E-02
VOC	kg/bbl crude	1.08E-06	7.10E-05	1.32E-01	4.94E-05	2.15E-06	1.32E-01
Water Use							
Fresh water consumption	bbl/bbl crude	0.00E+00	4.49E-03	2.47E-01	9.70E-04	0.00E+00	2.52E-01
Excess Brine for Injection Disposal	barrel excess brine per bbl crude	-	-	5.27E-01	-	-	5.27E-01
CO_2 Sequestered (gross)							
CO_2 stored	kg/bbl crude	-	-	195	-	-	195
Land Use							
Pattern Area	Acres/bbl crude	-	-	2.09E-04	-	-	2.09E-04

* CO_2 equivalent values are aggregate values including credits and upstream emissions for which only CO_2E values are available. Individual GHG constituent values will not correspond directly with the reported total global warming potential.

Table H-2: Summary of emissions and resource demands for best practices CO_2-EOR scenario.

Parameter	Units	Site Eval. & Char.	Construction	Operation	Closure	MVA	Total
Greenhouse Gas Emissions							
CO_2	kg/bbl crude	2.22E-03	2.99E-01	6.88E+01	1.16E-01	4.44E-03	6.92E+01
CH_4	kg/bbl crude	0.00E+00	6.08E-05	7.95E-02	1.19E-06	0.00E+00	7.96E-02
N_2O	kg/bbl crude	0.00E+00	0.00E+00	2.01E-04	0.00E+00	0.00E+00	2.01E-04
SF_6	kg/bbl crude	0.00E+00	0.00E+00	1.84E-11	0.00E+00	0.00E+00	1.84E-11
CO_2E*	kg/bbl crude	2.33E-03	3.12E-01	7.03E+01	1.21E-01	4.67E-03	7.07E+01
Criteria Air Pollutants							
NO_X	kg/bbl crude	1.02E-05	1.26E-03	2.77E-02	5.05E-04	2.04E-05	2.95E-02
CO	kg/bbl crude	5.43E-06	6.90E-04	7.31E-02	2.59E-04	1.09E-05	7.41E-02
PM (Total)	kg/bbl crude	2.60E-07	3.11E-03	1.21E-03	7.76E-05	5.19E-07	4.39E-03
Lead	kg/bbl crude	0.00E+00	0.00E+00	5.17E-07	0.00E+00	0.00E+00	5.17E-07
SO_2	kg/bbl crude	1.95E-10	6.41E-04	8.35E-02	6.06E-05	3.90E-10	8.42E-02
VOC	kg/bbl crude	6.83E-07	7.35E-05	5.20E-02	3.13E-05	1.37E-06	5.21E-02
Water Use							
Fresh water consumption	kg/bbl crude	0.00E+00	4.17E-03	2.07E-01	6.15E-04	0.00E+00	2.12E-01
Excess Brine for Injection Disposal	barrel excess brine per bbl crude	-	-	8.15E-01	-	-	8.15E-01
CO_2 Sequestered (gross)							
CO_2 stored	kg CO_2/bbl crude	-	-	228	-	-	228
Land Use							
Land use	Acres/bbl crude	-	-	1.33E-04	-	-	1.33E-04

* CO_2 equivalent values are aggregate values including credits and upstream emissions for which only CO_2E values are available. Individual GHG constituent values will not correspond directly with the reported total global warming potential.

Table H-3: Summary of emissions and resource demands for 1.5 HCPV CO_2 WAG EOR scenario.

Parameter	Units	Site Eval. & Char.	Construction	Operation	Closure	MVA	Total
Greenhouse Gas Emissions							
CO_2	kg/bbl crude	1.97E-03	3.45E-01	9.09E+01	9.72E-02	3.93E-03	9.13E+01
CH_4	kg/bbl crude	0.00E+00	7.50E-05	1.41E-01	9.93E-07	0.00E+00	1.41E-01
N_2O	kg/bbl crude	0.00E+00	0.00E+00	2.54E-04	0.00E+00	0.00E+00	2.54E-04
SF_6	kg/bbl crude	0.00E+00	0.00E+00	2.15E-11	0.00E+00	0.00E+00	2.15E-11
CO_2E*	kg/bbl crude	2.07E-03	3.61E-01	9.42E+01	1.01E-01	4.13E-03	9.46E+01
Criteria Air Pollutants							
NO_X	kg/bbl crude	9.04E-06	1.49E-03	3.53E-02	4.22E-04	1.81E-05	3.72E-02
CO	kg/bbl crude	4.81E-06	8.12E-04	1.01E-01	2.17E-04	9.62E-06	1.02E-01
PM (Total)	kg/bbl crude	2.30E-07	3.71E-03	1.53E-03	6.49E-05	4.60E-07	5.30E-03
Lead	kg/bbl crude	0.00E+00	0.00E+00	5.86E-07	0.00E+00	0.00E+00	5.86E-07
SO_2	kg/bbl crude	1.74E-10	6.92E-04	1.02E-01	5.06E-05	3.47E-10	1.03E-01
VOC	kg/bbl crude	6.05E-07	9.02E-05	1.83E-01	2.62E-05	1.21E-06	1.84E-01
Water Use							
Fresh water consumption	kg/bbl crude	0.00E+00	5.01E-03	2.41E-01	5.14E-04	0.00E+00	2.47E-01
Excess Brine for Injection Disposal	barrel excess brine per bbl crude	-	-	6.65E-01	-	-	6.65E-01
CO_2 Sequestered (gross)							
Injected - produced	kg/bbl crude	-	-	211	-	-	211
Land Use							
Total Pattern Coverage	Acres/bbl crude	-	-	1.17E-04	-	-	1.17E-04

* CO_2 equivalent values are aggregate values including credits and upstream emissions for which only CO_2E values are available. Individual GHG constituent values will not correspond directly with the reported total global warming potential.