HEAVY OIL RESERVOIRS RECOVERABLE
BY THERMAL TECHNOLOGY
VOLUME I

ANNUAL REPORT

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1. INTRODUCTION

The purpose of this study was to compile data on reservoirs that contain heavy oil in the 8 - 25° API gravity range, contain at least ten million barrels of oil currently in place, and are non-carbonate in lithology. The reservoirs within these constraints were then analyzed in light of applicable recovery technology, either steam-drive or *in situ* combustion, and then ranked hierarchically as candidate reservoirs.

The study is presented in three volumes. Volume I presents the project background and approach, the screening analysis, ranking criteria, and listing of candidate reservoirs. The economic and environmental aspects of heavy oil recovery are included in appendices to this volume.

Volume II presents the data for reservoirs susceptible to steam-drive, less than 2500 feet deep, and *in situ* combustion. Volume III presents the data on reservoirs potentially recoverable by steam drive, but equal to or greater than 2500 feet deep. Both of these volumes also contain a complete listing of operators and projects, as well as a bibliography of source material.

1.1 BACKGROUND

In the 1970's, a steadily increasing crude oil demand was accompanied by a steady decline in domestic production. Currently, more than 50 percent of crude oil supplies needed to meet United States demand are imported. This large (nine million B/D) and growing dependence on foreign oil indicates economic sensitivity to OPEC actions that can only be mitigated by increased domestic production and conservation.

There are currently close to 300 billion barrels of domestic crude oil resources. However, present technology will enable the ultimate

recovery of only about ten percent of this total. This leaves approximately 270 billion barrels of known crude oil resources that cannot be recovered by conventionally applied methods.

Enhanced oil recovery techniques are developing technologies aimed at increasing crude oil recovery through the application of heat or chemicals to the reservoir. It has been estimated that these technologies have the potential of freeing up to 50 billion additional barrels of crude oil for ultimate recovery.

This project examines the potential of thermal EOR operations for reservoirs of non-carbonate lithology with heavy crude oil between 8 - 25° API gravity. Such oil is very viscous and typically high in sulfur and metal content. Because of these characteristics, heavy oil is both hard and expensive to recover and transport and when refined, generates a much less "valuable" product slate than light crude oil. The world energy crisis and spiralling crude oil prices have made the economics of production and recovery of heavy oil increasingly attractive.

The U.S. heavy oil resource base has been estimated by DOE, USGS, and API at greater than 100 billion barrels. Disagreement surfaces in estimates of heavy oil reserves. Dr. Joseph Barnea, former Director of Natural Resources at the United Nations states: "It is hard to estimate total reserves for the United States because there has never been a systematic search for heavy oil. Nearly all the heavy oil we know about in the U.S. has been discovered by accident - in the course of exploring for light oil." President Carter, in a fact sheet on heavy oil released August 17, 1979, stated the reserves of heavy oil at 10 billion barrels. Other credible estimates, however, indicate that approximately 12 billion barrels of heavy oil can be recovered just from onshore California reservoirs (Mark Henwood, EAD - 11A 4:01, 1978). Most of the heavy oil reserves are located in California, but additional reserves are found in such states as Texas, Louisiana, Oklahoma, Mississippi, and Wyoming.

Since in the past there was little incentive to produce heavy oil, this resource has not been sufficiently explored and characterized. Many experts agree, however, that heavy oil reserves are enormous. Former Deputy Energy Secretary, John O'Leary, has stated that heavy oil could make the United States "totally independent of Mid-East oil in twenty years".

Given these considerations, the present study was initiated with the following objectives in mind:

- To prepare a comprehensive and updated listing of those heavy oil reservoirs amenable to thermal EOR methods which:
 - Are within the gravity range of 8 - 25° API
 - Are in non-carbonate formations
 - Are onshore
 - Contain a minimum of 10 million barrels of oil-in-place
- To delineate and rank identified candidate reservoirs on the basis of the most appropriate thermal recovery technique with distinction as to depth
- To compile and document all data used and evaluate its reliability
- To determine the current ownership of these reservoirs and develop a list of operators and past or current projects
- To define the economic and environmental aspects involved in the application of thermal EOR methods.

1.2 APPROACH

Starting with SAI's initial data base on heavy oil resources, prepared for DOE's Bartlesville Energy Technology Center, and the Petroleum Data System (PDS) developed by the University of Tulsa, all published heavy oil information was collected and reviewed. Many of these various data sources had to be correlated in order to evaluate reservoir extent and characteristics, geologic and geophysical data, fluid properties, production figures, etc. National and state oil and gas statistics were

collected from the relevant authorities and available data were recorded. Emphasis was placed on acquiring reservoir and production data from several sources in order to obtain the most reliable figures. Wherever possible, operators' data were obtained.

The candidate reservoir data sources were placed in three categories with respect to closeness to the origin of the data. The first category of sources includes those whose data came directly from the origin, such as: 1) direct operator response to requests for information to be incorporated into the reservoir data base for this project; 2) U.S. Bureau of Mines report on crude oil analyses; 3) publications authored or co-authored by operator personnel regarding specific reservoirs and their characteristics; and 4) state hearing reports which include specific reservoir data supplied by the operator(s).

The second category of sources includes those which receive and print their data from the first category type sources. These specifically include such sources as: 1) individual state agency publications reviewing facets of oil and gas operations in their respective states, e.g., annual production statistics, secondary and enhanced recovery project operations and reviews, etc; 2) industry and professional journal articles and other publications drawing on specific reservoir data but not authored by the operating companies; and 3) private petroleum industry service companies which gather and publish oil field and reservoir data such as Petroleum Information, Inc. and the International Oil Scouts Association.

The third category of sources encompasses all other source material. This includes such sources as PDS, Lewin & Associates, USBM/IC 8263 and 8428, and other survey type data publications with multiple references.

Upon categorizing the data, a comprehensive and computerized Data Base Management System with the associated data files and other software was then developed, and all relevant information was recorded on a master tape. By a process of elimination, the original large list of known heavy oil reservoirs was narrowed down to meet the study criteria.

The next step consisted of detailed review and analysis of published results on all completed or ongoing thermal recovery projects. This was used to develop screening criteria which could be used to select candidate reservoirs.

Simultaneously, a comprehensive list of present owners and operators of potential candidate reservoirs was prepared by searching out various state records and files.

Environmental constraints to heavy oil recovery processes were studied and applicable state or local regulations were compiled.

Existing and potential economic incentives, which might expedite widespread commercial application of thermal recovery processes, were analyzed and evaluated on a generic basis.

In the final stages of the project, the remaining candidate reservoirs were ranked and prioritized in conformance with the contract requirements.

2. RESERVOIR SCREENING

Approximately 2500 reservoirs in the 8 - 25° API range were screened down to 247 candidate reservoirs containing at least 10 million barrels of oil-in-place according to the following procedures.

2.1 METHODOLOGY OF CANDIDATE RESERVOIR SELECTION

To arrive at a list of onshore, non-carbonate heavy oil reservoirs containing at present at least 10 million barrels of crude oil within an 8 - 25° API gravity range, it was necessary to create a list of all heavy oil reservoirs from various sources. These sources included SAI's own heavy oil data base, The Petroleum Data System, International Oil and Gas Development, 1976, by the International Oil Scouts Association, the various state oil and gas production publications, and the U.S. Bureau of Mines Information Circulars 8263 and 8428. From this list, those reservoirs were eliminated that are predominantly carbonate in composition, offshore, or contain crude oil outside of the 8 - 25° API gravity range. At this point, the search and gathering of additional, more detailed information was begun. This was to determine if a reservoir contained over 10 million barrels of oil-in-place, to further characterize and describe the reservoir, and to describe secondary and enhanced oil recovery operations undertaken in it.

All pertinent state agencies such as oil and gas commissions, state corporation commissions, state geological surveys, and some state universities were contacted to get state publications and leads on additional information sources not available through the mail or information gathering visits to state agency offices. Additionally, professional journals and Federal Government publications were collected containing information regarding thermal EOR projects in specific reservoirs for use both in developing a current set of screening criteria and to get more detailed data.

Using this information, a first cut of potential candidate reservoirs was made based on the likelihood that a reservoir in question contained, at present, over 10 million barrels of oil. In some cases, this was determined from a combination of factors such as the number of producing wells, length of time under production, cumulative production, areal extent, and thickness. These reservoirs were retained in the possible candidate file when the information already obtained indicated that particular reservoirs may possibly have at least 10 million barrels of oil remaining in-place or that the information given was mainly fieldwide in scope and not reservoir-specific, thereby masking the true size and character of a particular reservoir containing heavy oil.

The list of possible and definite candidate reservoirs was used to direct the retrieval of additional reservoir information. This involved visits to state agencies to extract all pertinent nonproprietary information from their respective files involving specific reservoirs. This information was usually in the form of hearing reports and supporting data sheets submitted by the operators for state hearings regarding specific reservoirs. Also, operators were contacted directly to request data for reservoirs which they wholly or partly operate. The responses that were received proved invaluable, as the information was clear, concise, and reservoir-specific.

As used herein, the term, reservoir, was taken to mean a specific producing interval of a particular geologic formation or combination of formations that are segregated enough from other producing zones, either laterally or vertically, to be identified by the operators as a separate producing entity. In this study, the existence of zonation within a reservoir due to thin, tight streaks or shale laminae was a common occurrence, as was the existence of varying degrees of faulting. The identification and extent of specific reservoirs was based on information supplied by the operators, as they are the authority on the development and character of a particular producing entity. Only under two types of

circumstances were reservoirs disqualified for geological reasons related to separation of parts of a reservoir. The first was extreme stratigraphic variation within a reservoir, which upon study of cross-sections and maps indicated that producing portions were so numerous and separated, generally due to sands lensing with shale, that no particular zone within the reservoir could have 10 million barrels of oil-in-place. In these cases, the overall resource from all of the zones in the reservoir was not considered large enough for the reservoir to be considered as a bona fide candidate reservoir. The second reason for disqualification was due to extreme faulting within a reservoir. This was felt justifiable since, upon study of cross-sections, maps, and geologic reports, certain reservoirs were found to be made up of many small fault blocks within discontinuous producing capability vertically and horizontally due to the faulted character of the reservoir. This was the case in certain reservoirs associated with salt dome structures around the Gulf Coast and a few extremely faulted reservoirs in California.

All of the available reservoir information was transferred to the individual reservoir data sheets at which time they were reevaluated to estimate volumetrically their remaining crude oil resource. Those with less than 10 million barrels of oil remaining in-place and those whose areal extent was determined to be less than 40 acres were eliminated. At this point, there were still reservoirs whose areal extent and production data were masked by the availability of only fieldwide data, thus preventing proper evaluation. This was the case for several reservoirs in fields in Oklahoma, Louisiana, Wyoming, and Kansas where state-supplied information such as production and/or acreage was given only for whole fields although included reservoirs were listed. The fields in question involve those with more than one reservoir where some or all of the other reservoirs do not contain oil of less than 25° API gravity. To at least roughly estimate the size of these masked reservoirs, it was necessary through the use of some state publications and the Petroleum

Information Service to determine the number of producing wells in that particular reservoir and the well spacing that was prescribed. In this way, many reservoirs which were at first questionable as to resource-in-place were shown to have definitely more than 10 million barrels of oil in-place even though some data were still lacking which could afford a more accurate resource estimation. In these cases, either the original and remaining resource is not estimated or the calculations made are labeled as having been derived from estimated parameters.

2.2 *IN SITU* COMBUSTION SCREENING GUIDE

There are several screening guides in literature; those by Poettman, Geffen, and Simm are usually cited. Lewin and Gurc put forward their own screening guide in connection with their involvement with thermal recovery studies. The tools available for developing the screening criteria are usually actual field test results. The assumption is that the operator must have given thorough technical and economic consideration in selecting the reservoir for fireflood, among other alternatives, is indeed a valid assumption. With sufficiently large test population, the effect of characterizing parameters can be gauged independently, or in some dependent fashion on test outcome which is usually success or failure, or merely reservoir selection. The characterizing parameters must again be those which are or can be readily made available by the user.

In developing the screening guide, or testing the validity of other guides, the following approach was used. The literature for all *in situ* combustion field tests was compiled from the Journal of Petroleum Technology/Society of Petroleum Engineers, Oil & Gas Journal, EOR symposiums, etc. Each paper was briefly reviewed for the characterizing parameters, not only for reservoirs, but for geology, laboratory investigations, production performance, and process as well. A tableau was prepared consisting of the total parameters identified. All the papers were

thoroughly reviewed again to complete the tableau. The effect of each parameter was gauged independently in the form of probability distribution curves with regard to total projects, successful ones, failures, or unrated. No distinction was made between dry and wet combustion projects, but the effect of the combustion process parameter was evaluated separately like any other parameter. Two critical ISC project reviews were made: the first one a more general, underlining influence of each parameter; and the second one a more specific, underlining highlights of each project. The screening criterion was developed based on critical parameters, i.e., parameters with adequate sample size showing definitive trends in the distribution curve. The resulting screening guide is as follows:

Depth (ft)	Not critical (<4500 favorable)
Net thickness (ft)	> 10. (10-60 favorable)
Porosity (%)	> 20
Permeability (md)	> 100 (450-1300 favorable)
API Gravity (deg)	12-25
Viscosity (cp)	60-1000
So (%)	> 50
Sg (%)	< 10
ϕ So (fraction)	> 0.13 (1000 B/AF)
Gas cap	None
Lithology	Non-carbonate

The screening guide appears to be a composite of other guides. It recognizes the reservoir thickness constraint. Depth is somewhat relaxed compared to Poettman. The porosity lower limit corresponds to Poettman and Chu. Permeability constraint agrees with Poettman and Simm. The API gravity, viscosity, oil saturation, and ϕ So (porosity times oil saturation) constraints agree with Chu's guide. The criterion closely agrees with Chu with some constraints pointed out by Poettman, Simm, and Geffen. Chu's approach was quantitative and the critical parameters were evaluated using a confidence limits approach.

2.3 STEAM-DRIVE SCREENING GUIDE

There are several screening guides in the literature, but one by Farouq Ali has been the most often quoted. The approach used for developing a steam-drive screening guide for the purpose of this project was the same as for *in situ* combustion. A number of articles were thoroughly reviewed on steam-drive projects, and a grand tableau was prepared containing all possible reservoir and production performance information. Probability distribution curves were plotted for each of the parameters in the tableau depicting the influence of the parameters on reservoir selection as well as project success. Two critical reviews were made, the general one based on each characterizing parameter, and the specific one pointing out the highlights of each project. The steam-drive projects considered in this study may be limited somewhat in number, but not more than two projects were considered for a field unless the steam-drive process was distinct. The screening criteria that was arrived at for this study, based on critical parameters, is as follows:

Depth (ft)	< 2500
Net Thickness (ft)	> 30
Porosity (%)	> 20
Permeability (md)	> 1000
API Gravity (Deg)	12-25
Viscosity (cp)	100-6000
B/AF	> 500
Lithology	Non-carbonate

The screening guide is not too different from the one proposed by Farouq Ali. The guide is based on the total distribution of reservoirs targeted for steam drive, as few of the projects reflected technological constraints (failures).

3. RESERVOIR RANKING

Every reservoir that survived the final screening was ranked on a state-by-state basis in a hierarchical order. This was done in each category of technology, i.e., (1) steam drive less than 2500 feet deep, (2) steam drive greater than 2500 feet deep, and (3) *in situ* combustion. The final rank was determined mathematically.

3.1 STEAM-DRIVE RANKING EQUATION

The equation developed for ranking of the steam-drive reservoirs was based on considerations developed from a statistical review of projects contained in the literature, and a generic analysis of the modeling approaches developed at Stanford University, Shell Oil (Myhill and Stegemeier), and the University of Southern California (Doscher and Ershaghi).

The equation used is as follows:

$$Y = Z\phi\left[\frac{h_n}{h_t}\right] (S_o - 0.20) T_r$$

Y = ranking parameter
Z = depth, feet
 ϕ = porosity, fraction
 h_n = net thickness, feet
 h_t = gross thickness, feet
 S_o = current oil saturation, fraction
 T_r = transmissivity = kh_n/μ
k = permeability, md
 μ = viscosity, cp

The ranking parameter (Y) was calculated for all reservoirs where there was a complete data set, as reported in Volume II and Volume III of this study. This group was given higher target priority than the second group wherein Y was calculated using estimates for missing data. Missing data were estimated, where needed, as follows:

- Permeability (k) - the geometric mean of the data available for the state was used.
- Current Oil Saturation (S_o) - the arithmetic average for S_o of the same state was used.
- Gross or Net Thickness (h_n , h_t) - $h_n = 0.6 h_t$ (rule of thumb)
- Viscosity (μ) - a regression analysis was executed on the given data, which resulted in the following equation used to estimate viscosity:

$$\mu = A (\text{API}^\circ * \text{DEPTH})^{-B}, \text{ where}$$

$$A = 6.749 \times 10^{13}$$

$$B = 2.563$$

3.2 IN SITU COMBUSTION RANKING EQUATION

The equation used for the ranking of *in situ* combustion reservoirs was that developed by C. Chu ("A Study of Fireflood Field Projects," JPT, February 1977, 111), as follows:

$$Y = A + B*Z + C*\phi + D*k + E*(kh/\mu)$$

$$+ F*\phi S_o, \text{ where}$$

$$A = 2.257$$

$$B = 0.0001206$$

$$C = 5.704$$

$$D = 0.0001040$$

$$E = -0.00007834$$

$$F = 4.600$$

$$Z = \text{depth, feet}$$

$$\phi = \text{porosity, fraction}$$

$$k = \text{permeability, md}$$

$$h = \text{thickness, feet}$$

$$\mu = \text{viscosity, cp}$$

$$S_o = \text{current oil saturation}$$

Two groups were again ranked, one with complete data sets, and the other with estimated data. Missing data were estimated in the same manner as for steam drive.

3.3 RANK LISTING

The reservoirs are ranked on a state-by-state basis in two groups for each technology type. The first priority group contains those reservoirs with a complete data set as reported in Volumes II and III. The second priority group contains reservoirs whose data set was incomplete, but estimable for ranking purposes. The reservoirs are listed in the following tables. The most satisfactory reservoir is placed at the top of the listing and the least satisfactory at the bottom.

Professionals involved in the technology might find discrepancies in the ranking. For instance, the Kern River field and Midway Sunset field in California are low ranked. However, they have been extensively produced by steam drive and should logically be high ranked. The rationale for their position is based on the available data being plugged into the ranking equation. This equation is a first cut approximation; it being extremely difficult to develop a truly generalized equation at the executed level of effort. Also, the equation does not consider economic factors which clearly change the ranking results.

It is recommended that the ranking be used as a preliminary guide, establishing the basis for a more detailed perusal of the data presented in Volumes II and III. This data can be analyzed and compared in a variety of ways, as well as feed into "in-house" decision models. Interested parties, by using such a procedure, can zero in on a small number of prospects. This will greatly simplify the acquisition of the extremely detailed information required for investment and production decisions. To further facilitate such activity, Volumes II and III also contain listings of operators and projects.

The rank listing for steam drive contains 124 reservoirs and for *in situ* combustion contains 154 reservoirs. This is a larger set than the total 247 candidate reservoirs because the subset, which can be either steam drive or *in situ* combustion, is ranked and reported in both places.

TABLE 3.1.a. Ranking for Reservoirs Less than 2500 Feet Deep Recoverable
By Steam-Drive Technology, Using Reported Data

CALIFORNIA				
Case	County	District	Field	Reservoir
174	Kern	San Joaquin Valley Region	Mount Poso	Mount Poso Area Vedder
30	Los Angeles	Coastal Region Santa Clara Valley	Placerita	All Areas
14	Monterey	Coastal Region Salinas Valley	San Ardo	Aurignac
91	Los Angeles	L.A. Region	Wilmington	East Area Fault Block V Tar
69	Los Angeles	L.A. Region	Inglewood	Vickers
152	Kern	San Joaquin Valley Region	Lost Hills	Main
99	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block IV Tar
115	Los Angeles	L.A. Region	Wilmington	Terminal Area Fault Block III Tar
102	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block V Tar
15	Monterey	Coastal Region Salinas Valley	San Ardo	Lombardi
166	Kern	San Joaquin Valley Region	Midway- Sunset	Others
154	Kern	San Joaquin Valley Region	McKittrick	Main Area Upper
149	Fresno & Kern	San Joaquin Valley Region	Kern Front	Main

TABLE 3.1.a. Ranking for Reservoirs Less than 2500 Feet Deep Recoverable
By Steam-Drive Technology, Using Reported Data
(Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
142	Kern	San Joaquin Valley Region	Edison	Main Area Upper
150	Fresno & Kern	San Joaquin Valley Region	Kern River	Pliocene - Kern River
120	Orange	L.A. Region	Yorba Linda	Main (Smith)
132	Kern	San Joaquin Valley Region	Belridge, South	Tulare - Etchegoin - Diatomite
171	Kern	San Joaquin Valley Region	Midway-Sunset	Spellacy 200 Sand
140	Kern	San Joaquin Valley Region	Cymric	Wellport Area Tulare
LOUISIANA				
211	Iberville	Southeast	White Castle	WC V RD SU & U RD SU
WYOMING				
297	Natrona		Casper Creek, South	Tensleep
327	Fremont		Winkelman Dome	Nugget

TABLE 3.1.b. Ranking for Reservoirs Less than 2500 Feet Deep Recoverable
By Steam-Drive Technology, Using Estimated Data

ARKANSAS				
Case	County	District	Field	Reservoir
9	Ouachita & Union		Smackover (Old)	Nacatoch
4	Nevada		Irma	Old Nacatoch
CALIFORNIA				
177	Kern	San Joaquin Valley Region	Poso Creek	Enas Area
138	Kern	San Joaquin Valley Region	Cymric	Sheep Springs Area 54-21 Etchegoin
86	Los Angeles	L.A. Region	Whittier	Rideout Heights (New Plio, Old)
137	Kern	San Joaquin Valley Region	Cymric	Salt Creek Main Area Carneros Unit
70	Orange	L.A. Region	Kraemer	Kraemer
179	Kern	San Joaquin Valley Region	Poso Creek	Premier Area Main
127	Kern	San Joaquin Valley Region	Antelope Hills	Williams Area East Block Agua
128	Kern	San Joaquin Valley Region	Antelope Hills	Williams Area East Block Button Bed
184	Kern	San Joaquin Valley Region	Round Mountain	Round Mountain Area Vedder
12	Monterey	Coastal Region Salinas Valley	King City	Miocene
135	Kern	San Joaquin Valley Region	Cymric	McKittrick Front Area Reef Ridge

TABLE 3.1.b. Ranking for Reservoirs Less than 2500 Feet Deep Recoverable
By Steam-Drive Technology, Using Estimated Data
(Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
32	Ventura	Coastal Region Santa Clara Valley	Tapo Canyon South	4th Sespe
190	Kern	San Joaquin Valley Region	Wheeler Ridge	Central Area Coal Oil Canyon
193	Kern	San Joaquin Valley Region, Other Fields	White Wolf	
68	Orange	L.A. Region	Huntington Beach	South Area Onshore Tar Zone
122	Orange	L.A. Region	Yorba Linda	Shell
125	Riverside	L.A. Region, Other Fields	Prado- Corona	Sardco Area- Hunter
129	Kern	San Joaquin Valley Region	Antelope Hills	Williams Area W.B. Button Bed-Agua
33	Los Angeles	Coastal Region Santa Clara Valley	Wayside Canyon	Pliocene
75	Orange	L.A. Region	Newport West	Main Area
124	Riverside	L.A. Region, Other Fields	Prado- Corona	Goedhart Area- Hunter
24	Los Angeles	Coastal Region Santa Clara Valley	Newhall Gr. - Tunnel Area	Unnamed
110	Los Angeles	L.A. Region	Wilmington	Terminal Area Fault Block II-A Tar

TABLE 3.1.b. Ranking for Reservoirs Less than 2500 Feet Deep Recoverable
By Steam-Drive Technology, Using Estimated Data
(Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
165	Kern	San Joaquin Valley Region	Midway-Sunset	Olig
172	Kern	San Joaquin Valley Region	Mount Poso	Dominion Area - Vedder
185	Kern	San Joaquin Valley Region	Round Mountain	Round Mountain-Jewett & Pyramid Hill
183	Kern	San Joaquin Valley Region	Round Mountain	Coffee Canyon-Vedder & Pyramid Hill
25	Ventura	Coastal Region Santa Clara Valley	Oak Park	Sespe Upper
21	Santa Barbara	Coastal Region Santa Barbara	Capitan	Vaqueros
126	Kern	San Joaquin Valley Region	Ant Hill	Olcese
26	Ventura	Coastal Region Santa Clara Valley	Oakridge	Miocene
180	Kern	San Joaquin Valley Region	Pyramid Gr-Blackwells Corner	Temblor & Agua
148	Fresno & Kern	San Joaquin Valley Region	Kern Bluff	Miocene
178	Kern	San Joaquin Valley Region	Poso Creek	McVan Area
130	Kern	San Joaquin Valley Region	Antelope Hills, North	Miocene

TABLE 3.1.b. Ranking for Reservoirs Less than 2500 Feet Deep Recoverable
By Steam-Drive Technology, Using Estimated Data
(Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
123	Los Angeles	L.A. Region, Other Fields	Los Angeles City	Miocene Zones 1-2-3
136	Kern	San Joaquin Valley Region	Cymric	McKittrick Front Area Tulare
121	Orange	L.A. Region	Yorba Linda	Shallow
27	Ventura	Coastal Region Santa Clara Valley	Ojai GR- Sisar Area	Unnamed
134	Fresno	San Joaquin Valley Region	Coalinga Gr -Coalinga	West Side Area Temblor
131	Kern	San Joaquin Valley Region	Belridge, North	Shallow
KANSAS				
198	Woodson	Eastern Stripper	Big Sandy Pool	Bartlesville
201	Woodson	Eastern Stripper	Own Creek	Squirrel
LOUISIANA				
213	Calcasieu	Southwest	Vinton	Upper Miocene
203	Bossier & Webster	North	Bellevue	Nacatoch
204	Caddo	North	Caddo Pine Island	Nacatoch
OKLAHOMA				
236	Carter	South Central	Sho-Vel-Tum	Pontotoc (Oil City Unit)
235	Carter	South Central	Sho-Vel-Tum	4th Deese (Des Moines or Penn Sand)

TABLE 3.1.b. Ranking for Reservoirs Less than 2500 Feet Deep Recoverable
By Steam-Drive Technology, Using Estimated Data
(Continued)

OKLAHOMA (Continued)				
Case	County	District	Field	Reservoir
237	Stephens	Southwest	Loco	Loco Sands
TEXAS				
257	Washington	Three	Clay Creek	Sparta-Queen City-Wilcox
244	Medina	One	Taylor Ina	Navarro Reservoir
WYOMING				
326	Johnson		Tisdale, North	Curtis

TABLE 3.2.a. Ranking for Reservoirs Equal to or Greater than 2500 Feet Deep Recoverable by Steam-Drive Technology, Using Reported Data

CALIFORNIA				
Case	County	District	Field	Reservoir
73	Los Angeles	L.A. Region	Montebello	Main Area - Baldwin 1-2-3
90	Los Angeles	L.A. Region	Wilmington	East Area Fault Block 90-S Terminal
88	Los Angeles	L.A. Region	Wilmington	East Area Fault Block 90-N Terminal
96	Los Angeles	L.A. Region	Wilmington	East Area Fault Block VIII-A Terminal
93	Los Angeles	L.A. Region	Wilmington	East Area Fault Block VI Upper Terminal
87	Los Angeles	L.A. Region	Wilmington	East Area Fault Block 90-N Ranger
89	Los Angeles	L.A. Region	Wilmington	East Area Fault Block 90-S Ranger
97	Los Angeles	L.A. Region	Wilmington	East Area Fault Block VIII-B Ranger
95	Los Angeles	L.A. Region	Wilmington	East Area Fault Block VIII-A Ranger
57	Orange	L.A. Region	Coyote East	Anaheim
103	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block V-A Upper Term
94	Los Angeles	L.A. Region	Wilmington	East Area Fault Block VII Ranger
92	Los Angeles	L.A. Region	Wilmington	East Area Fault Block VI Ranger
111	Los Angeles	L.A. Region	Wilmington	Terminal Area Fault Block II-A Upper
54	Los Angeles & Orange	L.A. Region	Brea-Olinda	Brea Area and Others
100	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block IV Upper Term

TABLE 3.2.a. Ranking for Reservoirs Equal to or Greater than 2500 Feet Deep
Recoverable by Steam-Drive Technology, Using Reported Data
(Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
55	Los Angeles & Orange	L.A. Region	Brea-Olinda	Olinda Area
64	Orange	L.A. Region	Huntington Beach	North Area Tar Bolsa
104	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block V-B Upper Term
113	Los Angeles	L.A. Region	Wilmington	Terminal Area Fault Block II-B Upper
108	Los Angeles	L.A. Region	Wilmington	Terminal Area F.B. I Tar-Ranger Terminal
114	Los Angeles	L.A. Region	Wilmington	Terminal Area Fault Block III Ranger
83	Los Angeles	L.A. Region	Torrance	Del Amo
107	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block VI Upper Terminal
147	Kern	San Joaquin Valley Region	Fruitvale	Main Area Chanac- Kernco
37	Santa Barbara	Coastal Region, Santa Maria	Cat Canyon East	Sisquoc Area, Others
101	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block V Ranger
98	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block IV Ranger
118	Los Angeles	L.A. Region	Wilmington	Town Lot Area Fault Block II-A Upper
117	Los Angeles	L.A. Region	Wilmington	Town Lot Area Fault Block II-A Ranger

TABLE 3.2.a. Ranking for Reservoirs Equal to or Greater than 2500 Feet Deep Recoverable by Steam-Drive Technology, Using Reported Data (Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
119	Los Angeles	L.A. Region	Wilmington	Town Lot Area Fault Block III Ranger
116	Los Angeles	L.A. Region	Wilmington	Town Lot Area F.B. I Tar-Ranger Terminal
106	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block VI Ranger
109	Los Angeles	L.A. Region	Wilmington	Terminal Area Fault Block II-A Ranger
112	Los Angeles	L.A. Region	Wilmington	Terminal Area Fault Block II-B Ranger
105	Los Angeles	L.A. Region	Wilmington	Harbor Area Fault Block VI Lower Terminal
84	Los Angeles	L.A. Region	Torrance	Main
39	Santa Barbara	Coastal Region	Cat Canyon West	Los Flores
133	Fresno	San Joaquin Valley Region	Coalinga Gr - Coalinga	East Side Temblor
OKLAHOMA				
240	Stephens	Southwest	Sho-Vel-Tum	Tussy
TEXAS				
285	Wood	Six	Hawkins	Woodbine
289	Titus	Six	Talco	Paluxy
260	Fort Bend	Three	Thompson, South	4400 Sand (Miocene Y)

TABLE 3.2.a. Ranking for Reservoirs Equal to or Greater than 2500 Feet Deep
Recoverable by Steam-Drive Technology, Using Reported Data
(Continued)

WYOMING				
Case	County	District	Field	Reservoir
328	Fremont		Winkleman Dome	Tensleep
295	Big Horn		Byron	Embar-Tensleep
306	Hot Springs		Byron	Embar-Tensleep
313	Park & Hot Springs		Little Buffalo Basin	Tensleep
309	Hot Springs		Hamilton Dome	Tensleep

TABLE 3.2.b. Ranking for Reservoirs Equal to or Greater than 2500 Feet
Deep Recoverable by Steam-Drive Technology, Using
Estimated Data

ARKANSAS				
Case	County	District	Field	Reservoir
6	Ouachita & Union		Smackover (Old)	Blossom
CALIFORNIA				
77	Los Angeles	L.A. Region	Playa Del Rey	Venice Area
79	Orange	L.A. Region	Richfield	West Area
67	Orange	L.A. Region	Huntington Beach	South Area Onshore Main
143	Kern	San Joaquin Valley Region	Edison	Portals - Fairfax Area Wicker Nozu
191	Kern	San Joaquin Valley Region	Wheeler Ridge	Windgap Area L-36 Reserve
186	Kern	San Joaquin Valley Region	Tejon Gr - Tejon Grapevine	Central Area Reserve
176	Kern	San Joaquin Valley Region	Pleito	Ranch Area
76	Los Angeles	L.A. Region	Playa Del Rey	Del Rey Hills Area
61	Los Angeles	L.A. Region	El Segundo	Main and West Areas
17	Los Angeles	Coastal Region San Fernando Valley	Aliso Canyon	Main Area Porter - Del Aliso - A-36
59	Orange	L.A. Region	Coyote East	Stern
38	Santa Barbara	Coastal Region Santa Maria	Cat Canyon West	Alexander
78	Orange	L.A. Region	Richfield	East Area

TABLE 3.2.b. Ranking for Reservoirs Equal to or Greater than 2500 Feet
Deep Recoverable by Steam-Drive Technology, Using
Estimated Data (Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
62	Orange	L.A. Region	Huntington Beach	Huntington Avenue Area Jones
44	Santa Barbara	Coastal Region Santa Maria	Lompoc	Monterey
160	Kern	San Joaquin Valley Region	Midway-Sunset	Lakeview
181	Kern	San Joaquin Valley Region	Rosedale Ranch	Chanac
19	Los Angeles	Coastal Region San Fernando Valley	Cascade	Pliocene (Cascade)
18	Los Angeles	Coastal Region San Fernando Valley	Aliso Canyon	Main Area Sesnon
31	Los Angeles & Ventura	Coastal Region Santa Clara Valley	Ramona	Kern-Del Valley
71	Los Angeles	L.A. Region	Long Beach	Northwest Extension Area - Brown
144	Kern	San Joaquin Valley Region	Edison	West Area Chanac Santa Margarita
139	Kern	San Joaquin Valley Region	Cymric	Sheep Springs Area Carneros
58	Orange	L.A. Region	Coyote East	Miocene "A"
36	Santa Barbara	Coastal Region Santa Maria	Cat Canyon East	Old Area

TABLE 3.2.b. Ranking for Reservoirs Equal to or Greater than 2500 Feet
Deep Recoverable by Steam-Drive Technology, Using
Estimated Data (Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
53	Los Angeles	L.A. Region	Beverly Hills	West Area Pliocene (Wolfskill)
16	Los Angeles	Coastal Region San Fernando Valley	Aliso Canyon	Main Area Aliso
169	Kern	San Joaquin Valley Region	Midway-Sunset	Republic
182	Kern	San Joaquin Valley Region	Rosedale Ranch	Lerdo
175	Kern	San Joaquin Valley Region	Pleito	Creek Area
85	Los Angeles	L.A. Region	Whittier	Main (Upper Zones)
45	Santa Barbara	Coastal Region Santa Maria	Orcutt	Main Area Monterey - Pt Sal
43	Santa Barbara	Coastal Region Santa Maria	Guadalupe	Sisquoc-Monterey
41	Santa Barbara	Coastal Region Santa Maria	Cat Canyon West	Pliocene (Old Area)
145	Kern	San Joaquin Valley Region	Elk Hills	Main Area Upper
40	Santa Barbara	Coastal Region Santa Maria	Cat Canyon West	Pliocene (New Area-Central)
189	Kern	San Joaquin Valley Region	Tejon Gr - Tejon Grapevine	Western Area S

TABLE 3.2.b. Ranking for Reservoirs Equal to or Greater than 2500 Feet
Deep Recoverable by Steam-Drive Technology, Using
Estimated Data (Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
48	Santa Barbara	Coastal Region Santa Maria	Santa Maria Valley	Main Area
56	Los Angeles & Orange	L.A. Region	Brea-Olinda	Tonner Area
MISSISSIPPI				
218	Perry		Glazier	Upper Tuscaloosa
214	Lamar & Marion		Baxterville	L. Tuscaloosa Massive
215	Lamar & Marion		Baxterville	Lower Tuscaloosa
220	Jasper		Heidelberg, East	Eutaw
216	Lamar & Marion		Baxterville -Southeast Fault	Lower Tuscaloosa
224	Jasper		Heidelberg, West	Eutaw
222	Jasper		Heidelberg, West	Christmas
231	Wayne		Yellow Creek, West	Eutaw
217	Wayne		Eucutta, East	Eutaw
221	Jasper		Heidelberg, East	Upper Tuscaloosa
229	Jones & Covington		Summerland	U Washita - Fredericksburg

TABLE 3.2.b. Ranking for Reservoirs Equal to or Greater than 2500 Feet
Deep Recoverable by Steam-Drive Technology, Using
Estimated Data (Continued)

OKLAHOMA				
Case	County	District	Field	Reservoir
234	Garvin	South Central	Pauls Valley	Oil Creek Sand
239	Stephens	Southwest	Sho-Vel-Tum	Sims C-1, C-2
TEXAS				
284	Wood	Six	Forest Hill	Harris Sand (B-F Segments)
253	Bee	Two	Papalote, East	3250 B
251	Refugio	Two	Lake Pasture	H-440 Sand
249	Jackson	Two	Ganado, West	4700 Zone
256	Jackson	Two	West Ranch	Greta Sand
WYOMING				
298	Johnson		Cellers Ranch	Tensleep
314	Johnson		North Fork	Tensleep
320	Campbell		Rocky Point	Minnelusa
307	Park		Half Moon	Embar-Tensleep
310	Washakie		Hidden Dome	Tensleep

TABLE 3.3.a. Ranking for Reservoirs Recoverable by *In Situ* Combustion Technology, Using Reported Data

Case	County	District	Field	Reservoir
ARKANSAS				
5	Union & Bradley		Lick Creek	Meakin
CALIFORNIA				
133	Fresno	San Joaquin Valley Region	Coalinga Gr - Coalinga	East Side Temblor
ILLINOIS				
197	Edgar		Dudley	Lower Dudley
OKLAHOMA				
240	Stephens	Southwest	Sho-Vel-Tum	Tussy
TEXAS				
288	Anderson	Six	Slocum	Carrizo Sand
291	Titus	Six	Trix-Liz	Woodbine D
275	Duval	Four	Lundell	Cole Sand
272	Jim Hogg	Four	Las Animas - LeFevre	Cole
290	Titus	Six	Trix-Liz	Woodbine B
263	Webb	Four	Aviators	Mirando Sand
289	Titus	Six	Talco	Paluxy
274	Webb	Four	Lopez	Mirando Sand
293	Pecos	Eight	Toborg	Toborg Sand
286	Titus	Six	Pewitt Ranch	Paluxy
273	Duval	Four	Loma Novia	Loma Novia Sand
268	Duval	Four	Government Wells, North	Lower Government Wells Sand
260	Fort Bend	Three	Thompson, South	4400 Sand (Miocene Y)

TABLE 3.3.a. Ranking for Reservoirs Recoverable by *In Situ* Combustion
Technology, Using Reported Data
(Continued)

Case	County	District	Field	Reservoir
TEXAS (Continued)				
277	Duval	Four	Piedre Lumbre	Government Wells Sand
243	Zauala	One	Little Tom	San Miguel A, A-1, C and D Sands
262	Brooks	Four	Alta Mesa	Garcia Sand
WYOMING				
305	Hot Springs		Grass Creek	Curtis

Table 3.3.b. Ranking for Reservoirs Recoverable by *In Situ* Combustion Technology, Using Estimated Data

ARKANSAS				
Case	County	District	Field	Reservoir
11	Nevada		Troy	Old Nacatoch
7	Ouachita & Union		Smackover (Old)	Graves
6	Ouachita & Union		Smackover (Old)	Blossom
10	Ouachita & Union		Smackover (Old)	Tokio
CALIFORNIA				
155	Kern	San Joaquin Valley Region	McKittrick	Northeast Area Upper
192	Kern	San Joaquin Valley Region, Other Fields	Jasmin	Cantleberry Vedder (2 Areas)
146	Fresno	San Joaquin Valley Region	Fresno Gr - Raisin City	Tar Miocene
173	Kern	San Joaquin Valley Region	Mount Poso	Dorsey Area - Vedder
41	Santa Barbara	Coastal Region, Santa Maria	Cat Canyon West	Pliocene (Old Area)
145	Kern	San Joaquin Valley Region	Elk Hills	Main Area Upper
40	Santa Barbara	Coastal Region, Santa Maria	Cat Canyon West	Pliocene (New Area - Central)
189	Kern	San Joaquin Valley Region	Tejon Grapevine	Western Area S
48	Santa Barbara	Coastal Region, Santa Maria	Santa Maria Valley	Main Area

Table 3.3.b. Ranking for Reservoirs Recoverable by *In Situ* Combustion Technology, Using Estimated Data
(Continued)

CALIFORNIA (Continued)				
Case	County	District	Field	Reservoir
56	Los Angeles & Orange	L.A. Region	Brea-Olinda	Tonner Area
KANSAS				
199	Allen	Eastern Stripper	Iola	Bartlesville
200	Allen	Eastern Stripper	Moran	Bartlesville
LOUISIANA				
207	LaSalle	North	Nebo-Hemphill	Cockfield
MISSISSIPPI				
227	Jones		Ovett	Eutaw
225	Clarke		Junction City	Eutaw
214	Lamar & Marion		Baxterville	L. Tuscaloosa Massive
215	Lamar & Marion		Baxterville	Lower Tuscaloosa
220	Jasper		Heidelberg, East	Eutaw
216	Lamar & Marion		Baxterville, Southeast Fault	Lower Tuscaloosa
226	Clarke		Langsdale	Eutaw
223	Jasper		Heidelberg, West	Cotton Valley
224	Jasper		Heidelberg, West	Eutaw

Table 3.3.b. Ranking for Reservoirs Recoverable by In Situ Combustion Technology, Using Estimated Data
(Continued)

MISSISSIPPI (Continued)				
Case	County	District	Field	Reservoir
222	Jasper		Heidelberg, West	Christmas
231	Wayne		Yellow Creek, West	Eutaw
228	Jones		Sandersville	Eutaw
217	Wayne		Eucutta, East	Eutaw
219	Jasper		Heidelberg, East	Christmas
230	Wayne		Yellow Creek, East	Eutaw
221	Jasper		Heidelberg, East	Upper Tuscaloosa
229	Jones & Covington		Summerland	U Washita - Fredericksberg
OKLAHOMA				
234	Garvin	South Central	Pauls Valley, Southeast	Oil Creek Sand
238	Stephens	Southwest	Sho-Vel-Tum	Humphrey
239	Stephens	Southwest	Sho-Vel-Tum	Sims C-1, C-2
TEXAS				
283	Anderson	Six	Camp Hill	Carrizo-Wilcox
265	Duval	Four	Cedro Hill	Cole Sand
284	Wood	Six	Forest Hill	Harris Sand (B-F Segments)

Table 3.3.b. Ranking for Reservoirs Recoverable by *In Situ* Combustion
Technology, Using Estimated Data
(Continued)

TEXAS (Continued)				
Case	County	District	Field	Reservoir
258	Harris	Three	Dyersdale	4000' Sand
276	Duval	Four	Lundell	Pettus
271	Zapata	Four	Jennings	Mirando & Mirando No. 1, South End
253	Bee	Two	Papalote, East	3250 B
247	Refugio	Two	Bonnie View	Bonnie View
269	Duval	Four	Government Wells, South	Government Wells
248	Victoria	Two	Coletto Creek	2800' Pool
266	Webb	Four	Cole, West	Mirando Sand
251	Refugio	Two	Lake Pasture	H-440 Sand
280	Duval	Four	Seven Sisters	Government Wells Sand
278	Hidalgo	Four	Sam Fordyce	San Fordyce Sand
249	Jackson	Two	Ganado, West	4700 Zone
279	Nueces	Four	Saxet	Oakville & Hetrogtegina
245	Atascosa	One	Weigang	Carrizo Sand
255	Refugio	Two	Tom O'Connor	4500 Greta Massive
246	Victoria	Two	Bloomington	4600
281	San Patricio	Four	Taft	4000' Sand

Table 3.3.b. Ranking for Reservoirs Recoverable by *In Situ* Combustion
Technology, Using Estimated Data
(Continued)

TEXAS (Continued)				
Case	County	District	Field	Reservoir
282	Hopkins	Five	Sulphur Bluff	Paluxy Pool
259	Wharton	Three	Magnet Withers	First Frio Pool
261	Fort Bend	Three	Thompson, South	Frio Pool
256	Jackson	Two	West Ranch	Greta Sand
WYOMING				
296	Campbell		Camp Creek	Minnelusa
312	Crook		Kummerfeld	Minnelusa (A & B Zones)
311	Campbell		Kuehne Ranch, Southeast	Minnelusa B
320	Campbell		Rocky Point	Minnelusa
325	Johnson		Tisdale, East	Tensleep
321	Big Horn & Park		Sage Creek	Tensleep
315	Natrona		Notches	Tensleep
307	Park		Half Moon	Embar-Tensleep
310	Washakie		Hidden Dome	Tensleep

4. CONCLUSIONS

A number of general and specific conclusions have resulted from this study. General conclusions are as follows:

- This study provides an extensive basis for heavy oil development, but should be extended to include carbonate reservoirs and tar sands.
- It is imperative to look at heavy oil reservoirs and projects on an individual basis; it was discovered that operators, and industrial and government analysts will lump heavy oil reservoirs as poor producers, however, it was found that upon detailed analysis, a large number, so categorized, were producing very well.
- A study should be conducted on abandoned reservoirs; it was found in the search that a number of abandoned reservoirs had as good a potential as some that were operating, but due to lack of data they were rejected from this project.
- To utilize heavy oil, refiners will have to add various unit operations to their processes, such as hydrotreaters and hydrodesulfurizers and will require, in most cases, a lighter blending stock.
- A big problem in producing heavy oil is that of regulation; specifically, it was found that the regulatory constraints are so fluid and changing that one cannot settle on a favorable recovery and production plan with enough confidence in the regulatory requirements to commit capital to the project.

Specifically, with respect to steam drive, it was found that:

- California contains most of the fields that are being recovered by steam drive.
- Major oil companies have played a principal role in steamflooding.
- Getty is operating the largest steamflood project.
- Steamfloods do not pose serious problems from the operations viewpoint.

- A typical project production performance which may be useful for design or evaluating economics is as follows:
 - Pattern Type..... 5-spot regular or inverted
 - Pattern Area..... 2.5 acres
 - Pilot Project Life..... Up to 5 years
 - Process Type..... Steam drive with supplemental steamsoak, if necessary
 - Steam Generator(s)..... 20 or 50 MMBtuH units based on project size
 - Steam Quality..... 70%
 - Injected Pressure..... 1000 to 2000 psig (Rated)
 - Injection Rate..... 500 to 1000 BPD/well
 - Fuel Requirements..... 25% of produced oil, if lease crude used
 - Oil-Steam Ratio..... 0.16 to 0.35 with 0.30 as optimum
 - Vertical Sweep..... 40 to 60%
 - Residual Oil..... 15% Saturation (Ave)
 - Operating Problems..... Casing failures could be serious, otherwise minor.

Specifically, with respect to *in situ* combustion, it was found that:

- Nacatoch sand reservoirs in Louisiana are favorable for ISC.
- Smaller fields in Texas, along the Gulf Coast, reacted somewhat favorably to ISC as a means of recovering additional oil.
- Though many firefloods were attempted in mid-continent Oklahoma/Kansas reservoirs, including Bartlesville sand formations, overall results were not encouraging.

- In the Rockies, especially Wyoming, with considerable heavy oil resources, only three ISC tests were conducted, only one in potentially heavy oil Tensleep formation and response was not favorable.
- There were fewer ISC projects in California, in comparison to its heavy oil resource, but they were successful, including a few fieldwide applications.
- Mobil Oil Co., amongst major producers, was more active in fireflood, and minor producers were on equal footing with the majors.
- Firefloods have been attempted on a variety of reservoirs, and in conjunction with water injection are effective as a tertiary recovery method in water-flooded light oil reservoirs.
- Operating problems influence the success of the projects more than any other variable.
 - Emulsions, corrosion, and sanding were the general problems, which in many cases were treatable.
 - Low injectivity was a severe problem.
 - In some cases, low productivity and unsuccessful stimulation led to failure.
- A typical project production performance which may be useful for design or evaluating economics is as follows:
 - Pattern Area (Pilot)..... 2.5 to 5 acres
 - Pilot Project Life..... 2 to 4 years
 - Injection Rate..... 1.5 MMCFD/inj. well
 - Injection Pressure..... 500 to 1500 psig
 - Process Type..... Dry (following water, if necessary)
 - Pattern Type..... Regular 5-spot or 9-spot
 - Fuel Consumption..... 200 to 250 BBL/AC-FT (av. 250)

- Primary Well Spacing..... 10 acres
- Air-Oil Ratio..... 10 to 20 MCF/BBL
- Air Requirement..... 10 to 12 MMCF/AC-FT
- Produced Combustion GOR..... 5 to 10 MCF/BBL (Av. 8)
- Combustion Efficiency..... > 90%
- Vertical Sweep..... 60%
- Volumetric Sweep..... 10 to 60%
- Recovery Factor..... 50 to 60%

Finally, the reservoirs reported in this document account only for about three billion barrels out of a projected ten to twelve billion barrels of heavy oil reserves, recoverable by current thermal techniques.

APPENDIX I:

ECONOMIC INCENTIVES AND CONSTRAINTS
FOR PRODUCTION AND UTILIZATION OF HEAVY OIL

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1. OVERVIEW

During most of the 1970's, regulatory factors and high costs resulted in major constraints to heavy oil production and utilization. However, since 1978 a series of government incentive programs and actions have greatly improved the current status and long-term prognosis of heavy oil production and technology development. The centerpiece of the government program is immediate price decontrol of heavy oil 20.0° API or less and the phased price decontrol of all crude oil production. Under the Administration's plan, all domestic crude oil price controls will end October 1, 1981. The entire portfolio of "incentives" is still being formulated, but the potential effects of the package on thermal EOR operations are most promising.

After briefly describing the series of economic constraints facing EOR production in the 1970's, the following sections will detail current and proposed incentives. The probable impacts of the incentive programs are assessed and incentives not implemented, but of potential value, are identified.

2. ECONOMIC CONSTRAINTS

Increased heavy oil utilization requires investment in EOR technologies. Throughout most of the 1970's, investment was hindered by a number of technical, regulatory, and economic uncertainties:

- Technical uncertainty has been associated with resource and recovery estimates.
- Economic uncertainty has been associated with both future production costs and market price.
- Regulatory uncertainty has been associated with increased investment risks and market unpredictability.

Exhibit 2-1 displays the matrix of production constraints that faced the heavy oil recovery technologies of steam drive and *in situ* combustion in January 1979.

**Exhibit 2-1. Summary of Production Constraints
January 1979**

<u>GENERAL (Applies to all Thermal Technologies)</u>	<u>STEAM DRIVE</u>	<u>IN SITU COMBUSTION</u>
<p>Uncertainty in Estimating Reservoir Structure and Saturation</p> <p>Uncertainty in Estimating Process Performance and Costs</p>	<p>The severity of this constraint greatly increases in areas outside of California.</p> <p>Increases investment risks - varies with region. Problems include:</p> <ul style="list-style-type: none"> • Low areal sweep efficiency. • Inability to maintain required steam heat at depths greater than 1500-2,000'. • Consumption of nearly one out of three barrels produced to serve as fuel to generate steam. 	<p>A salient constraint</p> <p>Level of uncertainty of costs and performance have greatly increased risks - risk adjusted ROI required probably close to 20%. Problems include:</p> <ul style="list-style-type: none"> • Frequent equipment failures, including casings. <p>Problems of abrasion, corrosion, emulsion, burnouts, and oxygen breakthrough. These difficulties in process control result in high and unpredictable operating costs:</p> <ul style="list-style-type: none"> • Frequently observed poor fuel/oil ratios. • Poor areal and vertical sweep
<p>Adherence to Price Control Regulations</p>	<p>Increases net costs, decreases prices. Makes projects, otherwise competitive, uneconomic. The most salient constraint to increased production</p>	<p>Same as Steam Drive</p>
<p>Adherence to Environmental Regulations</p>	<p>Greatly increases investment costs. Permitting processes create delays in operations increasing risk and time of payback.</p>	<p>Greatly increases investment costs and risks. Regulations inhibit further development of California projects in near term.</p>
<p>Operation In Mileu of Quickly Changing Price and Environmental Regulations</p>	<p>Projects require large investments put at substantial risk by this uncertainty. For example, DOE proposed regulations to place entitlement obligations on all lower tier crude used as fuel in steaming operations would substantially and negatively affect project economics.</p>	<p>Same as steam drive</p>
<p>High Front-End Production Costs: Delayed Payback.</p>	<p>An important constraint.</p>	<p>Same as steam drive</p>

Exhibit 2-1. Summary of Production Constraints
(Continued)

<u>GENERAL (Applies to all Thermal Technologies)</u>	<u>STEAM DRIVE</u>	<u>IN SITU COMBUSTION</u>
Unitization Laws	Not currently a significant factor in project evaluation.	Same as Steam Drive
Resource Unavailability	<ul style="list-style-type: none"> ● Water Use <ul style="list-style-type: none"> - Potential shortages of water - Logistic/economic problems in transportation of water - Water freeze-ups in cold weather environments 	Not a significant constraint.

3. INCENTIVES FOR HEAVY OIL PRODUCTION

Up through 1978, government incentives to overcome the constraints outlined in the previous sections included:

- (1) DOE cost-sharing programs,
- (2) Special entitlement subsidy to California refiners to decrease their costs for heavy crude oil acquisition, and
- (3) Price decontrol of new or incremental production from tertiary projects certified by DOE as "uneconomic" without price relief.

These programs provided some "relief" to heavy oil operators, but did little to improve the relative economics of thermal technologies. However, in 1979 the federal government introduced a series of incentives and removed many of the existing disincentives to heavy oil utilization. These incentive programs are described in the following sections.

3.1 THE PHASED PRICE DECONTROL OF DOMESTICALLY PRODUCED CRUDE OIL

On April 5, 1979, President Carter, using authority granted under the Emergency Petroleum Allocation Act (EPAA), announced a phased decontrol of domestic crude oil that commenced on June 1, 1979 with the price decontrol of all newly discovered domestic crude and ends with complete crude oil price decontrol on October 1, 1981. During this period, each field's ratio of old oil to new oil will gradually be decreased, freeing old oil to sell at new oil prices. The level of output classed as oil oil, known as a property's base period control level (BPCL), was reduced at 1 1/2 percent each month through the end of 1979 and increased to a 3 percent monthly reduction in January 1980. In addition, 80 percent of the old oil from marginal wells became eligible for upper tier prices in June 1979. The remaining 20 percent

of production from marginal wells was released to upper tier prices in January 1980. Marginal wells are defined as follows:

- Wells 2,000 to 4,000 feet deep with production less than or equal to 20 barrels per day,
- Wells 4,000 to 6,000 feet deep with production less than or equal to 25 barrels per day,
- Wells 6,000 to 8,000 feet deep with production less than or equal to 30 barrels per day, and
- Wells deeper than 8,000 feet with production less than or equal to 35 barrels per day.

Approximately 15 percent of total old oil qualified for upper tier prices in June 1979 as marginal well production. An equal monthly increase in the price of upper tier crude oil began in January 1980 (approximately 4.6 percent) and will end when all domestic oil production reaches the world market price on October 1, 1981.

3.2 HEAVY OIL PRICE DECONTROL

World market prices promise to substantially improve the economics of thermal oil production and technology development. To speed the production of heavy oil that will become economic at current world market prices, President Carter on December 21, 1979 issued Executive Order 12153 decontrolling domestic production of heavy oil 20.0° API or less. The Department of Energy has estimated that this order will increase daily production over 1979 levels by 450-550 MB/D by 1985.

Heavy oil decontrol ($\leq 20.0^\circ$ API) could have a very stimulative effect on thermal operations in California, assuming West Coast environmental constraints can be overcome. If computed on a well basis, about 400,000 barrels of California's daily crude production have been decontrolled. James Woods, Executive Vice President of the California Independent Refiners' Association, has estimated that decontrol of

heavy oil to 16° API would prompt additional West Coast production of 250 MB/D by 1985, assuming environmental constraints are overcome and heavy oil is excluded from the Windfall Profits Tax. Using the same assumption, Fred Hallmark, California State Supervisor of Oil and Gas, estimates production increases of 100-200 MB/D within three to five years. Additionally, a special entitlement subsidy has been made available to California refiners who process price-controlled heavy oil 20.1°-25.0° API gravity. This program is the most recent incarnation of the DOE/ERA mandated scheme to issue supplemental entitlements in order to improve demand for West Coast thermal oil. Current regulations allow California refiners to receive subsidies that decrease their per-barrel costs of lower tier heavy crude by \$1.84-\$2.11, depending on the exact API gravity of the heavy crude oil in question.

3.3 DOE PROGRAM TO DECONTROL PRICES OF INCREMENTAL PRODUCTION FROM CERTIFIED TERTIARY PROJECTS

Prior to heavy oil decontrol (Executive Order 12153), two-thirds of all heavy oil was controlled at the lower tier price of approximately \$6/B. Now that such oil can receive the market price of \$20-\$30 per barrel, the economics of recovery from producing heavy oil reservoirs are substantially improved. Operators producing heavy oil not covered by this decontrol order can petition ERA for price relief under a DOE program to decontrol incremental production from certified EOR operations. This "incremental tertiary" program became effective September 1, 1978, but only tertiary producers who could show current production as being otherwise uneconomic at the applicable ceiling price were eligible for "relief". The program was substantively amended on August 21, 1979 and now provides that incremental production from certain EOR technologies should receive market price on the basis of self-certification by a producer. Under amendments adopted, a producer may charge market prices for first sales of incremental crude oil resulting from projects

initiated after September 30, 1979 employing in situ combustion or unconventional steam-drive injection (wells deeper than 2500' or recovering oil with a gravity less than 10° API). Operators utilizing conventional steam-drive methods may apply to ERA for price relief on the basis that current operations are uneconomic at applicable price ceilings.

The decontrol of crude oil heavier than 20.0° API gravity as supported by the tertiary incremental pricing program is potentially an excellent economic incentive to increase recovery operations in currently-producing heavy oil reservoirs. The quality of this incentive, however, is somewhat weakened by treatment accorded heavy oil in the Windfall Profits Tax. President Carter requested Congress to exempt heavy oil 16° and less from the Windfall Profits Tax. Congress, however, while refusing to exempt heavy oil from the tax, did promulgate regulations wherein heavy oil received special tax treatment. The final version of the Windfall Profits Bill taxes oil heavier than 16.0° API at a special rate of 30 percent levied against revenues in excess of \$16.55 per barrel base. This special tax treatment is also afforded to all newly discovered crude oil and incremental production from certified tertiary projects.

3.4 DOE PROGRAM TO PROVIDE FRONT-END MONEY TO ASSIST CAPITALIZATION OF THERMAL EOR PROJECTS

Two very significant constraints to the implementation of thermal EOR projects are:

- (1) The risks created by the combination of high preproduction expenditures and uncertain process performance, and
- (2) The relatively low technological level of thermal techniques.

Although the economics of new ventures have been substantially improved by the 1979 decontrol of heavy oil, process risk and the

substantial length of time between large incurred investment costs and production revenue still present important constraints to thermal projects. The time duration necessary for development and field testing of some thermal EOR projects has been variably estimated at four to eight years. This time lag implies a financial penalty not met in the typical investment decision, which is geared to generate revenue no later than the end of the investment phase. DOE, on August 21, 1979, announced a program aimed at ameliorating these constraints. ERA amended 10CFR, Section 212.78 of the Mandatory Petroleum Price Regulations to provide front-end money to offset certain costs associated with certain EOR techniques. Amendments adopted permit thermal producers, as of January 1, 1980, to recoup 75 percent of specified costs that they incur provided that no more than \$20 million of such costs are recouped with respect to any particular property. Producers will recover these costs by charging market prices for some of their current production. As such, the program will end with the expiration of price controls in October 1981.

Under amendments adopted, producers may participate in the program after certification to ERA by certified mail that the project is recovering oil heavier than 16° API or employs one of the following thermal techniques:

- (1) Unconventional steam-drive injection
- (2) Conventional steam-drive injection
- (3) Cyclic steam injection
- (4) *In situ* combustion

Recoupable expenses include the costs of environmental regulatory compliance; a factor that has served as a major constraint to thermal project development and production. Laboratory and engineering costs may also be partially recouped. However, since the program is intended to encourage the actual use of EOR techniques, no more than \$1 million or 25 percent, whichever is less, of total allowed expenses may be based on engineering and laboratory expenses.

Allowable recoupable expenses vary by thermal technique. A listing of self-certifiable techniques and expensable items follows:

(1) Conventional Steam-Drive and Cyclic-Steam Injection

- a. The cost of any additives or gases used in conjunction with the steamflood to increase recovery efficiencies.
- b. The costs of produced fluid treatment required to assure environmentally acceptable disposal of waste fluids.
- c. The cost of surface boilers not fueled by oil or gas (such as coal and solar-powered generators) or non-surface boilers (such as downhole steam generators).
- d. The cost of fuel, excluding crude oil or refined petroleum products, natural gas and/or electricity, used by boilers for surface-steam generation.

(2) Unconventional Steam Drive (Wells > 2500' or Oil < 10° API Gravity)

- a. The cost of any additives or gases used in conjunction with the steamflood to increase recovery efficiencies.
- b. The costs of conventional hydrocarbon fuel-fired boilers provided that, with respect to a particular year, the amount of allowed expenses based on such costs may not exceed the amount of depreciation reported to the IRS with respect to such costs for that year.
- c. The costs of surface boilers not fueled by oil or gas (such as coal and solar-powered generators) or non-surface boilers (such as downhole-steam generators).
- d. The costs of fuel, excluding crude oil or refined petroleum products, natural gas and/or electricity, used by surface boilers for steam generation.
- e. Well costs.
- f. The costs of valves, regulators, insulation, coatings, etc., in fluid injection distribution systems, necessary to maintain the injection fluid quality of the project.

- g. The costs of produced fluid treatment required to assure environmentally acceptable disposal of waste fluids from the project.

(3) In Situ Combustion

- a. The costs of purchased compressed air plus any oxygen, steam, or water used in association with combustion at the project site.
- b. The costs of air compressors and prime movers used for air compression, provided that with respect to a particular year the amount of allowed expenses based on such costs may not exceed the amount of depreciation reported to the IRS with respect to such costs for that year.
- c. The costs of fuel for operation of air compressors and prime movers.
- d. Well costs.
- e. The costs of valves, regulators, insulation, coatings, etc., in fluid-injection distribution systems, necessary to maintain the injection fluid quality of the project.
- f. The costs of produced fluid treatment required to assure environmentally acceptable disposal of waste fluids from the project.

Industry's response to the upfront capital and incremental tertiary production programs has been very positive. Despite the young age of both programs, approximately 35 thermal projects have applied for certification.

The utility of the upfront capital program, however, is limited in several ways:

- Certified projects can raise money to offset upfront capital costs by deregulating lower-tier crude oil. However, many small and/or independent operators do not have lower-tier oil, or possess it in such limited quantities that its sale could not generate anywhere close to enough revenue to finance the large capital commitments necessitated by EOR operations.

- Assuming no Congressional action to override or change the present timetable for the decontrol of oil, the availability of lower-tier oil will be decreasing at an increasing rate culminating in decontrol on October 1, 1981. Thus, as fall 1981 approaches, there will be less and less old oil to decontrol in order to generate upfront capital. The value of the program as an incentive for EOR development will be collaterally decreased.

As an incentive, the Upfront Capital Program should increase domestic heavy oil production through the initiation of additional projects. This increased level of activity, during the period of crude oil price controls, should promote technical and commercial advances in thermal technologies. The program offers significant incentives to develop technology in the areas of downhole generators, methods of steam generation, and production in tar sands.

3.5 DOE COST SHARING PROJECTS

The U.S. Department of Energy currently has programs aimed at fostering the development of emerging EOR technologies. These programs include support of research and development, sponsorship of field tests, and provision of economic incentives for commercial production.

The U.S. Department of Energy currently participates in 21 field tests. Five of the field tests funded are thermal recovery projects. The federal government supports these projects on a cost-sharing basis with industry. The DOE reports that the government has committed \$10.0 million to thermal cost-sharing operations - 30 percent of the total costs of the projects. The extent of government support, as reported by the Department of Energy, is outlined in Exhibit 3-1.

Exhibit 3-1. DOE Thermal Cost Sharing Projects

<u>Thermal Recovery</u>	<u>Million Dollars</u>		<u>Operator</u>	<u>Field Location</u>	<u>Planned Completion Date</u>	<u>Status of Field Test</u>
	<u>Total Cost</u>	<u>DOE Share</u>				
<i>In Situ</i> Combustion and Water	7.3	2.5	Husky Oil Co.	Paris Valley Field, Calif.	1/80	Many problems including geology
Steam and Flue Gas	.8	.7	Carmel Energy Co.	Carlisle Field, Kans.	6/79	Successful stimulation in single five spot
Steam	8.7	2.0	Getty Oil Co.	Cat Canyon Field, Calif.	5/81	Successfully producing
<i>In Situ</i> Combustion and water (light oil)	8.2	3.1	Cities Service, Inc.	Bellevue Field, Louisiana	6/82	Has produced predicted oil on schedule
Steam	8.2	1.7	Chanslor Western Co.	Midway Sunset Field, Calif.	6/83	Producing heavy oil at economic cost

4. CONCLUSIONS

The government has recently implemented a series of regulations and programs designed to remove disincentives and/or prompt increased heavy oil recovery. The incentive portfolio is still being developed but, in including various decontrol provisions and upfront capital support, contains promising incentives to spur thermal development.

Exhibit 4-1 compares the full matrix of heavy oil utilization constraints to government incentives. Incentives not implemented, but of potential value, are also identified.

Exhibit 4-1. Matrix of Heavy Oil Utilization Constraints and Incentives

<u>CONSTRAINT</u>	<u>GOVERNMENT ACTION</u>	<u>OTHER POSSIBLE INCENTIVES</u>
Unpredictable Resource	<ul style="list-style-type: none"> ● Federal Cost Sharing Projects ● Upfront Capital Program ● Decontrol of New Production 	<ul style="list-style-type: none"> ● Loan Guarantees for Exploration ● Increased R&D Funding
Unpredictable Recovery Performance	<ul style="list-style-type: none"> ● Federal Cost Sharing Projects ● Price Decontrol Programs 	<ul style="list-style-type: none"> ● Increased R&D Funding ● Direct Government Funding ● Tax Incentives
High Front-End Production Costs: Delayed Payback	<ul style="list-style-type: none"> ● Upfront Capital Program 	<ul style="list-style-type: none"> ● Direct Government Funding
Economic Uncertainty Regarding Production Costs and Crude Prices	<ul style="list-style-type: none"> ● All Price Decontrol Programs 	<ul style="list-style-type: none"> ● Exclude Heavy Oil from Windfall Profits Tax
Environmental Regulations	<ul style="list-style-type: none"> ● Upfront Capital Program ● Price Decontrol ● Presidential Promise to Provide Access to Natural Gas to Fire Steam Generators 	<ul style="list-style-type: none"> ● Reduce Uncertainty about Regulations by Instituting Definite Statutory Time Limits ● Centralize Permitting Functions to Reduce Permit Issuance Delays ● Create a Regulatory "Ombudsman's" Office

APPENDIX II:

ENVIRONMENTAL ASPECTS OF HEAVY OIL RECOVERY
BY THERMAL TECHNOLOGY

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1. INTRODUCTION

Development of the nation's heavy oil resources is subject to varying degrees of impact caused by environmental regulations and economic factors, which are discussed hereunder. An attempt has been made to analyze the requirements of various environmental legislation, standards, or criteria enacted and enforced at the federal, state, and/or local levels of government to determine their relative impacts on thermal processes. In addition, the potential environmental deterioration likely to be generated by different EOR techniques and the nature or type of pollutants to be discharged during their application has been examined. Finally, an assessment of the potential constraints to thermal recovery techniques has been determined and possible resolution of problem environmental issues has been made.

The heavy oil resources identified in this study are distributed in several states throughout the country. In most of these states, federal environmental regulations and standards are mandatory and must be observed. However, California's environmental standards are considerably more stringent than those required by federal regulations, and are enforced very rigidly. Hence, in assessing the potential environmental constraints to thermal recovery processes, the applicable regulations enforced by the counties and the State of California may be considered as the most significant impediments to the application of such thermal processes. Therefore, California's environmental regulations are detailed and fully discussed in the body of the narrative. All applicable state regulations, however, are found in Appendix C.

In defining potential environmental constraints, federal and state environmental authorities, county officials and various state and gas authorities were contacted by phone or direct correspondence to acquire or ascertain the most recent or current applicable regulations, standards or criteria. However, it should be noted that all regulatory

processes are in a constant state of evolution, and, hence, it is not necessarily possible to predict that the statements made herein will be valid or binding within the immediate or long-range future. At best, it may be stated that the findings presented in this section have been found applicable to about September 1979. Moreover, the overall complexity of the several new pieces of legislation being formulated or standards being established doesn't allow one to readily define future potential constraints to thermal recovery processes as interpretations and enforcement standards in various regions can and do differ quite appreciably.

It must be understood that most environmental laws, regulations, and standards have been established in order to safeguard both human health and natural ecological conditions throughout the nation. Hence, such regulations are oriented towards preventing or ameliorating significant degradation of air and water quality or land use. Thus, the regulations pertaining to air and water quality and their relevance to thermal EOR processes are discussed at some length in the subsequent subsections.

2. AIR QUALITY REGULATIONS IMPACTING THERMAL EOR OPERATIONS

2.1 FEDERAL AIR QUALITY REGULATIONS

The federal government plays a leading role in developing the regulatory framework within which all thermal oil producers must operate. Federal environmental regulations and standards supercede all less stringent state and local regulations. State and local jurisdictions, however, do have the authority to promulgate and enforce environmental standards more stringent than their federal counterparts. California's environmental regulations, for example, greatly impact current and potential levels of thermal production. Federal and state environmental regulations and their applicability to enhanced oil recovery operations are detailed in Appendices B and C respectively. This section briefly describes the major federal environmental regulatory requirements that directly relate to thermal EOR operations.

The air quality issues associated with thermal production sites may be addressed by discussing major points of The Clean Air Act. The Clean Air Act of 1970 (PL 91-604) and its amendments constitute the principal federal legislation governing emissions and ambient levels of air pollutants. This legislation lays the basis upon which EOR operators must petition the EPA for construction permits to build thermal production facilities which utilize what are potentially "stationary sources of air pollution". The EPA bases its approval on two regulations:

- (1) The Prevention of Significant Deterioration Regulations
- (2) The Emission Offset Interpretative Ruling

The type of review requirements with which a new or modified source must comply depends on whether the source affects a dirty or clean air area. Sources which impact areas where the air is cleaner than the National Ambient Air Quality Standards (NAAQS) are subject

to regulations for Prevention of Significant Deterioration (PSD) of air quality (published in the June 19, 1978 Federal Register, pp. 26380-26410). New or modified sources which would affect dirty air areas (nonattainment areas) in which one or more of the NAAQS is violated will be subject to EPA's Emission Offset Interpretative Ruling. Of particular importance is the fact that a source may be subject to PSD for one pollutant and to the Offset Ruling for another pollutant, or may affect both clean and dirty areas for the same pollutant.

The NAAQS were originally established under the 1970 Clean Air Act to protect the health and public welfare. The seven contaminants so covered presently are sulfur oxides, suspended particulates, carbon monoxide, oxidants, hydrocarbons, nitrogen oxides and most recently, lead (see Exhibit 2-1). The EPA is expected to promulgate a standard for NO₂ based on a shorter averaging period than the currently-used annual average. Individual states may propose their own air standards, but these must be at least as or more stringent than federal standards. California's standards are presented in Exhibit 2-2.

States containing nonattainment areas are required to submit to EPA a "nonattainment" plan. In California, this means that each Air Pollution Control District (APCD) must have a nonattainment plan which meets the requirements of the Clean Air Act as amended. This plan must contain requirements for the review of new or modified sources which would include the requirement for such sources to achieve a "Lowest Achievable Emission Rate" for that particular source and pollutant, and to secure emission reductions for that particular pollutant in the locality of the source. No such sanctions exist for adoption of PSD regulations, however. Thus, it is possible in California that a source will need to obtain a nonattainment permit from the APCD and a PSD permit from EPA.

Exhibit 2-1. National Primary and Secondary Ambient Air Quality Standards

Air Contaminant	Averaging Time	Federal Primary Standard	Federal Secondary Standard
Nitrogen Dioxide*	Annual Average	100 $\mu\text{g}/\text{m}^3$ (0.05 ppm)	100 $\mu\text{g}/\text{m}^3$ (0.05 ppm)
Sulfur Dioxide	Annual Average	80 $\mu\text{g}/\text{m}^3$ (0.03 ppm)	- - -
	24-Hour	365 $\mu\text{g}/\text{m}^3$ (0.14 ppm)	- - -
	3-Hour	- - -	1300 $\mu\text{g}/\text{m}^3$ (0.5 ppm)
Suspended Particulates	Annual Geometric Mean	75 $\mu\text{g}/\text{m}^3$	60 $\mu\text{g}/\text{m}^3$
	24-Hour	260 $\mu\text{g}/\text{m}^3$	150 $\mu\text{g}/\text{m}^3$
Hydrocarbons (Corrected for Methane)	3-Hour 6-9 AM	160 $\mu\text{g}/\text{m}^3$ (0.24 ppm) [†]	160 $\mu\text{g}/\text{m}^3$ (0.24 ppm)
Ozone	1-Hour	240 $\mu\text{g}/\text{m}^3$ (0.12 ppm)	240 $\mu\text{g}/\text{m}^3$ (0.12 ppm)
Carbon Monoxide	8-Hour	10 mg/m ³ (9 ppm)	10 mg/m ³ (9 ppm)
	1-Hour	40 mg/m ³ (35 ppm)	40 mg/m ³ (35 ppm)
Lead	30-Day	1.5 mg/m ³	- - -

Source: 38 Code of Federal Regulations 25678, September 14, 1973

Note: ppm = parts per million
 $\mu\text{g}/\text{m}^3$ = micrograms per cubic meter
mg/m³ = milligrams per cubic meter

*Nitrogen dioxide is the only one of the nitrogen oxides considered in the ambient standards.

[†]Maximum 3-hour concentration between 6-9 AM.

Exhibit 2-2. California Ambient Air Quality Standards

Pollutant	Averaging Time	Concentration	Method
Oxidant (Ozone)	1 Hour	0.10 ppm (200 ug/m ³)	Ultraviolet Photometry
Carbon Monoxide	12 Hour	10 ppm (11 mg/m ³)	Non-Dispersive Infrared Spectroscopy
	1 Hour	40 ppm (46 mg/m ³)	
Nitrogen Dioxide	1 Hour	0.25 ppm (470 ug/m ³)	Saltzman Method
Sulfur Dioxide	24 Hour	0.05 ppm (131 ug/m ³) ⁹	Conductrimetric Method
	1 Hour	0.5 ppm (1310 ug/m ³)	
Suspended Particulate Matter	Annual Geometric Mean	60 ug/m ³	High Volume Sampling
	24 Hour	100 ug/m ³	
Sulfates	24 Hour	25 ug/m ³	AIHL Method No. 61
Lead	30-Day Average	1.5 ug/m ³	AIHL Method No. 54
Hydrogen Sulfide	1 Hour	0.03 ppm (42 ug/m ³)	Cadmium Hydroxide Stractan Method
Ethylene	8 Hour	0.1 ppm	-
	1 Hour	0.5 ppm	-
Visibility Reducing Particles	1 Observation	In sufficient amount to reduce the prevailing visibility to less than 10 miles when the relative humidity is less than 70%.	
<u>APPLICABLE ONLY IN THE LAKE TAHOE AIR BASIN:</u>			
Carbon Monoxide	8 Hour	6 ppm (7 mg/m ³)	NDIR
Visibility Reducing Particles	1 Observation	In sufficient amount to reduce the previlaing visibility to less than 30 miles when the relative humidity is less than 70%.	

2.1.1 Prevention of Significant Deterioration

The 1977 Clean Air Amendments keep active the EPA promulgated regulation for the Prevention of Significant Deterioration (PSD). The basic intent of these regulations is to keep "clean air clean". This is accomplished by placing limitations on the amount that air quality can be degraded or deteriorated, above what is termed "baseline concentration".

Source categories have been specified as subject to the PSD regulations and are listed in Exhibit 2-3. PSD applies to these sources for any pollutant regulated under the Clean Air Act whose potential emission rate is greater than 100 tons/yr. Potential emission rate refers to the emission rate to be expected without air pollution control equipment.

Exhibit 2-3. PSD Major Stationary Sources

Potential Emission of any Pollutant Greater than 100 Tons/Yr:

1. Fossil Fuel-Fired Steam Electric Plants (More than 250 MMBtu/hr Input)
2. Coal-Cleaning Plants (With Thermal Dryers)
3. Kraft Pulp Mills
4. Portland Cement Plants
5. Primary Zinc Smelters
6. Iron and Steel Mill Plants
7. Primary Aluminum Ore Reduction Plants
8. Primary Copper Smelters
9. Municipal Incinerators (Capable of Charging More than 250 Tons Refuse/Day)
10. Hydrofluoric, Sulfur, and Nitric Acid Plants
11. Petroleum Refineries
12. Lime Plants
13. Phosphate Rock Processing Plants
14. Coke Oven Batteries
15. Sulfur Recovery Plants
16. Carbon Black Plants (Furnace Process)
17. Primary Lead Smelters
18. Fuel Conversion Plants
19. Sintering Plants
20. Secondary Metal Production Plants
21. Chemical Process Plants
22. Fossil Fuel Boilers (Or Combinations Thereof Totalling More than 250 MMBtu/hr Input)
23. Petroleum Storage and Transfer Units (With Total Storage Capacity Exceeding 300 Thousand Bbls.)
24. Taconite Ore Processing Plants
25. Glass Fiber Processing Plants
26. Charcoal Production Plants

And

Notwithstanding the sources above, any source which emits or has the potential to emit 250 tons/yr or more of any pollutant regulated under the act.

In addition to the categories specified, there is an additional "catchall" category for any source whose potential emission rate is greater than 250 tons/yr of any pollutant regulated under the act.

Steam generators which are greater than 250 MMBtu/hr heat input would be in the source category listing and subject to PSD review for each attainment pollutant greater than 100 tons/yr. However, most steam generators in California are in the 50 MMBtu/hr size range. Thus, the second category of sources with emissions greater than 250 tons/yr (potential emissions) would apply to these. The typical emissions for a 50 MMBtu/hr steam generator, burning 1.09 percent sulfur fuel, are given in Exhibit 2-4.

Exhibit 2-4. Typical Emissions from a 50 MMBtu/Hr Steam-Generating Unit Burning Fuel with 1.09 Percent Sulfur Content By Weight (Tons/Yr) (Uncontrolled Emissions)

SO ₂ :	220 Tons/Yr
NO ₂ :	77
TSP:	21.4
CO:	6.4
HC:	3.1

It can be seen then that two steam generators would be subject to PSD for SO₂, and four steam generators would result in NO₂ being subject to PSD review as well.

2.1.1.1 Best Available Control Technology

Sources under PSD must apply Best Available Control Technology (BACT) for each applicable pollutant. BACT means an emission limit or control technology representing the maximum degree of reduction with respect to a particular source and pollutant, taking into account energy, environmental, economic impacts, and other costs.

(a) BACT for SO₂

At the present time, the EPA has determined BACT for the control of SO₂ from oil-fired steam generators and other similar oil-burning equipment. They maintain that BACT for this type of equipment is 0.5 percent sulfur by weight in fuel or the equivalent rate achieved by scrubbing.

(b) BACT for NO₂

For NO₂, the EPA is requiring a case-by-case analysis. They maintain that BACT at a minimum shall be a combustion modification of the burner to result in the least amount of oxygen to be consumed for combustion. Control technologies beyond combustion modification must be examined and evaluated in terms of environmental, energy, and economic impacts. Other such technologies which exist are relatively few at this point. The prominent technology in this field is Exxon's Thermal DeNox process, which utilizes ammonia injection. Reduction rates vary, however, and good results are critically dependent upon the temperature of the reaction and residence time in the flamebox portion of the burner. Because of the variability in steam generator and burner design (and consequently variations in temperature and residence times), it is impossible to predict the amount of reduction to be achieved using this process. Economic considerations also enter into the use of this technology. Presently, Exxon holds the patent for the process. Use of this process, therefore, results in the company paying approximately \$15,000 for the license fee for each generator which uses it.

Getty Oil Company and Chanslor-Western Oil and Development Corp. have decided to use ammonia injection on several of their units for testing purposes. They wish to demonstrate to the EPA what the magnitude of reduction of NO₂ emissions would be using the process. Results of their experiments could affect the criteria of BACT for steam generators with regard to NO₂ in the future.

Other experiments being conducted are by Union Oil Company. They are working with Dow Chemical Corporation in developing and testing a chemical which, when added to these chemicals in an SO₂ scrubber, would reduce the NO₂ emission as well. Results of these experiments are not as yet known.

(c) BACT for Particulate Matter

BACT for particulate matter has not been clearly defined, though the EPA maintains that SO₂ scrubbers should satisfy the BACT requirements for particulates. This is because the SO₂ scrubbers, although primarily designed for SO₂ removal, also remove a small percentage of particulate matter. The amount of removal has not been adequately substantiated, however. Applicants claiming a certain percentage reduction, for example 40 percent, would have this reduction included as a condition on the PSD permit.

Particulate matter emissions from steam generators are small, and it would take an average of nine or more 50 MMBtu/hr units to emit more than 250 tons/yr (potential emissions). Projects of this size would be required to use scrubbers for SO₂ control, and in such instances, the EPA would consider use of these scrubbers to be BACT for particulate matter as well.

2.1.1.2 Second-Tier Analysis

The PSD regulations, as promulgated in the June 19, 1978 Federal Register, use a two-tiered analysis which allows for the evaluation of proposed facilities for both potential and controlled emissions. As mentioned, sources falling into the category greater than 100 tons/yr potential for the source categories, or greater than 250 tons/yr potential emissions for all other sources would be considered to be a major source. Major sources would then proceed to the second-tier criteria analysis.

As in the first-tier analysis, there are cutoff limits for second-tier review. These limits relate to controlled or "allowable" emissions exceeding 50 tons/yr, 1,000 lbs/day, or 100 lbs/hr, whichever is the most stringent. Any source falling below these allowable emission rates would then be exempt from BACT and an air quality analysis.

Control devices can be taken into account in determining what are termed "allowable emissions". Briefly defined, "allowable emissions" are those emissions "allowed" under federal or state emission limitations, or emission limitations which can be enforced through a permit condition. Since the emission rates obtained through the use of air pollution control equipment can be regulated through a permit condition, allowable emissions may take into account such equipment.

It is important to note that allowable emissions do not take into account emission reductions occurring within or outside the source. ("Source" is a term which encompasses the aggregation of equipment or facilities which comprise it, provided such equipment is on contiguous property under common ownership. Several steam generators in the same oil field, for example, may comprise one source.) Thus, even if there is an emission reduction at other facilities within the locality of the proposed source resulting in net emissions below the 50 tons/yr cutoff, this would not necessarily exempt the source from further PSD review. The allowable emissions are examined in light of the new or modified facility.

2.1.1.3 Air Quality Analysis

For those pollutants which do not fall below the second-tier cutoff levels, an air quality analysis must be performed. The analysis is dependent on the area classification in which the source is located. The PSD regulations establish three "classes" of clean air areas. Each class has been assigned numerical increments for particulate matter and sulfur dioxide concentrations (Exhibit 2-5). Class I increments permit only minor air quality deteriorations, Class II permit a moderate amount of deterioration, and Class III increments permit the most air quality deterioration.

Exhibit 2-5. Prevention of Significant Deterioration Maximum Allowable Increments (In Micrograms Per Cubic Meter)

Pollutant	Class I	Class II	Class III
<u>Particulate Matter</u>			
Annual Geometric Mean	5	19	37
24-Hour Maximum*	10	37	75
<u>Sulfur Dioxide</u>			
Annual Arithmetic Mean	2	20	40
24-Hour Maximum*	5	91	182
2-Hour Maximum*	25	512	700

*May be exceeded once per year.

The PSD regulations require that a source demonstrate that no violations of the NAAQS for NO₂, CO, and HC will occur (provided that the area the source proposes to locate in is attainment for these pollutants). While NO₂, CO, and HC can in effect be "deteriorated" to the NAAQS for these pollutants, for SO₂ and particulate matter the amount of deterioration is limited to "increments" for that particular class for the area in which the project would be located.*

The basic intent of the PSD regulations is to keep "clean air clean." This is accomplished, as mentioned above, by placing limitations

* Concentration predictions are accomplished through the use of air quality models. The EPA requires that sources include details of modeling analysis in the evaluation of the projected impacts. They also require that any models used for evaluating impacts for a PSD permit shall be an EPA-approved model.

on the amount the air quality can be deteriorated (i.e., increments) above what is termed the "baseline concentration". Baseline concentration is defined as the ambient air quality concentration level reflecting actual air quality as of August 7, 1977, minus concentrations from major PSD sources which began construction after January 6, 1975.

Thus, in determining baseline concentration, the levels reflecting air quality as of August 7, 1977 must first be determined. This can be obtained by actual air monitoring data, or lacking that, background can be simulated through air quality modeling using actual emission data in the area of concern. After this level is established, it is then necessary to determine the concentrations due to major PSD sources which began construction after January 6, 1975. These concentrations would be obtained by air quality modeling, and once computed are subtracted from the August 7, 1977 concentration level. The difference is then the baseline, and the amount of deterioration allowed from that level is governed by the air quality increment for the particular class designation in which the project is located. In the case of the oil fields, all are Class II, and there are no nearby Class I areas.

It is important to note that the concentrations from the major PSD sources which began construction after January 6, 1975, although subtracted from the original baseline consume (or count against) the maximum allowable increment (see Exhibit 2-6). Thus, in certain areas of the country, it may be possible that some of the increment has been "used up" by major PSD sources.* This may be the case in the Kern River Oil Field area, in which the majority of sources existing there have been constructed after January 6, 1975. Many of these steam generators would qualify as major PSD sources. As will be discussed later, the Kern River Oil Field is considered to be nonattainment for SO₂, although the areas surrounding it are considered to be attainment.

* Similarly, major PSD sources commencing prior to January 6, 1975 remain as part of the baseline, even if such sources were not in operation as of August 7, 1977.

Exhibit 2-6. Computation of Baseline and Determination of Maximum Allowable Ambient Limit Under PSD Increment

NOTES:

- 1) IF BASELINE PSD INCREMENT > NAAQS, THE NAAQS IS THEN THE MAXIMUM LIMIT.
 - 2) THIS SHADED AREA, DETERMINED IN FIGURE 1-8 ABOVE, WILL CONSUME INCREMENT.
 - 3) FUTURE PROJECTS CUMULATIVELY CONSUME REMAINDER OF THE INCREMENT.
- FUTURE PSD PROJECTS MUST NOT EXCEED THE MAXIMUM LIMIT.

Increment consumption is looked at from a cumulative viewpoint. That is, if a source consumes part of the increment, then the next source to apply for permits must work within the remaining increment. Thus, a proposed PSD source must consider the following sources as consuming increment:

- 1) Major PSD sources which commenced construction after January 6, 1975.
- 2) All other sources which commenced after August 7, 1977, regardless of size.

Thus, the second category implies that in the PSD air quality analysis, all sources must be included in determining how much of the increment has been consumed. This would include the sources with emissions below the second-tier cutoff limits (50 tons/yr). These sources, although exempt from the air quality analysis, still consume increment.

The air quality modeling analysis should include areas no farther than 50 km downwind of the source, or to a distance where the predicted concentrations from the source fall below the significance levels presented in Exhibit 2-7. This 50 km limit and the significance levels do not apply for Class I areas. The effect of the project on a Class I area must be determined. Some judgment must be made in each case, since the accuracy of models falls off with the increase in distance.

Exhibit 2-7. Significance Levels for PSD and Nonattainment Areas

<u>Pollutant</u>	<u>Averaging Time</u>				
	<u>Annual</u>	<u>24-Hour</u>	<u>8-Hour</u>	<u>3-Hour</u>	<u>1-Hour</u>
SO ₂	1 UG/M ³	5 UG/M ³	---	25 UG/M ³	---
TSP	1 UG/M ³	5 UG/M ³	---	---	---
NO ₂	1 UG/M ³	---	---	---	---
CO	---	---	0.5 MG/M ³	---	2.0 MG/M ³

2.1.2 The Emission Offset Interpretative Ruling

The EPA bases approval in nonattainment areas on the Emission Offset Interpretative Ruling which was published in the January 16, 1979 Federal Register. This ruling incorporates comments received on EPA's original interpretative ruling published December 21, 1976. It also embodies changes stipulated by the Clean Air Act as amended on August 7, 1977.

The main provisions of the ruling are the requirements for new or modified sources to meet the "lowest achievable emission rates" (LAER) for the problem pollutant(s), and to obtain more than equivalent offsetting emission reductions (emission offsets) from existing sources.

As mentioned previously, EPA's Offset Ruling was terminated as of July 1, 1979. For those districts that received approval of their nonattainment plans, the new source review requirements of that district were to be in effect. The source would then obtain the permit from the district rather than the EPA, although it is possible that for sources affecting attainment as well as nonattainment areas, they will still need to secure EPA's PSD permit. However, for those districts which failed to receive approval of their nonattainment plan by June 30, 1979, no permits for major new sources applied for after that date would be issued.

Applications made for new or modified sources in nonattainment areas are first reviewed to determine the potential emission rate (uncontrolled emissions) of all problem pollutant(s) (pollutants for which the standards have been violated in the area of project location). Uncontrolled emissions refer to the emissions from the project occurring without the use of air pollution control equipment. If the potential emission rate is greater than 100 tons/yr, the source is subject to the ruling for that pollutant and is considered a major source. For example, a source having potential emissions greater than 100 tons/yr

of SO₂ is a major source of SO₂ under the ruling. The designation of major source, therefore, is pollutant specific.

Once a source is determined to be major for one or more pollutants, it is then reviewed to determine if it will be in compliance with all applicable emission requirements. These may be a New Source Performance Standard (NSPS) or an emission limit contained in a district or state rule.

After this determination is made, the next step is to review the allowable emissions of the source. As discussed previously, allowable emissions refer to the emissions after meeting the emission requirements contained in either the NSPS, state or district rule, or a permit condition. Thus, allowable emissions refer essentially to controlled emissions. If the allowable emission increases from the new or modified source are less than 50 tons/yr, 1000 lbs/day, or 100 lbs/hr (whichever is more stringent), the review ends at this point.

If the allowable emissions are greater than the above cutoff limits, the source must meet specific requirements which differ according to the different scenarios described below:

- Sources locating in nonattainment areas must meet the following conditions:
 - Apply technology to obtain what is termed "lowest achievable emission rate" (LAER),
 - Demonstrate that all sources owned by the applicant in the state are in compliance with all emission limitations and standards,
 - Obtain emission offsets to achieve a net reduction in emissions, and
 - Show that the project results in a net air quality benefit.

- Sources locating in unclassified or attainment areas, or clean portions of designated nonattainment areas
 - The effect of the project on the neighboring or bordering nonattainment areas must be examined. If the concentrations resulting from the project exceed certain "significance levels" (see Exhibit 2-7) in the actual area of nonattainment, the source must obtain LAER and offsetting reductions.
 - The effect of the source in the attainment area must also be examined. If the source is not subject to PSD regulations, it must be demonstrated that the National Ambient Air Quality Standards will not be violated in the area of attainment.
- Sources in attainment areas, or "clean" portions of nonattainment areas which would cause a new violation of an NAAQS: If a source is in an attainment area (or a clean portion of a nonattainment area) and modeling shows that it would cause a violation of an NAAQS in the attainment area, the source may be required to:
 - Meet a more stringent emission limitation (not necessarily LAER, and
 - Achieve emission offsets.

The above two requirements would be required to the extent that the violation of the NAAQS would be prevented.

2.1.2.1 Lowest Achievable Emission Rate (LAER)

The lowest achievable emission rate, or LAER, is an emission rate for a particular source based on the most stringent of the following:

- (1) The most stringent limitation in any state implementation plan in the U.S. for this type of source unless it is demonstrated that such a limit is not achievable, or
- (2) The most stringent emission limitation achieved in practice by the type of source in question.

LAER, then, is a type of emission rate which reflects the control technology available and the emission limits required by law. Such a rate for a type of source is determined by considering the emission limits for this type of source contained in the SIP's of the U.S. In addition, the lowest emission rate currently achieved in practice for this type of source must be considered. Also, in no instance can the LAER be less stringent than the amount allowed under an applicable new source performance standard. Unlike the definition of Best Available Control Technology, LAER does not take into account energy or economic considerations and is, thus, more stringent than BACT.

- LAER FOR SO₂

- LAER for oil-fired steam generators and other similar oil-burning equipment is considered to be 0.25 percent sulfur by weight in fuel or the equivalent rate achieved by scrubbing. This is based on technology achievable in practice for these types of sources. LAER is a changing thing, however. As SIP requirements change and become more stringent, so too must the LAER reflect such changes. Similarly, as developments and advances in technology are achieved, LAER must also reflect the use of such technology. In this regard, LAER for steam generators may be undergoing further change, since there will be some scrubbers in use in Kern County which will achieve up to 90-95 percent removal efficiency. This is equivalent to 0.1 percent sulfur by weight in the fuel in some cases.

- LAER for NO₂

- LAER for NO₂ has not been a considerable issue due to the fact that the only nonattainment area for NO₂ is in the Los Angeles Air Quality Control Region. However, major sources for NO₂ which are locating in this region will be required to achieve LAER for NO₂. In Orange County, the Chanslor-Western Oil and Development Corp. is using Exxon's Thermal DeNOx process (ammonia injection) for reductions in NO₂. Since this is a technique which has been demonstrated to be achievable in practice in the U.S. as well as in Japan, it is likely that the emission rate achieved using ammonia injection would be the LAER. Use of steam generators in this area is somewhat limited, although future development of steam generation is not necessarily precluded.

- LAER for Hydrocarbons

- Hydrocarbon emissions of most concern occur from the wells when the hydrocarbon-laden steam is vented to the atmosphere. LAER, for this source of hydrocarbon, is considered by EPA to be a vapor collection system for the wellheads with a minimum efficiency of 85 percent. Although closed systems with effective removal efficiencies of 100 percent are in practice in some situations, requirement of these systems for new sources are to be determined on a case-by-case basis. This is because the closed system may not be technically feasible for some smaller operations.

2.1.2.2 Emission Offsets

As discussed above, emission offsets are required for sources locating in nonattainment areas, or in areas which would affect non-attainment areas. Although an emission offset is in effect an emission reduction, there are certain provisions which must be met in order for an offset to be considered valid.

Merely reducing the emissions from an existing source is not always enough to qualify for a valid emission offset credit. It is necessary for a reduction to go beyond that which is required by law. This emission limit required by law is referred to as the emission baseline. The baseline emission offset limit is defined as the SIP emission limitations in effect at the time the application to construct or modify the source is filed. Credit for emission offset purposes for existing sources may be given only for that portion of control which goes beyond that required by the SIP.

2.1.2.3 Nonattainment Areas and Pollutants

The primary nonattainment pollutants in the areas of steam generator development are particulate matter and ozone (oxidant). Violations of these standards occur in the Los Angeles, North Central and San Joaquin AQCR's. SO₂ nonattainment areas have been the center for some recent controversies between the California Air Resources Board and Kern and Los Angeles Counties.

In the March 3, 1978 Federal Register, the EPA published a list of all the counties in the country and their designation regarding attainment status. Kern County is designated nonattainment for SO₂. The EPA's policy towards this is as follows: Although the entire countywide area is designated as nonattainment for SO₂, the primary area of concern in Kern County is the Kern River Oil Field, where a recent violation of the 24-hour SO₂ standard has been reported. Also, in Kern County, a small portion in the northern area of the Midway-Sunset Oil Field is considered as a potential area where the standards of SO₂ may be exceeded. The EPA, in its reviews, considers areas outside the Kern River Oil Field and northern Midway-Sunset Oil Field to be attainment for SO₂. Sources locating in Kern River, for example, must obtain a LAER. If the emissions after LAER are still greater than 50 tons/yr, offsets are required.

For steam generators which locate outside the Kern River proper, but in the general vicinity (such as the Kern Front Field), the second scenario outlined earlier applies. Specifically, the applicant must demonstrate that the concentrations of SO₂ due to the source do not exceed the significance levels in the Kern River Oil Field (see Exhibit 2-7). Of course, if the emissions from the source are less than 50 tons/yr, no such review is required.

2.2 CALIFORNIA AND DISTRICT AIR QUALITY REQUIREMENTS

New source review rules differ in most cases from county to county. With the exception of the Bay Area Air Quality Management District, the air pollution districts in California have not had their permit rules approved by the EPA as a part of the nonattainment plan required by the Clean Air Act. Consequently, sources must obtain permits for new or modified sources from both the districts and from the EPA whose rules were discussed above.

States are required to submit permit rules as part of a general nonattainment plan, mandatory under Part D of the Clean Air Act. As discussed earlier, approval of this plan for the various districts in California must be obtained by June 30, 1979, or no permits will be issued for sources for which applications are filed after that date.

Permit rules for attainment areas are required under Part C of the act and must conform to the requirements of PSD. No sanctions have been imposed for this portion of the Clean Air Act. Thus, it may be possible in some districts to have an approved nonattainment plan, but the attainment portion of the plan may be disapproved. In such instances, sources would be required to obtain the district permit for the nonattainment portion of the project and EPA's PSD permit for the attainment portion of the project.

On February 16, 1979, the California Air Resources Board adopted a newly-revised Model New Source Review Rule. This rule is more stringent than EPA's current Interpretative Ruling. A district's permit rule must conform to ARB's Model Rule in stringency, before the state will submit the district's rule to the EPA as part of the non-attainment plan. The state is the only body which may submit a plan to the EPA for approval under the SIP. The districts cannot directly submit their rules to the EPA, even if such rules meet the requirements of the Clean Air Act.

In some instances (such as in the South Coast Air Quality Management District), the ARB will adopt the Model Rule for the district. In other instances, the ARB itself will administer the permit review program as is now being done in Sutter County.

There is some feeling that the ARB may do this for Kern County, though both Kern County and industry are opposed to such a move and would object to it formally if it were attempted. Following is a

discussion of the general requirements of ARB's Model New Source Review Rule. It is important to note that this Model Rule is not in effect in any district; the Model Rule is the criteria document against which individual district rules will be compared for stringency.

2.2.1 Air Resources Board Model New Source Review Rule

The Model Rule applies in both attainment and nonattainment areas. All sources, regardless of emission levels, must first demonstrate compliance with all district rules and regulations. It must also demonstrate that all company-owned sources in the state are in compliance with all emission limitations and standards which are part of the SIP approved by the EPA.

For sources with emissions greater than 250 lbs/day, Best Available Control Technology is required. The Model Rule definition of BACT is closer to LAER, than it is to EPA's BACT definition, although economics may be considered. For CO, however, the emission cutoff limit is that amount above which it is determined that there will be a violation of the NAAQS for CO.

The BACT requirement is not pollutant specific. That is, if one pollutant is over the cutoff limits, BACT is required for all the other pollutants. Naturally, for pollutants of small amounts, BACT would not be considered good technology for economic and technical reasons.

If after application of BACT, emissions of any pollutant are greater than 250 lbs/day, the source must meet specific requirements which differ according to two different scenarios as follows:

- Sources Locating in Nonattainment Areas

- In this situation, sources of hydrocarbons and/or NO_x (greater than 250 lbs/day after BACT) must obtain offsets. Offsets must be obtained in the ratio of 1.2:1, and within 15 miles of the Source. Sources of SO₂, CO

and TSP may not need offsets if it is demonstrated that the emissions will not cause a new violation of any NAAQS for these pollutants or make an existing violation worse.

- Sources Locating in Attainment Areas

- In this situation, for any pollutant for which it is demonstrated that there will be no new violations, or no worsening of existing violations, no offsets will be necessary. Demonstration would be accomplished through modeling; however, modeling would not be required if the applicant obtained emission offsets to effect a zero increase in emissions.

2.2.2 Monterey Bay Unified Air Pollution Control District

(a) Permits

The Monterey Bay New Source Review Rule was approved by the ARB in 1976, but has not as yet received approval from the EPA. The cutoff limit for review of sources is 25 lbs/hr, 250 lbs/day (250 lbs/hr, 2500 lbs/day for CO). For modification, total emissions from the source after the modification are considered, as opposed to the delta, or increase from such modification. Thus, an existing source if increased to over 25 lbs/hr by a modification, would be subject to review under the rule. A source emitting pollutants greater than these cutoff limits would have to obtain offsets to secure a zero increase in nonattainment areas. In attainment areas, the source would be required to demonstrate that the project would not violate any California or National Ambient Air Quality Standards. There is no requirement for BACT review.

(b) Emission Limitations

Rule 403: Rule 403 of the Monterey County Rules and Regulations sets a particulate emission limit of 0.15 gr/SDCF as measured. The "as measured" refers to the actual measured value rather than one corrected to 12 percent CO₂ as other rules require.

Rule 412, 413: These rules in combination require that for combustion sources, a fuel containing no greater than 0.5 percent sulfur by weight be used, or the equivalent rate which could be achieved by scrubbing. Thus, a source may use 1.5 percent sulfur fuel, but would have to scrub with an efficiency of at least

77 percent to achieve the SO₂ emissions equivalent to burning a 0.5 percent sulfur fuel. The rule also limits SO₂ to 283 ppm (instack concentration) with 20 percent excess air.

Rule 404-b: Limits NO₂ emissions to 140 lbs/hr.

2.2.3 Santa Barbara County Air Pollution Control District

(a) Permits

The Santa Barbara County New Source Review Rule was approved by the ARB on January 26, 1978, but has not received approval from the EPA for their nonattainment plan. The cutoff limit for review of new sources is 5 lbs/hr (50 lbs/hr for CO). For modifications, if total emissions from the source exceed 15 lbs/hr (150 lbs/hr for CO), the modification would be subject to review under the rule. New sources must apply BACT for each pollutant greater than 10 lbs/hr (100 lbs/hr for CO). For modifications, if the entire source is greater than 15 lbs/hr (150 lbs/hr for CO), BACT must be applied to those modifications resulting in increase only. Their BACT does not take into account economic considerations. In addition, for both new sources and modifications, it must be demonstrated that there will be no violation of any state or National Ambient Air Quality Standard. Emission offsets are not spelled out as a requirement, but it is implied that they be obtained for nonattainment areas.

(b) Emission Limitations

Rules 19 and 19-b: Set a particular emission limit of 0.3 gr/SCF calculated to 12 percent CO₂ at standard conditions.

Rules 32 and 32.1: Same as Monterey's Rules 412 and 413 - sets a sulfur-in-fuel limit for liquid and solid fuels not to exceed 0.5 percent, or that equivalent rate achieved by scrubbing.

Rule 19-a: Sulfur compounds are limited to 0.2 percent by volume.

Rule 39: In addition to the rules above, upper limits of emissions are set for the following pollutants:

SO₂: 200 lbs/hr
NO₂: 140 lbs/hr
TSP: 10 lbs/hr

2.2.4 South Coast Air Quality Management District

(a) Permits

The South Coast Air Quality Management District Rule was adopted for them by the California Air Resources Board on October 8, 1976. The cutoff limit for review of new sources is 250 lbs/day. For modification, the cutoff is the same and refers to the entire source after modification rather than the delta or increase. Sources and modifications subject to the review must apply BACT. As above, this BACT does not take into account economic considerations. If after application of BACT, the emission increase from a new source, or the total emissions from a modification are less than 25 lbs/hr, 250 lbs/day (250 lbs/hr, 2500 lbs/day for CO), no further review is necessary. If greater than these levels, it is necessary to demonstrate that there will be no violation of any state or National Ambient Air Quality Standard. In nonattainment areas, this implies that offsets are required, although an absolute requirement and provisions for offsets are not spelled out.

(b) Emission Limitations

Information not available.

2.2.5 Fresno County Air Pollution Control District

(a) Permits

Fresno County's New Source Review Rule states their cutoff limits in metric units. Sources emitting pollutants greater than a 5 kg/hr, 50 kg/day (50 kg/hr, 500 kg/day for CO), or 11 lbs/hr, 110 lbs/day are required to use BACT. Fresno County's definition of BACT takes into account economic considerations and is closer to the EPA BACT definition. With BACT, the source may then emit up to 10 kg/hr, 100 kg/day (100 kg/hr, 1000 kg/day for CO) or 22 lbs/hr, 220 lbs/day without having to go through review.

Sources exceeding these levels in nonattainment areas would require emission offsets. In attainment areas, it is necessary to demonstrate that there would be no violation of California or National Ambient Air Quality Standards.

Fresno County looks at the increase in emissions from modifications as opposed to the total emissions of the source after modification. Fresno's rule allows exemptions for sources or modifications that represent significant advances in the development of an environmental control technology or that appears to offer extraordinary environmental or public health benefits. Concurrence from ARB is required for these types of exemptions.

(b) Emission Limitations

Information not available.

2.2.6 Kern County Air Pollution Control District

(a) Permits

At the present time, Kern County's New Source Review rule states that sources with emissions greater than 15 lbs/hr (150 lbs/hr for CO) are subject to review. Modifications look at only the increase rather than total emissions after the modification. BACT is not a requirement - only that emissions do not cause a violation of any California or National Ambient Air Quality Standard.

Kern County has submitted a revised New Source Review Rule to the ARB, but they have not approved it. The rule would go into effect when the EPA approved it as part of the non-attainment plan. The revised rule provides a cutoff limit of 15 lbs/hr, 150 lbs/day (150 lbs/hr, 1500 lbs/day for CO) on a pollutant-specific basis. Modifications would look at the increase rather than total emissions. For sources with emissions greater than the cutoff levels, BACT would be required. BACT is defined as Fresno County defines it. Further, the applicant must demonstrate that there would be no violation of any California or National Ambient Air Quality Standard. Emission offset requirements are spelled out, but are not as stringent as ARB's Model New Source Review Rule.

Kern County, however, is unofficially enforcing the proposed rule. Although, officially BACT is not required, they are requiring all steam generators greater than 15 lbs/hr to use scrubbers.

(b) Emission Limitations Applicable to Steam Generators

As mentioned above, Kern County is requiring steam generators to use scrubbers on an unofficial basis. Officially, the emission limitation for combustion sources for SO₂ is 200 lbs/hr as defined below. Kern County also unofficially requires vapor recovery on wellheads.

Currently, the ARB has a proposed rule which went to public hearing on March 23, 1979. This rule would affect all steam generators greater than 15 MMBtu/hr heat input in Kern County only. The proposed rule states that for steam generators, those issued permits prior to February 21, 1979 and not presently required to use scrubbers, an emission rate of 0.24 lb SO₂/MMBtu heat input must be achieved by January 1, 1982. For those steam generators issued permits after March 23, 1979, or prior to February 21, 1979 but using scrubbers, an emission rate of 0.116 lb SO₂/MMBtu heat input must be achieved. As a result of this hearing, a six-month extension was granted during which time Kern County could draft an alternative rule. If the alternative rule met with the approval of CARB, it would then be in effect rather than CARB's proposed rule. Kern drafted a rule which affects only those generators in critical SO₂ areas, rather than on a countywide basis.

3. WATER QUALITY REGULATIONS IMPACTING THERMAL EOR OPERATIONS

3.1 FEDERAL WATER QUALITY REGULATIONS

Numerous federal laws and regulations to safeguard the quality of the nation's surface and underground water supplies have been enacted. The main laws are described below:

3.1.1 Federal Water Pollution Control Act (FWPCA)

The Federal Water Pollution Control ACT (P.L. 92-500), commonly referred to as the Clean Water Act, has a national goal of eliminating the discharge of all pollutants into navigable waters by 1985. In the interim, there is a "fishable-swimmable" goal for achieving the protection and propagation of aquatic life and protecting recreational facilities. The act also has the goal of prohibiting the discharge of toxic pollutants into the nation's water.

To achieve the stated goals, EPA is developing comprehensive programs for the prevention, reduction, and elimination of pollution in navigable waters and ground-waters.

The FWPCA establishes a system of discharge and ambient standards for regulating pollution from nonmunicipal (i.e., industrial) point source categories under which thermal EOR processes fall. Sections 301 and 306 authorize the promulgation of discharge standards for this type of existing and new thermal EOR fields, respectively. Like the New Source Pollution Standards (NSPS) under the Clean Air Act, NSPS's under Section 306 consider the performance, cost, energy requirements, and cross-media (nonwater quality) environmental impacts of control technology. Under Section 303, states must establish and obtain EPA's approval of water quality standards.

Under Section 304(3), EPA has the option to promulgate supplemental regulations for toxic and hazardous pollutants to ensure that

all sites maintain careful environmental management practices. The intent of supplemental regulations is to control runoff, spillage, and leakage of materials. This includes regulation of the activities which disturb vegetation cover and/or leave tailing piles to prevent runoff.

Effluent guidelines are to be enforced through the National Pollution Discharge Elimination System (NPDES), established pursuant to Section 402. To receive a permit, the applicant must comply with all applicable effluent limitations for the particular discharge under thermal EOR operations. Ambient standards prevail where their attainment requires discharge limitations more stringent than those of the NSPS.

Additionally, under Section 307, the 1977 amendments to P.L. 92-500 require the installation of Best Available Technology (BAT) controls by July 1, 1984 for the 65 chemical classes and derivatives listed in the consent decree settlement under Natural Resources Defense Council (NRDC) vs. Train.

Under Section 304(a) of P.L. 92-500, EPA is charged with the responsibility to publish the knowledge of all identifiable effects on health and welfare which may be expected from the presence of pollutants in any body of water. Thus in July 1976, EPA published "Quality Criteria for Water" covering 52 physical, chemical, and biological characteristics of water. While the "Quality Criteria for Water" does not have direct regulatory force, it provides guidelines for developing both discharge and ambient standards for formulating and evaluating federal and state water quality programs and standards.

The criteria provides the upper limit on allowable concentrations of specific constituents in water, based on the maintenance of public health and welfare. Approximately ten potential pollutants associated with thermal EOR operations are covered under the "Quality Criteria for Water".

3.1.2 Safe Drinking Water Act (SDWA)

The Safe Drinking Water Act (P.L. 93-523) requires EPA to promulgate national primary drinking water regulations applicable to public water systems, specifying maximum safe contaminant levels. However, these regulations are subject to future revisions. EPA must decree national secondary drinking water regulations specifying the maximum permissible level of contaminants which may affect the odor or appearance of drinking water. Under the act, the states have the primary enforcement responsibility, although the state regulations must not be less stringent than those set at national standards.

The SDWA has two primary objectives:

- Protection of public water supply systems, and
- Protection of underground drinking water sources.

To accomplish these objectives, EPA has established:

- National Interim Primary Drinking Water Regulations, and
- State Underground Injection Control Program Regulations.

The National Interim Primary Drinking Water Regulations establish maximum contaminant levels for possible physical, chemical, microbiological, and radiological pollutants in public water systems. These regulations became effective on June 24, 1977 and are the standards by which all public water supplies are judged.

The Underground Injection Control Program Regulations of SDWA require the states to establish minimum requirements for effective programs to prevent underground injection activities which endanger drinking water resources. On September 23, 1977, EPA sent to the states for review the proposed regulations for State Underground Injection Control Programs containing requirements applicable to injection wells related to oil and gas production. The regulations

establish, as minimum requirements, the monitoring and reporting of, among other items:

- Anticipated maximum daily volume of injection substances,
- Maximum injection pressure, and
- Type, source, and characteristics of the injection fluid.

3.1.3 Toxic Substances Control Act (TSCA)

The Toxic Substances Control Act (P.L. 94-469) empowers EPA to protect the environment from potential harmful chemical substances which may present an unreasonable risk of injury to human health. The act requires that persons who manufacture or process such chemical substances, conduct tests so that their effect upon health and the environment can be evaluated. EPA is responsible for determining and listing the chemicals subject to testing requirements and sets the standards for the tests.

Although the thermal EOR operations in this context do not specifically deal with manufacturing or processing of chemical substances, this act does affect thermal EOR operations indirectly, since these chemicals may have the impact on the recovery and price of heavy oils.

3.1.4 USGS NTL-2B

These regulations govern the handling, storage, and disposal practices of wastewaters produced from thermal EOR fields located on federal and Indian-lease lands. The regulations required that by October 1, 1977, the wastewaters produced in oil and gas recovery operations be disposed of only by:

- Subsurface injection,
- Impoundment in lined pits, or
- Other acceptable methods.

Stringent limitations are placed upon the disposal of produced water in unlined pits and basic monitoring requirements for disposal to both lined and unlined pits are established. Monitoring activities for water impounded in lined pits are to include daily measurement of chlorides, sulfates, and other constituents which are potentially toxic to animal, plant, and aquatic life.

3.1.5 Spill Prevention Regulations

EPA has established regulations to prevent the discharge of oil and oil products into or upon the navigable water of the U.S. or the adjoining shorelines. The regulations require the development of a spill prevention control and a countermeasure plan involving the construction of dikes, berms, culverts, weirs, and other engineered structures, as necessary, to contain a postulated, accidental spill of oil or oil-regulated substances. Inasmuch as thermal EOR operations are concerned, the practices of onsite mixing or storage of oil-related substances will be affected by these regulations. In order to ensure compliance with these regulations, surface water monitoring during rainstorms as well as during and immediately following any discharge of retained waters into surface water bodies is required.

3.2 CALIFORNIA WATER QUALITY REGULATIONS

In order to operate steam generation EOR equipment in California, it is necessary to obtain permits from the Division of Oil and Gas and/or the Regional Water Quality Control Board. As will be discussed below, the regional boards are involved in the permit process if the wastewater associated with the EOR process is not to be reinjected in the well.

3.2.1 Regional Water Quality Control Boards and the National Pollutant Discharge Elimination System (NPDES) Permits

The requirement for wastewater discharge permits comes as a result of the Federal Water Pollution Control Act (P.L. 92-500). The State of California is responsible for compliance with the act. Through a framework of statewide coordination and policy, nine Regional Water Quality Control Boards (RWQCB's) effectively administer state water quality laws and regulations in compliance with the Federal Water Pollution Control Act. (These are illustrated in Exhibit 3-1, which shows the geographic location of each region.)

The state's Porter-Cologne Water Quality Control Act authorizes the RWQCB's to act in behalf of the state to assure compliance with all water quality laws and regulations. This authority has been delegated by the EPA to the State of California; thus, dischargers do not need to obtain a permit from the EPA. The EPA acts as an overseer, however, in the issuance of any permits by any regional board. This means that permits issued are subject to the EPA's comments and might be further conditioned by them.

The regional boards essentially prohibit the discharge of wastewater from steam generators to surface waters. With this avenue of discharge prohibited, this leaves two alternatives open to dischargers; reinjection in the same well formation, or discharge into sumps, dry stream channels, holding ponds, etc. If reinjection is to be used, the permit review process is then handled by the Division of Oil and Gas. The regional board will then be involved to the extent that they will comment upon DOG's action. However, a permit from the regional board is not necessary if reinjection is done.

There may be instances when an operator may wish to discharge into a percolation pond or dry-stream channel. In such situations, a permit from the regional board will be required. In general, discharges to these types of ponds or channels are allowed only when the

Figure 3-1. California Regional Water Quality Control Boards

groundwater quality is of poor quality already. In essence, the role of the regional board is to insure that such discharges are in compliance with an area's "groundwater objectives". Each regional board is responsible for developing a water quality plan. Such plans set guidelines for the protection of water quality in all areas of each region. Thus, for each subregional area, a guideline is established for meeting water quality and groundwater quality objectives. In determining the effluent limits for a particular area, the regional board utilizes a case-by-case approach.

The board examines the groundwater quality of the area and determines effluent limits which insure that the groundwater quality objectives for the area are met. Thus, such limits vary from field to field.

3.2.1.1 Region III (Monterey, San Luis Obispo Counties)

In this region, all wastewater is reinjected into the well formation. There is considerable potential for groundwater contamination in this area, since there is an abundance of freshwater aquifers, and the well formations are quite shallow.

3.2.1.2 Region V (Fresno, Kern Counties)

In the central Kern County area near Bakersfield (Kern River Oil Field and surrounding fields), discharge to percolation ponds is prohibited due to the abundance of freshwater aquifers. In western Kern County, however, discharge to percolation ponds is allowed in various fields. Effluent limits vary, however, from field to field. In some areas, such as the Midway-Sunset Oil Field, the groundwater quality is so poor that no effluent limits are set for the discharge water. However, in other areas, such as the Anticline Region, effluent limitations are determined. As mentioned above, such determinations are made on a case-by-case basis, and are dependent on the groundwater quality in each area.

3.2.1.3 Region VIII (Orange County)

As discussed above, effluent limitations for discharges into percolation ponds are established on a case-by-case basis. Since the majority of steam generation activity in this area is centered in the Yorba Linda area; however, the effluent limitation for the area was obtained and is presented here.

Effluent Limitation for Yorba Linda Field:

TDS: 830 mg/l

3.2.2 Compliance Requirements of EOR Operations with the Division of Oil and Gas

In most cases, operators of steam generators discharge the wastewater via underground injection to the same well formation that the water came from. Such reinjection operations are subject to permit requirements from the Division of Oil and Gas. No NPDES permit is required. The regional board's involvement would be limited then to a concurrent review with the Division of Oil and Gas to insure that no damage to groundwater would occur, as well as reviewing an injection plan's proposed monitoring system.

The DOG bases approval of reinjection on whether the groundwater table will be contaminated or not. This determination is based on the quality of the water to be discharged, and the quality of the water in the aquifer which will receive the discharge. If the water in the receiving aquifer is of comparable or worse quality than the water to be discharged, then there is no contamination danger, and discharge would be allowed. If this is not the case, then reinjection would not be allowed. In such cases, an aquifer with comparable or worse water quality would have to be located to allow discharge.

In cases where scrubbers for SO₂ removal are used, the scrubber water may pose problems in being reinjected. This is because that

scrubber water is generally of much worse quality than the aquifer from which the process water originally comes. It may be possible to locate an aquifer with worse or comparable water quality as the scrubber water, which is frequently done in San Luis Obispo County. But in other areas, such aquifers may be extremely deep and reinjection may not be mechanically feasible. Hauling of the scrubber waste is an option that is practiced in Kern County. To a lesser extent, scrubber waste is discharged to lined holding ponds. However, this creates problems, as the volume of such waste is great.

In applying for permits from the DOG for reinjection, the following information is required to be submitted:

- (a) An engineering study which includes:
 - (1) Purpose of project
 - (2) Reservoir characteristics of each injection zone
 - (3) Reservoir fluid data for each injection zone
 - (4) Casing diagrams of all idle, abandoned, or deeper-zone producing wells within the area affected by the project
 - (5) The planned well-drilling and abandonment program to complete the project
- (b) A geologic study which includes:
 - (1) Structural contour map
 - (2) Isopach map of each injection zone
 - (3) Geologic cross-section through at least one injection well in project area
 - (4) Representative electric log to a depth below the deepest producing zone
- (c) An injection plan which includes:
 - (1) Map showing injection facilities

- (2) Maximum anticipated surface injection pressure
 - (3) Monitoring system to insure that there is no leakage of injection fluid to other zones
 - (4) Method of injection
 - (5) List of proposed cathodic protection measures for plant, lines, and wells
 - (6) Treatment of water to be injected
 - (7) Source and analysis of the injection liquid
 - (8) Location and depth of each water-source well to be used
- (d) Copies of letters of notification sent to offset operators
 - (e) Other data as required for large, unusual, or hazardous projects
 - (f) All maps, diagrams, etc. are to be labeled to identify wells, boundaries, zones, etc.

The DOG does not specifically list water criteria requirements, except as stated in (c) (7) in which the injection liquid is to be analyzed and (a) (3) which requires the fluid zone liquid to be analyzed. Like the regional boards, approvals or disapprovals will be made on a case-by-case basis. Monitoring is required to show that there is no leakage outside of the injection zone, and that the water quality characteristics of the injection liquid do not exceed the limits imposed by DOG. Such limits would be based on the initial water quality analysis of the injection liquid, and would be imposed to insure that the operator does not discharge liquids of worse quality than the aquifer which is receiving it.

3.3 WATER QUALITY EFFECTS OF EOR OPERATIONS

The two most significant potential causes of water quality deterioration associated with tertiary oil recovery methods are:

- (1) spills of chemicals as a result of transportation and handling,

and (2) improper disposal of chemically-loaded produced water. These sources are difficult to control by regulation.

Of particular importance also are the large volumes of fresh water from existing or potential water supplies which may be required to carry out large-scale projects. Considerable volumes are used for steam displacement projects and to a greater extent for chemical methods of oil recovery such as micellar-polymer flooding. Thus, impacts on water supplies may occur due to local shortages or encroachment of salt water into some aquifers.

California is an area where water use is high and supplies are short. Severe shortages are predicted by the year 2000. The extent of hydrologic environmental effects will depend mainly upon the characteristics and previous development of a reservoir.

Chemical methods of EOR have the greatest potential of adverse impacts on surface water resources because of the large amounts of water consumed and also because spills or concentrated chemicals would be environmentally more detrimental to water supplies than spills or emissions from other EOR processes.

The potential for groundwater contamination resulting from fluid injections associated with EOR operations appears to be minimal. This is based on the lack of groundwater contamination problems associated with conventional waterfloods. Since EOR injection operations are basically the same as waterfloods, an increase in the rate of groundwater contamination is not expected. Also, since the injection fluids associated with micellar-polymer flooding are more costly than water used in waterfloods, it is expected that operators could be expected to take additional precautions to prevent loss of these fluids during the EOR process.

Exhibit 3-2 summarizes the chemical content of a typical waste stream consisting of used scrubber water and process water associated with thermal operations.* Data relating to *in situ* processes are not available at this time.

Exhibit 3-2 Typical Chemical Composition of Wastewaters
From Steam Generators

Constituent		Concentration (ppm)
Boron	(B)	20.8
Calcium	(Ca)	11.2
Magnesium	(Mg)	0.43
Sodium	(Na)	53,000
Potassium	(K)	101
Carbonate	(CO ₃)	0
Bicarbonate	(HCO ₃)	31,183
Chloride	(Cl)	2,237.3
Sulfate	(SO ₄)	79,013
Nitrate	(NO ₃)	0.5
Flouride	(F)	5.2
Iron	(Fe)	32.0
Copper	(Cu)	0.5
Manganese	(Mn)	0.63
Zinc	(Zn)	5.3
Aluminum	(Al)	0.4
Sulfur Dioxide	(SO ₂)	420
Total Dissolved Solids	(TDS)	148,438
Phosphate	(PO ₄)	0.6

*From September 8, 1977 source test on Getty unit in Kern River conducted by BC Laboratories, Inc.

4. NOISE QUALITY REGULATIONS IMPACTING THERMAL EOR OPERATIONS

4.1 U.S. NOISE CONTROL ACT

The Noise Control Act of 1972 (P.L. 92-574) authorized EPA to establish noise emission standards for products distributed in commerce in order to protect the public from inadequately controlled noise sources. EPA's first priority was to issue regulations setting standards for major sources of noise. From the viewpoint of EOR operations, this includes construction, transportation, motors, engines, and other similar equipment. These regulations include limits on noise emissions from such products, taking into account the magnitude and conditions of use, either alone or in combination with other noise sources. Also considered is the degree of noise reduction achievable through the application of the best available control technology and the cost of compliance.

Since most thermal EOR sites are located in rural areas, noise emissions from equipment utilized is not a major environmental issue of concern. In general, the federal requirements define the permitted noise levels in terms of property line standards. Legal noise limits vary as a function of receiving property use. For example, a thermal EOR project operating in a residential area would be prohibited from emitting sound levels greater than 55 dB. If the same project, however, were located contiguous to an industrial park, it might be allowed to emit noise levels as high as 65 dB. The rural nature of most thermal projects mitigates the saliency of a noise constraint to operations.

4.2 STATE REQUIREMENTS

Noise emissions are not a major area of concern in thermal operations. Currently, the State of California works with EPA in formulating noise legislation. It makes recommendations to the local authorities

who are, in turn, responsible for modifying or enforcing the noise statutes within their jurisdictions. The role played by the State of California in controlling noise levels from thermal EOR sites is, therefore, considered nominal.

5. WASTE MANAGEMENT REGULATIONS IMPACTING THERMAL EOR OPERATIONS

5.1 RESOURCE CONSERVATION AND RECOVERY ACT

Included among the objectives of the Resource Conservation and Recovery Act (RECRA) of 1976 are the provisions for the safe disposal of discarded materials and the regulations for the management of hazardous wastes. The Resource Conservation and Recovery Act completely replaced the old Solid Waste Disposal Act. As a result of the Clean Air Act, the Water Pollution Control Act, and other federal and state laws protecting the environment, another problem was created in that greater amounts of solid waste were being generated. The act required EPA to prepare guidelines for the effective management of solid waste. This required a description of the economic and technical levels of performance that can be achieved by various solid waste management practices. Included within the definition of "solid waste" from the thermal EOR fields are the discarded materials in solid, liquid, semi-solid or gaseous form. At a minimum, disposal practices for such wastes are to be such as to protect public health and welfare and prevent deterioration as required by other federal laws. This includes protection of the quality of ground and surface waters from leachates and runoff, protection of the ambient air quality, disease and vector control, safety, and esthetics. Many states had implemented their own solid waste programs as a result of EPA guidelines.

5.2 STATE REQUIREMENTS

The waste management regulations under the California Water Resources Board follow Title 23, Chapter 3, Subchapter 15 which governs land waste disposal requirements. These regulations establish a statewide disposal site and waste classification system. The classification of disposal sites is based upon the geologic and hydrologic features of

the disposal area and the capability for protection of surface and groundwater quality.

The wastes from thermal EOR sites in the State of California can be categorized into two types:

- (1) Nonhazardous wastes
- (2) Hazardous wastes (industrial origin)

The former category includes wastes such as construction and demolition materials, abandoned equipment, rubbish, garbage, etc. The latter category includes the following:

- Brines from the oil fields
- Spent-cleaning fluids; spent-washing fluids
- Chemicals, acids, alkalies, phenols
- Petroleum fractions, rotary drilling muds
- Dewatered sludges; scrubber wastes

The nonhazardous wastes from thermal EOR sites are generally designated to be disposed of in Class II disposal sites within Kern County and are not of much environmental concern.

The hazardous wastes, on the other hand, are generally designated to Class I disposal sites and complete protection is required for the quality of ground and surface waters. Class I sites throughout the states are certified by the State Water Quality Control Boards. As specified by the State Water Resource Control Board, there must be no possibility of discharge of pollutant substances to usable waters. Usable groundwater may underlie the site, but only under extreme cases and where natural geological conditions prevent movement of the wastes to the water and provide protection for the active life of the site. All runoff from Class I waste disposal sites must be contained.

The enforcement of California laws relating to Type 2 (hazardous) wastes and Class I sites fall under the jurisdiction of the California Department of Public Health and the State Water Resources Control Board.

According to the State Health and Safety Code, Section 25100-25185, the State Department of Public Health is required to adopt regulations for the handling, processing, and disposal of hazardous wastes to protect against hazards to the public health, to domestic livestock, and to wildlife. It is unlawful to dispose of any such waste except as provided for in such regulations. The California Administrative Code and the State Water Code give the Water Resources Control Board the authority to specify the particular manner by which a solid waste disposal site shall meet waste discharge requirements which relate to the protection of surface and groundwater quality. There are 12 Class I disposal sites in the State of California. Most of the sites are located in the San Francisco Bay Area, the metropolitan Los Angeles, and the San Diego areas. The locations and parameters of these disposal sites are displayed in Exhibit 5-1.

Exhibit 5-1. Class I Disposal Site Data - California 1974

Disposal Site (Name)	Class I Area (Acres)	Age of Site (Years)	Class I Lifespan Left (Years)	Approximate Volumes of Liquid Wastes Handled (Gal/Month)
Big Blue Hills	32	1	20	NA*
Calabasas	290	14	35	740,000
Hollister	60	7	10	-
Hunter	150	1-1/2	Indef.	1,000,000
J&J	278	5	50	2,300,000
Martinez (Sites 1 & 2)**	#1 - 20 #2 - 130	#1 - 20 #2 - 3	#1 - 5 #2 - 10	4,000,000
Omar	5	15	20	200,000
Otay	10	14	12	87,000
Palos Verdes	61	17	3	6,700,000
Simi Valley	87	5	12	400,000
West Contra Costa	18.5	19	76	900,000
West Covina	80	10	30	4,000,000

*Approximately 200 cubic yards per day of empty containers

**Site #1 is Vine Hill; Site #2 is Baker.

6. TYPICAL CASE ENVIRONMENTAL STUDY

6.1 GENERAL

The following chapter defines the environmental issues confronted by operators of prototypical thermal EOR production fields. The range of potential emissions/effluents are identified and separate analyses are conducted for the environmental parameters of air quality, water use, noise control, and waste management. Each of these parameters has been analyzed under the project developmental phases of site preparation and field testing.

The techniques utilized in this chapter mirror those applied in the Environmental Impact Assessment (EIA); a document required for governmental approval prior to the commencement of a thermal project. Federal, state, and local environmental regulations are discussed for a typical field with an area of approximately 4000 acres. The assumed field parameters are shown in Exhibit 6-1.

6.2 AIR QUALITY

Typical air emissions for site preparation and field testing activities are described in the following two subsections.

6.2.1 Site Preparation Activities

All reservoirs targeted in this have produced heavy oil before and most are currently active under primary or secondary recovery operations. Therefore, typically there would be only a minimal amount of drilling and associated work necessary to ready the field for thermal operations. However, such activity which consists primarily of working over existing production and injection wells and drilling observation wells is time consuming. The completion of the site preparation phase usually requires close to two years.

Exhibit 6-1. Typical Thermal EOR Reservoir Data

Parameter	Measurement Unit
Field Area	4000 Acres
Depth	1000 Feet
Porosity	20 Percent
Permeability	1000 Millidarcies
Oil Gravity	12° API
Oil Saturation	1500 Bbl/acre/foot
Steam Generator Density	2.5 MMBtu/hr/acre
Thickness	75 Feet
Total Number of Existing Wells (Injectors and Producers) in 2000 Acres:	
<u>First One-Half of Field - 8-Acre, 5-Spot Patterns</u>	610
• Injector Wells in 8-Acre Pattern	250
• Producer Wells in 8-Acre Pattern	360
<u>Second One-Half of Field - 20-Acre, 5-Spot Pattern</u>	244
• Injector Wells in 20-Acre Pattern	100
• Producer Wells in 20-Acre Pattern	144
Total Number of Observation Wells to be Drilled	500
Grand Total Number of Wells (Injectors, Producers, and Observation Wells)	1354
Total Number of 20 MMBtu/hr Steam Generators Required	250
Total Number of 50 MMBtu/hr Steam Generators Required	100

Air emissions evidenced during site preparation facilities consist primarily of carbon monoxide, hydrocarbons, nitrogen dioxide, sulfur dioxide, and suspended particulates. In addition, uncontrolled fugitive dust emissions occur in areas of land disturbance caused by drilling, bulldozing, etc. Such emissions occur roughly at the rate of five tons/acre/month. The actual magnitude of the fugitive dust emissions depend upon the time of year, the methods of construction employed, the actual size of the area disturbed, and the type of control measure utilized. Exhibit 6-2 estimates the uncontrolled emissions from all equipment employed in the field during the site preparation phase.

6.2.2 Field Test Activities

This section will discuss air pollutant emissions generated from typical thermal EOR operations during field operations. Specifically, these emissions are from (1) steam generators, (2) internal combustion compressors for *in situ* combustion, and (3) emissions of off-gases from the wellheads.

The only significant emissions to the atmosphere from the steam generation and combustion equipment in normal operation are those resulting from the combustion of fossil fuels. The steam generators under consideration are classified as water-tube type boilers. Water-tube boilers are of simple box construction, using tubing to circulate water and steam. Fluid is heated under pressure in a coil heat exchanger and flashed into steam in an external chamber. These relatively small, controlled-circulation boilers are capable of producing steam within minutes after a cold start.

The majority of EOR operations in California are steam oriented. Most of the steam generators used in California are in the 50 MMBtu/hr heat input size range. The bulk of steam generation activity occurs in Kern and Fresno Counties. Other counties in which enhanced oil recovery

Exhibit 6-2. Estimated Air Emissions from a Typical Thermal EOR Field During Site Preparation Activities

Activity	Equipment	Operating Time	Total Time (hours)	Emission Factors/gm/hp-hr (Diesel Engines)					Emission Factors, lb/hr (Heavy Duty Equipment)				
				Estimated Emissions, Tons					Estimated Emissions, Tons				
				CO	HC	NO ₂	SO ₂	TSP	CO	HC	NO ₂	SO ₂	TSP
Working over existing injection and production wells	350 hp diesel engine to operate rig	100 hrs/well	85,400	3.03	1.12	14.0	0.93	1.0	-	-	-	-	-
				99.74	36.87	460.88	30.62	32.92					
Drilling observation wells	250 hp diesel engine to operate auger drill	3 hrs/well	1,500	3.03	1.12	14.0	0.93	1.0	-	-	-	-	-
				1.25	0.46	5.74	0.38	0.41					
Site preparation*	Dozers (3)	500 hrs/dozer	1,500	-	-	-	-	-	0.74	0.24	5.05	0.35	0.16
									0.56	0.18	3.80	0.26	0.12
	Loaders (4)	500 hrs/loader	2,000	-	-	-	-	-	1.56	0.19	2.40	0.18	0.17
									1.56	0.19	2.40	0.18	0.17
	Tractors (4)	400 hrs/tractor	1,600	-	-	-	-	-	2.15	0.15	0.99	0.09	0.14
									1.72	0.12	0.80	0.07	0.11
Transportation of material and equipment	Heavy duty trucks (10)	1500 hrs/truck	15,000	-	-	-	-	-	1.80	0.30	2.96	-	-
									13.50	2.25	22.20	-	-
General	Miscellaneous	400 hours	4,000	-	-	-	-	-	0.41	0.16	2.3	0.14	0.14
									0.82	0.32	4.60	0.28	0.28

*Minimal site preparation activities will take place because of the developed status of the oil fields.

utilizing steam occurs are Monterey, Santa Barbara, and to a lesser extent San Luis Obispo, San Diego, Orange, and Los Angeles.

In situ operations use internal combustion engines to pump air into the wells to support a spontaneous combustion reaction. In California, this type of operation is scarcely used. At present, two companies, Chanslor-Western Oil and Development and Gulf Oil and Minerals, are involved on a small scale with *in situ* processes in Kern County.

6.2.2.1 Emissions Due to Steam Injection Operations

Emissions from steam generators have been estimated based upon the assumption that all units in the field consist of oil-fired generators. The physical characteristics of generators commonly utilized in steaming operations are described in Exhibit 6-3. Such generators produce three major pollutants of interest: sulfur dioxide, nitric oxide, and particulates. Additionally, small amounts of unburned hydrocarbons and traces of carbon monoxide are also emitted. The onsite storage tanks and the wells to be steamed also emit hydrocarbons.

- (a) Sulfur Dioxide (SO₂) is produced by the combustion of fuel containing sulfur and sulfur compounds. The fuel containing 1.1 percent sulfur by weight results in 7.5 pounds of SO₂ per barrel of fuel burned.* This result is in good agreement with measured SO₂ emissions obtained during a recent test of a Chevron USA generator burning 1.1 percent sulfur fuel in the Kern River field. The total emissions reported for SO_x (taken as SO₂) ranged from 58-63 lbs/hr. Using the upper value and a fuel consumption rate of 210 bbl/day, one obtains an SO₂ production rate of 7.2 lbs/bbl. A recent source test conducted by the Chanslor-Western Oil and Development Corp. (CWOD) provides an average measured sulfur dioxide emission rate of 7 lbs/bbl for fuel containing 1.15 percent SO₂. The National Enforcement Investigations Center (NEIC) estimates the SO₂ emission factor at 6.6 x (percent sulfur by weight). The sulfur content of the produced crude oil of the various operators in California varies from 0.5 percent to 4.0 percent.

*342 lbs/bbl x 1.1%(S) = 3.76 lbs/bbl(S) = 7.5 lbs/bbl (SO₂).

Exhibit 6-3. Physical Generator Characteristics

Type	Approximate Rated Output (10 ⁶ Btu/Hr)	Stack Height (m)	Equivalent Stack Diameter (m)	Exit Velocity (m/sec)	Temperature (C)
1	5	6.71	0.61	4.28	260
2	10	3.83	1.54	2.32	260
3	20	3.96	1.54	2.32	260
4	50	6.71	1.54	5.73	260

- (b) Nitric Oxide (NO) is produced by the high temperature combustion of the fuel. While there are no standards for NO, there are standards for nitrogen dioxide (NO₂) which is produced by chemical reactions in the atmosphere. The reaction chain is similar to the photochemical reactions which produce smog. The conversion of NO to NO₂ depends on the concentrations of other secondary pollutants as well as on available sunlight. Eventually 100 percent of the NO converts to NO₂. The 100 percent factor is assumed in predicting annual NO₂ averages.

Recent source test data obtained by CWOD for NO₂ emissions from their steam generators show typical emission rates for their "50's" and "20's" of 2.2 and 2.9 pounds respectively of NO₂ per barrel of fuel burned. The nitrogen content of the fuel used in the source tests was 0.68 percent. AP-42 suggests an NO_x (taken as NO₂) emission rate of 5.04 lbs/bbl for fuel with that level of nitrogen. This value is not supported by CWOD's test data. NO₂ emissions data measured by Getty Oil Company also do not support the AP-42 value. The NO_x emission rate is heavily dependent on the excess oxygen present during combustion and the temperature of combustion. Most of the oil-fired units in California have similar operating characteristics. The mid-range of CWOD's measured NO₂ emission rates of 2.5 lbs/bbl provides a realistic estimate of the NO₂ emissions.

- (c) Particulates - An estimate of the total amount of particulate matter emitted was provided by measurements of Chevron USA generators and data provided by Getty Oil. All of the units are considered to have similar particulate emissions. Both sources show particulate emission rates of 0.5 lb/bbl of fuel burned; however, the particulate emission factor derived by NEIC for the crude-fired generators is 0.7 lb/bbl, resulting in the calculated values of particulate concentrations comprising 28 percent of the calculated NO₂ concentrations.
- (d) Hydrocarbons - are produced by (1) combustion of fuel in the steam generators, (2) evaporative breathing and working losses from associated storage tanks, and (3) from the wells to be steamed, after the steam is vented to the atmosphere.

Source test data on Chevron and Getty Oil Company steam generators show approximately 0.1 lb/bbl hydrocarbon (HC) emissions, or about 4 percent of the NO₂ emission rate. This value is considered typical for all of the various sources.

Evaporative breathing and working losses associated with the storage tanks can be calculated using equations contained in EPA's AP-42 and are based on tank type, diameter, vapor pressure of liquid stored, height of vapor space, the daily ambient temperature change and the daily throughput. HC emissions from these sources are negligible due to their small volumes and low vapor pressure of the liquid stored.

Major emissions of hydrocarbons occur from the wells which are steamed when the hydrocarbon-laden steam is vented to the atmosphere. There are two types of wells associated with steam operations. One type is termed a "displacement" well. In this type of operation, steam is injected into the well on a continuous basis. The steam acts to heat the oil, and also to "displace" it through pressure and volume. The other type is termed a "cyclically-steamed" well. This involves injecting steam into a well, and leaving it there for a period of days. The steam then remains in place to heat the oil, which is pumped to the surface. After a number of days, the steam is vented to the atmosphere and the process is repeated. This type of operation is also referred to as "huff and puff".

Based on source tests on existing steam displacement wells by the Getty Oil Company, an emission factor of 252 lbs/day/well has been established. This figure is used by the EPA in determining the hydrocarbon emissions resulting from steam-flooding operations.

In arriving at a hydrocarbon emission factor from cyclic or huff-and-puff wells, it is assumed that the steaming operations involved are a fraction of that required for the steam flooding. Getty Oil has estimated that the time of steam-in-place for cyclic wells is approximately 5 percent of the time of steam-in-place for displacement wells. Thus, an emission factor of 12.6 lbs/day/well is used to calculate hydrocarbon emissions from cyclically-steamed wells. ($252 \text{ lb/day/well} \times .05 = 12.6 \text{ lb/day/well}$).

It is recognized by EPA that hydrocarbon emissions from wells vary from field to field, and that the factor for cyclic wells could vary considerably due to variability of time of steam-in-place. At this time, however, these are the only figures that are available. The California Air Resources Board is currently conducting a study of hydrocarbon emissions from tertiary oil operations. Results from this study are expected to be released in approximately four to five months.

- (e) Minor Emissions - Source test data on Chevron and Getty Oil Company steam generators show approximately 0.02 lb/bbl of carbon monoxide (CO) which is about 0.8 percent of the NO₂ emission rate. This value is considered typical for all of the various sources.

6.2.2.1.1 Typical Generator Emission Rate Summary

As is apparent from the above discussion, the major emissions of interest from steam injection operations are sulfur dioxide, nitrogen dioxide, and particulates. Among these, sulfur dioxide is of critical concern because of the stringent national, state, and local regulations limiting its legal emission level. Exhibit 6-4 lists the typical emission rates for all pollutants expected for the various sizes of generators listed in Exhibit 6-3. For this computation, it is assumed that the steam generator will use a fuel containing 1.09 percent sulfur by weight.

6.2.2.2 Emissions Due to *In Situ* Combustion Operations

In situ combustion is accomplished by driving air down into a well to support a spontaneous combustion reaction. The equipment utilized are generally internal combustion engines which are fired by diesel fuel. In some limited instances, natural gas-fired turbines may be used. The pollutants involved with the *in situ* process emanate from the compressors themselves and from the off-gases generated at the wellheads.

6.2.2.2.1 Typical Equipment Emissions

The emission characteristics of internal combustion engines and natural gas-fired turbines have been determined by using emission factors provided by EPA's Publication AP-42, Chapters 3.3.2 and 3.3.3. Since diesel is the most commonly used fuel for the internal combustion units, the factors presented in this section are based on its use. The diesel-fired units produce relatively small emissions with the

Exhibit 6-4. Typical Emissions from an Oil-Fired Steam Generator

Approximate Rated Output (10 ⁶ Btu/hr)	Typical Daily Fuel Consumption (bbl/day)	Typical Yearly Operating Schedule (days)	Emissions (lb/bbl fuel)				Emissions (tons/year)			
			SO ₂ [*]	NO ₂	Particulate	HCl	SO ₂ [*]	NO ₂	Particulate	HCl
5	16	365	7.2	2.5	0.7	0.1	21	10.3	2.9	0.43
10	50	292	7.2	2.5	0.7	0.1	52.6	18.3	5.1	0.73
20	115	292	7.2	2.5	0.7	0.1	120.9	42	11.8	1.68
50	210	292	7.2	2.5	0.7	0.1	220	76.7	21.5	3.07

*Assuming use of fuel containing 1.09 percent sulfur by weight.

largest emissions being nitrogen dioxide. The turbines, however, produce large emissions of NO₂. Exhibits 6-5 and 6-6 list the typical emission rates for all pollutants expected for internal combustion engines and natural gas-fired turbines.

6.2.2.2.2 Typical Well Emissions

During the fireflood process, the high temperatures which result in the oil reservoir enable a number of chemical reactions to occur. These compounds, as well as the combustion residues, may be present in the emissions at production wells. Others may be confined in the reservoir after the process is completed.

Based on a sample of 31 *in situ* sources in a study commissioned by the EPA, an analysis of the major constituents of the produced gas has been made. Exhibit 6-7 presents an estimate of the volumes of constituent gases produced per barrel of oil produced. Regional differences in the operating and reservoir characteristics of *in situ* combustion projects would affect the emissions produced. The chemical and physical process of combustion within an oil-bearing stratum are complex and the possible environmental effects of combustion products need further study.

In the EPA-commissioned study, it was assumed that most of the sulfur compounds would remain in floodwater or produced water during water-combustion, oil-recovery processes. This is based on the low pH of produced water from projects in the sample. Typical values of pH were 2.7 to 4.0. The gas streams were measured, however, at near optimum operating conditions early in the life of the flood. As the flood progresses, the composition of emissions may change to include oxides of sulfur.

Hydrogen sulfide (H₂S) emissions may result from the hot gases containing hydrogen in the fireflood coming in contact with the sulfur-bearing rocks surrounding the oil pools. However, no H₂S was quantified

Exhibit 6-5. Emissions from Diesel-Powered Internal Combustion Engines

Approximate Rated Output (Hp/Hr)	Typical Yearly Operating Schedule	Emissions (16 Hp/Hr)					Emissions (Tons/Yr)				
		SO ₂	NO ₂	Partic.	HC	CO	SO ₂	NO ₂	Partic.	HC	CO
500	365	.002	.03	.002	.002	.007	4.4	65.7	4.4	4.4	15.3
750	365	.002	.03	.002	.002	.007	6.6	99	6.6	6.6	23
1000	365	.002	.03	.002	.002	.007	8.8	131	8.8	8.8	31

Exhibit 6-6. Emissions from Natural Gas-Fired Turbines

Approximate Rated Output (Hp/Hr)	Typical Yearly Operating Schedule	Emissions (16/10 ³ Hp/Hr)					Emissions (Tons/Yr)				
		SO ₂	NO ₂	Partic.	HC	CO	SO ₂	NO ₂	Partic.	HC	CO
500	365	.004	2.9	NA	.02	1.1	.008	6.3	NA	0.44	2.4
750	365	.004	2.9	NA	.02	1.1	.013	9.5	NA	0.65	3.6
1000	365	.004	2.9	NA	.02	1.1	.017	12.7	NA	0.88	4.8

Exhibit 6-7. Average Emissions of Gaseous Compounds
From *In Situ* Combustion (a) (b)

COMPOUND	EMISSIONS (Standard Cubic Feet Per Barrel of Oil Produced)
Carbon Dioxide	435
Carbon Monoxide	160
Nitrogen and NO _x (c)	4,220
Oxygen	135
Hydrocarbons	150

(a) Assumes all sulfur compounds remain in solution with produced water. However, emissions of SO_x may occur in the late phases of a fireflood.

(b) Based on a survey of the gas streams of 31 firefloods (average value).

(c) Formation of NO_x compounds is not favored at the typical burning temperatures in a fireflood of 700°F to 1,200°F. Most of the emissions would probably be nitrogen.

in the 31 samples mentioned above, nor is there any further data relating to a typical H₂ emissions from a fireflood well.

6.3 WATER USE AND EFFLUENTS

Thermal recovery projects face a number of water-related environmental issues which must be addressed. These issues include:

- (1) Estimated quantities of water required for successful operations, and
- (2) Availability of water and estimated probability of contamination of the local surface and groundwaters by wastewater effluents.

6.3.1 Site Preparation Activities

Water requirements during the site preparation phase of a thermal project are to primarily fulfill the functions of dust control and the provision of drinking and sanitary facilities. Water requirements for dust control depend upon the local rainfall and soil moisture content during the time of construction. The daily water needs per onsite person at a thermal project are estimated to be 20-30 gallons. The wastewater effluents due to site preparational activities are prompted primarily by drilling, well workovers, and similar activities. The potential of detrimentally affecting the surface-water quality of local water bodies exists as a result of stormwater runoff from the field. Runoff from the construction area may include clay and silt particles, inorganic and organic matter from decayed vegetation and soil, oil from paved areas, and oil and grease from construction equipment. Further analysis of this issue requires site-specific details.

6.3.2 Field Test Activities

Many thermal EOR field projects have reported water requirements of as much as 20 bbl/water for every one barrel of oil recovered. The availability of water, therefore, is a very real constraint affecting

the continued development of thermal technologies in some areas. A regional and site water survey is necessary prior to the initiation of any project.

The regulatory requirements for the disposal of wastewater effluents from a typical thermal project can be viewed from two distinct angles:

- (1) The concentrations of certain physical/chemical parameters in the wastewaters are not to exceed a given limit at the point of generation (source) prior to their disposal into the receiving waste bodies.
- (2) The concentrations of certain physical/chemical parameters in the wastewaters at the receiving end (water bodies) are required not to exceed a given limit. A general list of the typical chemical constituents that can be expected in the liquid effluents at the point of generation during various phases of a typical thermal project are shown in Exhibit 6-8 along with the regulatory status of each constituent. On the receiving end, the stream and groundwater quality requirements vary from state to state. Exhibit 3-2 in Section 3 shows the typical chemical composition of wastewaters from steam generators.

The local groundwater quality has the potential to be affected by various operations at the thermal EOR test site. Some of these issues include:

- Potential of seepage of injected or reinjected materials through the formations to penetrate underground aquifers,
- Potential of leaching from unlined waste disposal pits,
- Potential of accidental surface spills during operations, storage, and transport,
- Potential of leaks and breaks during the test operations and during the plugging of the well casings, and
- Potential of secondary fractures which may connect the reservoir with aquifers.

Exhibit 6-8. Typical Constituents in Waste Liquid Effluents From Thermal EOR Fields and Federal Regulatory Status

Activity	Constituent	Regulatory Status
Site Preparation	Natural Organics	None
	Nitrates	(1) NIA
	Phosphates	(1) NIA
	Coliform	None
	Metallics	(2)
	Fuels	None
	Sediments (TSS)	None
Steam Injection	Dissolved Solids (TDS)	None
	Low pH Brine	None
	Toluene	(1) NIA
	Crude Oil	(3)
Sweep Efficiency Improving Agents	Quinoline	(3,4)
	Sodium Hydroxide	(4)
	Toluene	NIA
Trace Elements Present in Heavy Oils Which May Get Liberated During Stimulation Activi- ties	Antimony	(3,4)
	Arsenic	(2) 0.05 mg/l
	Barium	(2) 1.0 mg/l
	Cadmium	(2) 0.01 mg/l
	Chromium	(2) 0.05 mg/l
	Copper	(4) 1.0 mg/l
	Cynide	(2) 5.0 ug/l
	Lead	(2) 0.05 mg/l
	Manganese	(4) 50.0 ug/l
	Mercury	(2) 0.002 mg/l
	Nickel	(4)
	Phenols	(4) 10 ug/l
	Sulfur	(2) 0.05 mg/l
	Tin	(3)
	Vanadium	(3,4)
	Zinc	(4) 5.0 mg/l
Drilling of Disposal Wells (A) Weighting Agents	Barium Sulfate	(2) 1.0 mg/l
	Calcium Carbonate	None
	Siderite	(5) 0.3 mg/l
	Lead Sulfide	(1) NIA

Exhibit 6-8. Typical Constituents in Waste Liquid Effluents From
Thermal EOR Fields and Federal Regulatory Status
(Continued)

Activity	Constituent	Regulatory Status
(B) pH Adjustment	Sodium Hydroxide	(4)
	Sodium Carbonate	None
	Calcium Oxide	(4)
	Calcium Hydroxide	(4)
	Calcium Sulfate	(2) NIA
	Potassium Hydroxide	(3,4)
(C) Fluid Additives	Polyvinyl Acetate	(3)
	Maleic Anhydride	(3)
	Carboxymethyl Copolymers	(3)
	Cellulose	
	Hydroxyethyl Cellulose	None
	Bentonites	(3)
	Attapulgites	(3)
(D) Bactericides	Aldehydes	None
	Chlorinated Phenols	NIA
	Quaternaryamines	None
	Alkyl Amines	(2) NIA
	Texaphone	(4) 5.0 µg/l
	Linear Alkyl Sulfate	None
(E) Corrosion Inhibitors	Arsenite	(2) 0.05 mg/l
	Amines	None
	Imidazolines	(3)
	Dispersant and Thinners	
	(1) Lignosulfonates	(3)
	(2) Phosphoric Acid	(3,4)
	(3) Tannin	(3)
	Xanthonates	(3)
	Lignites	None
	Acrylates	None
	Acrylamides	(3)
	Asphalt	(3)

- Notes: (1) NIA - No information available.
(2) National Interim Drinking Water Regulations
(P.L. 93-523, P.L. 95-190) EPA, September 1976.
(3) Toxic Substance Control Act (P.L. 94-469), Candidate
List of Chemical Substances, EPA, April 1977.
(4) Proposed Regulations on Designation of Hazardous
Substances (40 F.R. 59960, December 1975) EPA,
December 1975.
(5) Quality Criteria for Water, EPA, July 1976.

6.3.3 Summary

The water availability/quality concerns pertaining to the thermal EOR field testing warrant the resolution of the following issues:

- Quantification of water demands,
- Determination of local water supply and demand situation and resolution of any legal conflicts,
- Identification of alternative supply strategies and development of desalination and recycled water-use methods,
- Definition of chemical characteristics of steam additives,
- Development of a comprehensive package for monitoring the composition of ambient surface and groundwater,
- Development of a matrix for monitoring the waste effluents prior to their disposal, and
- Correction of the existing corrosive conditions in the well casings.

After a careful evaluation of the state requirements for the maintenance of acceptable water quality, a sample criteria list for surface and groundwaters was prepared, as shown in Exhibits 6-9 and 6-10.

6.4 NOISE QUALITY

Based upon the usage of the major pieces of equipment, the noise levels for each of the two project phases in a typical EOR field are described below.

6.4.1 Site Preparation Activities

Activities associated with the drilling of observation wells, working-over of existing wells, and movement of heavy-duty vehicles in the field require operation of several major pieces of equipment. The typical pieces of equipment include crawler tractors, chain saws,

Exhibit 6-9. Typical Surface Water Quality Standards
Enforced by the States

Heavy Metals and Other Compounds	Not to Exceed the Following Concentrations:	
	mg/l	ug/l
Arsenic	0.01	-
Barium	0.50	-
Cadmium	0.01	-
Chromium (Hexavalent)	0.05	-
Lead	0.05	-
Silver	0.05	-
Nitrates	45	-
Chlorides	100	-
Phenol	0.001	-
Cyanide	0.025	-
Flouride	1.0	-
Selenium	0.01	-
Nitrate	8	-
Dissolved Iron	-	1000.0
Mercury	-	0.5
Manganese	-	1000.0
Foaming Agents (MBAS)	0.5	-
Ammonia	1.5	-

Exhibit 6-10. Typical Groundwater Quality Standards
Enforced by the States

Parameter	Constituents
Tastes and Odors	Groundwaters shall not contain taste- or odor-producing substances in concentrations that cause nuisance or adversely affect beneficial uses.
Coliform	In groundwaters used for domestic or municipal supply, the concentration of coliform organisms over any 7-day period shall not exceed a median of 2.2/100 ml.
Radioactivity	Groundwaters used for domestic or municipal supply shall not contain concentrations of radionuclides in excess of the limits specified.
Chemical Constituents (TDS, Cl, SO ₄ , B, Na, N)	Groundwaters used for domestic or municipal supply shall not contain concentrations of chemical constituents in excess of the limits specified (by the jurisdiction).

air compressors, diesel generators, motor pumps, and heavy trucks. The regulatory requirements call for compliance with the employee oriented OSHA regulations as well as EPA's ambient noise quality criteria. In the former case, the workers at the federal facilities are required to use earplugs while working in an environment where noise levels exceed 85 dB. In the latter case, EPA requires the ambient noise levels due to the operation of one or more pieces of equipment not to exceed a given value. This value depends upon demographic characteristics of the land surrounding the EOR site.

6.4.2 Field Test Activities

The noise levels associated with the field testing activities are primarily the result of the operation of steam generators or air compressors. Both of these noise sources normally operate on a continuous basis. Noise emissions must meet the same standards as those imposed on site preparation activities described in Section 6.4.1.

6.4.3 Summary

Since most of the thermal EOR fields are located in rural areas, compliance with noise requirements is not considered a major environmental issue.

6.5 WASTE MANAGEMENT

The waste loads that are generated from a typical thermal EOR field can be classified into the two activity-oriented categories of site preparation and field testing.

6.5.1 Site Preparation Activities

The wastes produced from the site preparation activities are similar to those from the conventional oil recovery operations and consist of:

- Clay, silt, and dust particles
- Organic and inorganic matter from decayed vegetation and soil
- Drilling wastes such as mud, brines, etc.
- Oil and grease from construction machinery.

The first two types of wastes are usually disposed of by landfill and are not of much environmental concern. The brines, however, are required to be disposed of either onsite or in the state-approved sites. Likewise, the drilling mud, because of the potential damage to local water and life systems, requires careful handling.

6.5.2 Field Test Activities

The wastes generated from the field operation activities consist of the following:

- Sludge produced from scrubbers
- Spent liquids such as scrubber fluids
- Employee-generated wastes
- Oily wastes, oil from paved areas, etc.
- Hazardous (toxic) wastes.

These wastes prompt measures for handling and disposal as outlined below:

- The scrubber liquids require onsite treatment prior to the disposal into local surface waters.
- Scrubber sludges are difficult and costly to dispose of and are a potential source of contamination of local surface and groundwaters at the disposal site.
- The employee-generated wastes are usually municipal-type wastes and are handled by conventional means.
- The oily wastes are collected separately and are disposed of according to the local regulatory requirements.
- The hazardous wastes are handled in accordance with the state regulatory requirements.

6.5.3 Summary

In general, the quantities of wastes produced from a typical EOR field are dependent on the following:

- The area of the field
- The capacities of various steam generators and air compressors in the field
- Total number of active steam generators and air compressors in operation
- Characterization of chemicals in liquid effluent and solid waste streams
- Types of fuel burned in various sources of onsite combustion
- The physical/chemical characteristics of the oil formations
- Type of air and water quality control systems employed.

In realistic terms, resolution of any potential waste problems requires site-specific details that must be evaluated against the applicable governmental regulatory requirements.

7. CONCLUSIONS

The environmental requirements for candidate domestic heavy-oil reservoirs were identified, defined, and evaluated from federal, state, and local regulatory viewpoints. Various federal, state, and local environmental agencies were contacted and the desired information obtained. These data were extracted, screened, analyzed, and tabulated. Based upon the analysis performed, the following conclusions are in order:

- The major issues of environmental significance regarding thermal EOR projects are the impacts on ambient air quality, groundwater quality, and process water availability.
- Noise emissions from steam-injection operations, in general, are not considered as potential issues of environmental concern, whereas those from air compressors require special attention.
- Environmental issues such as solid- and liquid waste-handling procedures, land use and disturbances, and ecological and socioeconomic impacts warrant field-oriented details in order to develop an environmental compliance strategy.
- The mitigation measures to be employed at each thermal EOR facility are strictly site specific, thus requiring an assessment of short-term and long-term environmental impacts before the commencement of the project.

ADDENDUM A:

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL
EOR PROCESSES

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
THE CLEAN AIR ACT AND AMENDMENTS (P.L. 95-95)	DECEMBER 1970/AUGUST 1977, MAY 1978	EPA	<ul style="list-style-type: none"> • NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS) HAVE BEEN ESTABLISHED TO REGULATE AMBIENT CONCENTRATIONS OF THE FOLLOWING SEVEN CRITERIA POLLUTANTS: CO, NO₂, TSP, SO₂, HC, O_x, AND LEAD. • NAAQS FOR SUSPENDED SULFATES ARE BEING CONSIDERED. • FOR AREAS WHERE AIR QUALITY IS ALREADY BETTER THAN THAT REQUIRED BY THE NAAQS, PREVENTION OF SIGNIFICANT DETERIORATION (PSD) OF EXISTING AIR QUALITY CRITERIA FOR SO₂ AND TSP HAVE BEEN ESTABLISHED. • PERMITS IN NONATTAINMENT AREAS GOVERNED BY THE EMISSION OFFSET INTERPRETIVE RULING FOR POLLUTANTS GREATER THAN 100 TONS/YEAR MAY REQUIRE OFFSETS AND STIPULATE THAT SOURCES ACHIEVE THE LOWEST ACHIEVABLE EMISSION RATE (LAER) (SEC.2.1.2.1). • PERMITS IN ATTAINMENT AREAS GOVERNED BY THE PSD REGULATIONS FOR STEAM GENERATORS HAVING EMISSIONS GREATER THAN 250 TONS/YEAR MAY REQUIRE USE OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT) AND AIR QUALITY ANALYSIS (SEC. 2.1.1.1). 	<ul style="list-style-type: none"> • BECAUSE OF THE SMALL SIZE OF STEAM BOILERS, EMISSION MONITORING IS NOT REQUIRED BY FEDERAL REGULATIONS BUT IT IS REQUIRED BY STATES. — — • NO EMISSION LIMITS ARE ESTABLISHED FOR THESE SOURCES. HOWEVER, UNDER THE PERMIT PROGRAMS, LAER AND BACT MAY BE REQUIRED AS SPECIFIED BELOW: LAER (2.1.2.1): SO₂: 0.25% IN FUEL OR EQUIVALENT SCRUBBING IS REQUIRED. NO₂: COMBUSTION MODIFICATIONS AND CASE-BY-CASE ANALYSIS IS WARRANTED.

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
<p>THE CLEAN AIR ACT AND AMENDMENTS (Continued)</p> <p>135</p>			<ul style="list-style-type: none"> PSD REGULATIONS FOR CO AND NO₂, HC, AND PHOTO-CHEMICAL OXIDANTS WERE TO BE PROMULGATED BY AUGUST 1979. NEW SOURCE PERFORMANCE STANDARDS (NSPS) GOVERNING ATMOSPHERIC EMISSIONS FROM 26 TYPES OF STATIONARY AIR POLLUTION SOURCES HAVE BEEN ESTABLISHED (SEE EXHIBIT 2-3). 	<p>TSP: CASE-BY-CASE ANALYSIS IS WARRANTED. CO: NOT AS A PROBLEM CONSIDERED WITH STEAM GENERATORS.</p> <p><u>BACT (2.1.1.1)</u> SO₂: 0.5% SULFUR IN FUEL OR EQUIVALENT SCRUBBING IS REQUIRED. NO₂: COMBUSTION MODIFICATIONS AND CASE-BY-CASE ANALYSIS IS WARRANTED.</p> <p>TSP: CASE-BY-CASE ANALYSIS IS REQUIRED. CO: NOT AS A PROBLEM CONSIDERED WITH STEAM GENERATORS. HC: NO TREATMENT FOR GENERATORS REQUIRED. VAPOR RECOVERY ON WELL-HEADS IS WARRANTED.</p> <p>NSPS AND REGULATIONS FOR THE PREVENTION OF SIGNIFICANT DETERIORATION MAY AFFECT THERMAL EOR SITING IN NONATTAINMENT AREAS.</p>

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
<p>THE CLEAN AIR ACT AND AMENDMENTS (Continued)</p>			<ul style="list-style-type: none"> • AREAS WHERE NONATTAINMENT OF NAAQS IS PROJECTED, THE STATES HAVE AN OPTION OF REGULATING EMISSION OFFSET POLICY UNDER WHICH SIGNIFICANT INCREASED EMISSIONS FROM NEW OR EXPANDED SOURCES ARE TO BE COUNTER-BALANCED BY EQUAL OR GREATER REDUCTIONS OF EMISSIONS FROM EXISTING SOURCES BEFORE A PERMIT FOR PROCESS OPERATIONS CAN BE ISSUED. • NEW PROVISIONS OF THE CLEAN AIR ACT ENACTED IN 1977 REQUIRE THE STATES TO REVISE THEIR STATE IMPLEMENTATION PLANS (SIP) FOR ALL AREAS THAT DO NOT ATTAIN NATIONAL AMBIENT AIR QUALITY STANDARDS. • PROVISIONS FOR THE DEVELOPMENT OF NATIONAL EMISSION STANDARDS FOR HAZARDOUS POLLUTANTS REGULATING EMISSIONS OF SPECIFIC SUBSTANCES FROM BOTH NEW AND EXISTING SOURCES ARE ALSO CONTAINED. 	<ul style="list-style-type: none"> • AIR EMISSION TRADEOFFS MAY BE REQUIRED. • THE THERMAL EOR FIELDS WILL BE AFFECTED BY THE SIP, ESPECIALLY WHEN THEY ARE LOCATED IN NONATTAINMENT AREAS. • EMISSION STANDARDS FOR HAZARDOUS POLLUTANTS FROM THERMAL EOR SITES SUCH AS BENZENE, ARSENIC, CADMIUM, VANADIUM, BERYLLIUM, MERCURY, AND POLYCYCLIC ORGANIC MATERIALS HAVE EITHER BEEN DEVELOPED OR ARE BEING CONSIDERED

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
THE CLEAN AIR ACT AND AMENDMENTS (Continued)			<ul style="list-style-type: none"> ● USE THE BEST AVAILABLE CONTROL TECHNOLOGY (BACT) IN ORDER TO LIMIT THE AIR EMISSIONS FROM VARIOUS PROCESSES. 	<ul style="list-style-type: none"> ● BEST AVAILABLE CONTROL TECHNOLOGY (BACT) WILL BE REQUIRED OF THERMAL EOR FACILITIES.
FEDERAL WATER POLLUTION CONTROL ACT (FWPCA) (P.L. 92-500, P.L. 95-576)	OCTOBER 1972/NOVEMBER 1978	EPA	<ul style="list-style-type: none"> ● SECTIONS 301 AND 306 OF FWPCA ESTABLISH A SYSTEM OF DISCHARGE AND AMBIENT STANDARDS FOR REGULATING POLLUTION FROM NON-MUNICIPAL (i.e., INDUSTRIAL) POINT SOURCE CATEGORIES. ● SECTION 303 DEFINES THAT STATES MUST ESTABLISH AND OBTAIN EPA APPROVAL OF WATER QUALITY STANDARDS. ● EPA OR AUTHORIZED STATES HAVE THE RESPONSIBILITY TO ISSUE DISCHARGE PERMITS UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES). AMBIENT STANDARDS PREVAIL WHERE THEIR ATTAINMENT WOULD REQUIRE DISCHARGE LIMITATIONS MORE STRINGENT THAN THOSE OF NSPS. 	<ul style="list-style-type: none"> ● EFFLUENT GUIDELINES HAVE NOT BEEN DEVELOPED FOR MOST FOSSIL ENERGY TECHNOLOGIES. THE PERMIT REQUIREMENTS ARE DETERMINED ON A CASE-BY-CASE BASIS TO MEET STATE PLANS. ● NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES) PERMITS ARE REQUIRED TO CONTROL WASTEWATER DISCHARGE INTO NAVIGABLE AND UNDERGROUND WATER SYSTEMS.

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
FEDERAL WATER POLLUTION CONTROL ACT (Continued)			<ul style="list-style-type: none"> ● A "NO DISCHARGE" GOAL FOR ELIMINATING THE DISCHARGE OF POLLUTANTS INTO THE NATION'S WATERS BY 1985 HAS BEEN SET. IN THE INTERIM, THE GOAL IS TO MAKE ALL WATERS SUCH AS TO PROVIDE FOR THE PREPARATION OF FISH AND WILDLIFE AND ADEQUATE FOR RECREATION. 	
SAFE DRINKING WATER ACT (SDWA) (P.L. 93-523, P.L. 95-190)	DECEMBER 1974/NOVEMBER 1977	EPA	<ul style="list-style-type: none"> ● THE PURPOSE OF SDWA IS TO PROTECT THE PUBLIC WATER SUPPLY SYSTEMS FROM BEING CONTAMINATED FROM SURFACE AND SUBSURFACE ACTIVITIES OF MAN. ● THE NATIONAL INTERIM DRINKING WATER REGULATIONS JUDGE THE ALLOWABLE CONTAMINANT LEVELS FOR POSSIBLE PHYSICAL, CHEMICAL, MICROBIOLOGICAL, AND RADIOLOGICAL POLLUTANTS IN PUBLIC WATER SYSTEMS. EXHIBIT 3-2 SHOWS THE TYPICAL CONSTITUENTS IN WASTEWATERS FROM THERMAL EOR PROCESSES, WHOSE CONCENTRATIONS ARE LIMITED BY THE NATIONAL INTERIM PRIMARY DRINKING WATER STANDARDS. 	<ul style="list-style-type: none"> ● WASTEWATER DISCHARGES MAY REQUIRE ADDITIONAL TREATMENT FOR REMOVAL OF HEAVY METALS OR ORGANIC WASTES PRIOR TO THEIR REINJECTION TO THE ONSITE DISPOSAL WELLS.

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FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
SAFE DRINKING WATER ACT (Continued)			<ul style="list-style-type: none"> THE UNDERGROUND INJECTION CONTROL PROGRAM REGULATIONS OF SDWA REQUIRE THE STATES TO ESTABLISH MINIMUM REQUIREMENTS FOR EFFECTIVE PROGRAMS TO PREVENT UNDERGROUND INJECTION ACTIVITIES WHICH ENDANGER DRINKING WATER RESOURCES. 	<ul style="list-style-type: none"> THE UNDERGROUND INJECTION ACTIVITIES IN THERMAL EOR PROCESSES ARE SUBJECT TO BE REGULATED BY SDWA.
139 TOXIC SUBSTANCE CONTROL ACT (TSCA) (P.L. 94-469)	OCTOBER 1976	EPA	<ul style="list-style-type: none"> THE PURPOSE OF THIS ACT IS TO REGULATE THE RELEASES OF CHEMICALS IDENTIFIED AS BEING TOXIC TO LIVING ORGANISMS IN CLOSE COORDINATION WITH THE WATER POLLUTION CONTROL ACT. 	<ul style="list-style-type: none"> DISPOSAL OF CERTAIN SPECIFIC MATERIALS PRODUCED IN THERMAL EOR PROCESSES ARE REGULATED UNDER THIS ACT.
NOTICE TO LESSEES AND OPERATORS OF FEDERAL AND INDIAN OIL AND GAS LEASES (USGSNTL-2B)	OCTOBER 1977	DOI	<ul style="list-style-type: none"> THESE REGULATIONS GOVERN THE HANDLING, STORAGE, AND DISPOSAL OF WASTEWATERS PRODUCED FROM OIL AND GAS WELLS ON FEDERAL AND INDIAN LEASE LANDS 	<ul style="list-style-type: none"> THE WASTEWATERS PRODUCED CAN BE DISPOSED OF ONLY BY SUBSURFACE INJECTION, IMPOUNDMENT IN LINED PITS, OR BY OTHER ENVIRONMENTALLY ACCEPTABLE MEANS.

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
GUIDELINES FOR IMPLEMENTATION OF SPILL PREVENTION CONTROL (40CFR112.7; 38 FR34164)	DECEMBER 11, 1973*/1976	EPA	<ul style="list-style-type: none"> IN ORDER TO PREVENT THE DISCHARGE OF OIL AND OIL PRODUCTS INTO OR UPON THE NAVIGABLE WATERS OF THE U.S. AND ADJOINING SHORELINES, EPA HAS ESTABLISHED REGULATIONS TO DEVELOP SPILL PREVENTION CONTROL AND COUNTERMEASURE PLANS INVOLVING THE CONSTRUCTION OF DIKES, BERMS, CULVERTS, WEIRS, AND OTHER ENGINEERING STRUCTURES NECESSARY TO CONTAIN A POSTULATED ACCIDENTAL SPILL OF OIL OR OIL-REGULATED SUBSTANCES. 	<ul style="list-style-type: none"> HANDLING AND ONSITE STORAGE OF RECOVERED HEAVY OILS MAY LEAD TO ACCIDENTAL SPILLS THUS AFFECTING THE QUALITY OF LOCAL NAVIGABLE WATERS. SURFACE WATER MONITORING DURING RAINSTORMS AS WELL AS DURING AND IMMEDIATELY FOLLOWING ANY DISCHARGE OF RETAINED WATERS INTO SURFACE-WATER BODIES IS REQUIRED.
THERMAL DISCHARGE (40 CFR122; 39FR 36176)	OCTOBER 8. 1974*	EPA	<ul style="list-style-type: none"> THE REGULATIONS FOR THERMAL EFFLUENT DISCHARGE LIMITATIONS HAVE BEEN FORMULATED FOR THE POINT SOURCES TO ENSURE THE PROTECTION AND PROPAGATION OF A BALANCED, INDIGENOUS COMMUNITY OF SHELLFISH, FISH, AND WILDLIFE IN AND ON THE BODY OF WATER INTO WHICH THE DISCHARGE IS MADE. 	<ul style="list-style-type: none"> THERMAL DISCHARGES AS A RESULT OF ONSITE STEAM GENERATION ARE SUBJECTED TO THESE LIMITATIONS.

*DATE PUBLISHED IN FEDERAL REGISTER.

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
MARINE PROTECTION RESEARCH AND SANCTUARIES ACT (P.L. 92-535, P.L. 95-153)	OCTOBER 1972/NOVEMBER 1977	EPA	<ul style="list-style-type: none"> REGULATE, PREVENT, AND LIMIT THE DUMPING OF ALL TYPES OF MATERIALS INTO OCEAN WATERS WHICH WOULD ADVERSELY AFFECT HUMAN HEALTH, WELFARE, OR AMENITIES OR THE MARINE ENVIRONMENT, ECOLOGICAL SYSTEMS, OR ECONOMIC POTENTIALITIES. 	<ul style="list-style-type: none"> PERMITS ARE REQUIRED FOR ACTIVITIES IN WETLAND AREAS WHICH MAY RESTRICT POTENTIAL SITES FOR THERMAL EOR PROJECTS.
WILD AND SCENIC RIVERS ACT (P.L. 90-542, P.L. 94-486)	OCTOBER 1968/OCTOBER 1976	DOI, DOA	<ul style="list-style-type: none"> IN ORDER TO SUSTAIN THE SCENIC, RECREATIONAL, GEOLOGIC, FISH AND WILD-LIFE, HISTORIC, CULTURAL AND OTHER SIMILAR VALUES OF CERTAIN SELECTED RIVERS, PRECAUTIONARY MEASURES TO PRESERVE THE FREE-FLOWING CONDITIONS OF WATER BODIES ARE TO BE TAKEN. 	<ul style="list-style-type: none"> THERMAL EOR PROJECTS MUST NOT DEGRADE THE QUALITY OF LOCAL WILDLIFE AND SCENIC RIVERS.
OIL SPILL REGU- LATIONS (33CFR153, 41FR12628)	MARCH 25, 1976*	U.S. COAST GUARD, DOT	<ul style="list-style-type: none"> THE PURPOSES OF THESE REGULATIONS ARE TO DEFINE THE NOTIFICATION PROCEDURES IN CASE OF ACCIDENTAL OIL SPILLS, THE SUGGESTED MEANS FOR THEIR REMOVAL, AND THE COSTS THAT MAY BE IMPOSED FOR THE REMOVAL OF OILS 	<ul style="list-style-type: none"> ACCIDENTAL SPILLS OF RECOVERED HEAVY OIL DURING THE HANDLING OR STORAGE PHASES HAVE THE POTENTIAL OF AFFECTING THE COASTAL WATER QUALITY.

*DATE PUBLISHED IN FEDERAL REGISTER

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
POLICIES AND PROCEDURES FOR THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (40CFR125; 38FR13527)	MAY 22, 1972/SEPTEMBER 1978	EPA	<ul style="list-style-type: none"> THE REGULATIONS PRE- SCRIBE THE POLICY AND PROCEDURES TO BE FOLLOWED PERTAINING TO DISCHARGES FROM ALL POINT SOURCES INTO NAVIGABLE WATERS, THE WATERS OF THE CONTIGUOUS ZONE OR THE OCEAN. 	<ul style="list-style-type: none"> THERE IS A MANDATORY REQUIREMENT FOR THE MONITORING OF VARIOUS TOXIC POLLUTANT EFFLUENTS IN THE WASTEWATERS FROM THERMAL EOR SITES PRIOR TO THEIR DISPOSAL.
WATER RESOURCE PLANNING ACT (P.L. 89-80, P.L. 95-404) 142	JULY 1965/JUNE 1971	WRC*	<ul style="list-style-type: none"> IN ORDER TO MEET THE EXPANDING WATER DEMANDS IN THE COUNTRY, THE WATER RESOURCES COUNCIL WAS CREATED. AMONG OTHER DUTIES, THE COUNCIL IS RESPONSIBLE FOR PLANNING WATER AND RELATED LAND RESOURCES. 	<ul style="list-style-type: none"> THE POTENTIAL THERMAL EOR PROJECTS LOCATED IN THE WATER SHORTAGE AREAS WILL BE AFFECTED DUE TO WATER AVAILABLE CONSTRAINTS.

*Water Resources Council (WRC) consists of DOI, DOA, DA, HEW, AND FPC.

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
NATIONAL ENVIRONMENTAL POLICY ACT (NEPA) (P.L. 94-52; P.L. 94-83)	1969/AUGUST 1975	EPA	<ul style="list-style-type: none"> THE PURPOSES OF THIS ACT ARE TO DECLARE A NATIONAL POLICY TO ENCOURAGE PRO- DUCTIVE AND ENJOYABLE HARMONY BETWEEN MAN AND HIS ENVIRONMENT, TO PRO- MOTE EFFORTS WHICH WILL PREVENT OR ELIMINATE DAMAGE TO THE ENVIRONMENT AND BIOSPHERE AND STIMU- LATE THE HEALTH AND WEL- FARE OF MAN AND TO ENRICH THE UNDERSTANDING OF THE ECOLOGICAL SYSTEMS AND NATURAL RESOURCES IMPORTANT TO THE NATION. 	<ul style="list-style-type: none"> ENVIRONMENTAL IMPACT STATEMENTS (EIS) MUST BE PREPARED FOR ALL MAJOR FEDERAL PROJECTS SIGNIFICANTLY AFFECTING THE QUALITY OF HUMAN ENVIRONMENT.
NON-NUCLEAR ENERGY RESEARCH AND DEVELOPMENT ACT (P.L. 93- 577)	1974	DOE	<ul style="list-style-type: none"> DOE IS REQUIRED TO PRE- PARE ENVIRONMENTAL, ECO- NOMIC, AND SOCIAL ASSESS- MENTS ON THE AVAILABILITY OF ADEQUATE WATER RESOURCES FOR ANY PRO- POSED PROJECT WHICH MAY HAVE A SIGNIFICANT IMPACT. 	<ul style="list-style-type: none"> WATER AVAILABILITY ASSESS- MENTS ARE REQUIRED FOR THERMAL EOR PROJECTS WHICH MAY HAVE A SIGNIFI- CANT IMPACT. THE RESPONSIBILITIES ARE SHARED WITH THE WATER RESOURCES COUNCIL (WRC). ENVIRONMENTAL CONSEQUENCES OF PROPOSED THERMAL EOR PROJECTS MUST BE ANALYZED IN EVALUATING THEIR POTENTIAL.

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FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
RESOURCES CONSER- VATION AND RECOVERY ACT (P.L. 91-512, P.L. 93-14)	OCTOBER 1970/OCTOBER 1976	EPA	<ul style="list-style-type: none"> THE MAIN PURPOSE OF THIS ACT IS TO PROVIDE TECHNICAL AND FINANCIAL ASSISTANCE FOR THE DEVELOPMENT OF MANAGEMENT PLANS FOR THE RECOVERY OF ENERGY FROM DISCARDED MATERIALS AND TO REGULATE THE MANAGEMENT PROCEDURES FOR HAZARDOUS WASTES. 	<ul style="list-style-type: none"> SOLID WASTE AND HAZARDOUS WASTE DISPOSAL MEASURES MUST COMPLY WITH THE MOST STRINGENT AIR AND WATER QUALITY STANDARDS.
NOISE CONTROL ACT (P.L. 92- 574, P.L. 94- 301) 144	OCTOBER 1972/MAY 1976	EPA	<ul style="list-style-type: none"> THE NOISE EMISSION STANDARDS FOR MAJOR NOISE SOURCES SUCH AS CONSTRUCTION AND TRANSPORTATION EQUIPMENT HAVE BEEN ESTABLISHED. RESPONSIBILITY FOR REGULATING THE NOISE LEVELS DURING OPERATION LIES WITH THE STATE AND LOCAL GOVERNMENTS. IN ORDER TO PROTECT THE PUBLIC HEALTH AND WELFARE, LONG-TERM AMBIENT NOISE CRITERIA HAS BEEN DEFINED. 	<ul style="list-style-type: none"> THE ESTABLISHED MANDATORY CRITERIA OF AMBIENT NOISE QUALITY IS REQUIRED TO BE OBSERVED AT THE PROPERTY LINE OF THE THERMAL EOR SITES.

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
OCCUPATIONAL SAFETY AND HEALTH ACT (P.L. 91-596)	1970	DOL	<ul style="list-style-type: none"> HEALTH AND SAFETY REGULATIONS MUST BE ENFORCED FOR WORKERS AT ALL FEDERAL FACILITIES. 	<ul style="list-style-type: none"> HEALTH AND SAFETY REGULATIONS MUST BE MET FOR WORKERS AT THERMAL EOR TEST SITES.
NATIONAL HISTORIC PRESERVATION ACT (80USC 915, 16USC 470)	1966	DOI	<ul style="list-style-type: none"> THE FEDERAL PROJECTS CANNOT DISTURB IMPORTANT HISTORIC OR CULTURAL SITES UNLESS NO ALTERNATIVE EXISTS. 	<ul style="list-style-type: none"> POTENTIAL FEDERAL THERMAL EOR PROJECT SITES CANNOT BE LOCATED ON HISTORICAL SITES.
ENDANGERED SPECIES ACT (P.L. 94-359)	DECEMBER 1973/NOVEMBER 1978	DOI	<ul style="list-style-type: none"> THE ENDANGERED SPECIES ACT IS APPLICABLE TO ALL FEDERAL AGENCIES PRIOR TO INITIATIONS OF NEW PROJECTS. THE PURPOSES OF THIS ACT ARE TO PROVIDE MEANS WHEREBY THE ECOSYSTEMS UPON WHICH ENDANGERED AND THREATENED SPECIES DEPEND MAY BE CONSERVED AND TO PROVIDE A PROGRAM FOR CONSERVATION OF THESE SPECIES. 	<ul style="list-style-type: none"> DOCUMENTATION OF ENDANGERED (AQUATIC AND TERRESTRIAL) SPECIES AT OR NEAR POTENTIAL FEDERAL THERMAL EOR TEST SITES IS REQUIRED.
NATIONAL INTERIM PRIMARY DRINKING WATER STANDARDS (40CFR 142, 41FR 2916)	JANUARY 1976/FEBRUARY 1978	EPA	<ul style="list-style-type: none"> THE PRIMARY DRINKING WATER STANDARDS APPLICABLE TO PUBLIC WATER SYSTEMS ARE IMPLEMENTED THROUGH STATE AND LOCAL AUTHORITIES. 	<ul style="list-style-type: none"> THE THERMAL EOR PROJECTS HAVE THE POTENTIAL OF IMPACTING THE GROUND-WATER RESOURCES THEREBY AFFECTING THE PUBLIC WATER SUPPLIES.

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
(Continued)

CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
PROPOSED REGU- LATIONS ON DESIGNATION OF HAZARDOUS SUB- STANCES (40FR 59960)	DECEMBER 1975*	EPA	<ul style="list-style-type: none"> THE REGULATIONS SET THE STAGE FOR THE DISPOSAL OF HAZARDOUS WASTES IN AN ENVIRONMENTALLY ACCEPTABLE MANNER. 	<ul style="list-style-type: none"> CERTAIN LIQUID AND SOLID WASTES FROM THERMAL EOR FIELDS ARE CLASSIFIED AS HAZARDOUS WASTES AND, THEREFORE, ARE TO BE DISPOSED OF ACCORDING TO THE REGULATIONS.
NATIONAL OIL AND HAZARDOUS SUB- STANCES POLLUTION CONTINGENCY PLAN (40CFR 1510, 40 FR 6282)	FEBRUARY 1975/MARCH 1976	CEQ	<ul style="list-style-type: none"> THE PURPOSE OF THE PLAN IS TO DEVELOP MEANS TO MINIMIZE POTENTIAL DAMAGES FROM THE DIS-CHARGE OF OIL AND HAZARDOUS SUBSTANCES INTO THE AMBIENT ENVIRONMENT. 	<ul style="list-style-type: none"> THERMAL EOR PROJECTS ARE SUBJECTED TO THE CONTINGENCY PLAN MINI-MIZING ENVIRONMENTAL DEGRADATION.
146 SOLID WASTE DISPOSAL (PRO- POSED GUIDELINES FOR THERMAL PROCESSING AND LAND DISPOSAL OF SOLID WASTES)	APRIL 27, 1973*	EPA	<ul style="list-style-type: none"> THE GUIDELINES SUGGEST THE METHODOLOGY FOR THE DISPOSAL OF SOLID WASTES BY INCINERATION AND LANDFILL MEANS. 	<ul style="list-style-type: none"> THE GUIDELINES APPLY TO THE SOLID WASTES PRODUCED FROM THERMAL EOR FIELDS.
IMPLEMENTATION OF PROCEDURAL PROVISIONS: FINAL REGULA- TIONS (43FR 55978)	NOVEMBER 29, 1978*	CEQ	<ul style="list-style-type: none"> THE FINAL REGULATIONS ESTABLISH UNIFORM PRO-CE- DURES FOR IMPLEMENTING THE PROCEDURAL PRO- VISIONS OF NEPA. THE PURPOSE OF THESE REGU- LATIONS IS TO BE AN EFFECTIVE AND EFFICIENT TOOL FOR THE PREPARATION OF ENVIRONMENTAL IMPACT STATEMENTS. 	<ul style="list-style-type: none"> ALL FEDERAL THERMAL EOR PROJECTS ARE SUBJECTED TO NEPA REGULATIONS.
*DATE PUBLISHED IN FEDERAL REGISTER.		13		

FEDERAL REGULATORY REQUIREMENTS FOR THERMAL EOR PROCESSES
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CITATION IDENTIFICATION	DATES IDENTIFICATION DATE ENACTED/LAST AMENDED	RESPONSIBLE AGENCY	PURPOSE/KEY POINTS OF THE LEGISLATION	APPLICABILITY TO THERMAL EOR PROCESSES
GUIDELINES FOR PREPARATION OF ENVIRONMENTAL IMPACT STATE- MENTS (38FR 20550)	AUGUST 1, 1973*	CEQ	<ul style="list-style-type: none"> THE CEQ GUIDELINES ARE MEANT TO STEER FEDERAL AGENCIES FOR PREPARING DETAILED ENVIRONMENTAL STATEMENTS ON PROPOSALS FOR LEGISLATION AND OTHER MAJOR FEDERAL ACTIONS SIGNIFICANTLY AFFECTING THE QUALITY OF THE HUMAN ENVIRONMENT AS REQUIRED BY SECTION 102(2) (C) OF NEPA. 	<ul style="list-style-type: none"> THE GUIDELINES ARE ORIENTED TOWARD LAYING DOWN THE METHODOLOGY FOR THE PREPARATION OF ENVIRONMENTAL DOCUMENTS AS REQUIRED UNDER NEPA FOR THERMAL EOR PROJECTS.
147 GUIDELINES FOR ENVIRONMENTAL REVIEW (40CFR 711, 42FR 4827)	JANUARY 26, 1977	DOE	<ul style="list-style-type: none"> THE ERDA (NOW DOE) GUIDELINES PROVIDE THE DIRECTIVE ROLE FOR MEETING NEPA REQUIREMENTS AS ORIENTED TOWARD FULFILLING THE GOALS OF THIS AGENCY. 	<ul style="list-style-type: none"> THE ENVIRONMENTAL ISSUES PERTAINING TO DOE-SPONSORED THERMAL EOR PROJECTS ARE SUBJECTED TO THESE GUIDELINES.

*DATE PUBLISHED IN FEDERAL REGISTER.

ADDENDUM B:

STATE ENVIRONMENTAL REGULATORY REQUIREMENTS
APPLICABLE TO THERMAL EOR PROCESSES

1. CALIFORNIA

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
CALIFORNIA AIR POLLUTION CONTROL LAW	AMENDED JANUARY 1, 1978	<ul style="list-style-type: none"> THE LOCAL (COUNTY) AND REGIONAL (AIR POLLUTION CONTROL DISTRICTS, AIR BASINS) HAVE THE PRIMARY RESPONSIBILITY TO CONTROL THE AIR EMISSIONS FROM THERMAL EOR SITES. THE AIR EMISSIONS LIMITATIONS FROM STEAM GENERATORS VARY WIDELY FROM DISTRICT TO DISTRICT. SAMPLE EMISSION LIMITATIONS FOR KERN COUNTY AIR POLLUTION CONTROL DISTRICT ARE AS LISTED IN APPENDIX D.
CALIFORNIA AIR POLLUTION CONTROL REGULATIONS	LAST AMENDED (IN PART) SEPTEMBER 30, 1978	<ul style="list-style-type: none"> THE ALLOWABLE EMISSION LEVELS FROM THERMAL EOR FIELDS ARE SUBJECT TO PERMIT REQUIREMENTS SET FORTH BY THE DISTRICT BOARD THE AMBIENT AIR QUALITY MONITORED AT THE PROPERTY LINE OF THE FACILITY IS INDICATIVE OF NEEDED AIR DILUTIONS REQUIRED FOR VARIOUS CRITERIA POLLUTANTS
CLEAN WATER AND WATER CONSERVATION BOARD	LAW OF 1978	<ul style="list-style-type: none"> THE QUANTITIES OF WATER AVAILABLE FOR THERMAL EOR PROCESSES ARE TO BE DETERMINED BY THE STATE WATER RESOURCES CONTROL BOARD THROUGH PERMIT REQUIREMENTS.
WATER RECLAMATION LAW	-	<ul style="list-style-type: none"> THE WATER CONSERVATION AND UTILIZATION REQUIREMENTS FOR RECLAIMED WATER IN THERMAL EOR OPERATIONS MAY BE MANDATORY.
CALIFORNIA WATER POLLUTION CONTROL LAWS	LAST AMENDED 1977	<ul style="list-style-type: none"> THE STATE SURFACE WATER QUALITY IS TO BE PROTECTED FROM BEING AFFECTED BY DISCHARGES FROM THERMAL EOR FIELDS AS DEFINED UNDER PORTER-COLOGNE WATER QUALITY CONTROL ACT. THE GROUNDWATER QUALITY OF THE STATE IS NOT TO BE AFFECTED BY ANY UNDESIRABLE UNDERGROUND ACTIVITY DUE TO THERMAL EOR OPERATIONS.

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1. CALIFORNIA
(Continued)

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
HAZARDOUS WASTE REGULATIONS	NOVEMBER 1977	<ul style="list-style-type: none"> THE HAZARDOUS WASTES FROM THERMAL EOR FIELDS ARE TO BE HANDLED, STORED, AND DISPOSED OF ACCORDING TO THESE REGULATIONS.
CALIFORNIA LAWS FOR CONSERVATION OF PETROLEUM AND GAS	-	<ul style="list-style-type: none"> THE PROCEDURES FOR DRILLING, CASING, AND ABANDONMENT OF WELLS AND OTHER PRECAUTIONARY MEASURES ARE TO BE OBSERVED AS DESCRIBED UNDER THESE LAWS.
WASTE DISCHARGE REQUIREMENTS: NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM	March 1977	<ul style="list-style-type: none"> NO NPDES PERMITS ARE REQUIRED FOR UNDERGROUND DISCHARGES OF WASTEWATERS BY REINJECTION INTO THE SAME WELL FORMATIONS. THE PROCEDURES FOR THE DISPOSAL OF BRINES, ROTARY DRILLING MUDS CONTAINING TOXIC MATERIALS, ETC. ARE TO BE OBSERVED AS DESCRIBED UNDER GROUP I, INDUSTRIAL ORIGIN WASTES. THE MONITORING OF EFFLUENT WASTEWATERS AND SUBSURFACE DISPOSAL WATERS IS REQUIRED FOR EACH DISCHARGE OF POLLUTANTS INTO WELLS. TO PROTECT THE BENEFICIAL USES OF SUBSURFACE WATERS, THE IMPROPER DISCHARGES OF WASTES INTO SUBSURFACE WATERS ARE PROHIBITED.
OIL SPILL CONTINGENCY PLAN	REVISED MARCH 1974	<ul style="list-style-type: none"> THIS PLAN IS AN EXTENSION OF THE CALIFORNIA EMERGENCY PLAN, PART II, AND IS DESIGNED TO PROTECT THE LIVES AND HEALTH OF THE POPULACE, PUBLIC AND PRIVATE PROPERTY, AND THE LIVING AND NATURAL RESOURCES DUE TO SPILLAGES OF OIL FROM THERMAL EOR FIELDS.

2. TEXAS

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
TEXAS CLEAN AIR ACT	ARTICLE 4477-5, BILL 739 OF 1972	<ul style="list-style-type: none"> ● UNDER THIS ACT, THE OPERATIONS OF THERMAL EOR CANDIDATE RESERVOIRS ARE NOT TO INTERFERE WITH THE HEALTH, GENERAL WELFARE AND OTHER SOCIAL (PHYSICAL PROPERTY, VISIBILITY, AND AESTHETIC) VALUES.
TEXAS AIR CONTROL REGULATIONS	ADOPTED JANUARY 26, 1972; LAS AMENDED MARCH 28, 1975	<ul style="list-style-type: none"> ● THE SOURCE SAMPLING AND MONITORING REQUIREMENTS FOR AIR EMISSIONS FROM THERMAL EOR SITES ARE AT THE DISCRETION OF THE STATE. ● THE NATIONAL PRIMARY AND SECONDARY AMBIENT AIR QUALITY STANDARDS ARE APPLICABLE FOR MONITORING THE AMBIENT AIR QUALITY AT THE PROPERTY LINE OF THE HEAVY OIL FIELDS (SEE APPENDIX E).
151 TEXAS REGULATION I: CONTROL OF AIR POLLUTION FROM SMOKE, VISIBLE EMISSIONS, AND PARTICULATE MATTER	ADOPTED JANUARY 26, 1972; LAST AMENDED DECEMBER 5, 1975	<ul style="list-style-type: none"> ● THE ALLOWABLE GROUND LEVEL CONCENTRATIONS OF PARTICULATE MATTER DUE TO THE OPERATIONS OF THERMAL EOR SITES ARE NOT TO EXCEED THE FOLLOWING LIMITS: 100 mg/m³ AVERAGED OVER 5 CONSECUTIVE HOURS, 200 mg/m³ AVERAGED OVER 3 CONSECUTIVE HOURS, AND 400 mg/m³ AVERAGED OVER A 1-HOUR PERIOD. ● THE ALLOWABLE EMISSIONS OF PARTICULATE MATTER FROM COAL-FIRED STEAM GENERATORS ARE NOT TO EXCEED 0.3 lbs. PER MILLION Btu HEAT INPUT, MAXIMUM 2-HOURS AVERAGE.
TEXAS REGULATION II: CONTROL OF AIR POLLUTION FROM SULFUR COMPOUNDS	ADOPTED JANUARY 26, 1972; LAST AMENDED JANUARY 30, 1975.	<ul style="list-style-type: none"> ● THE ALLOWABLE EMISSIONS OF SULFUR DIOXIDE FROM LIQUID-FIRED STEAM GENERATORS ARE NOT TO EXCEED 400 ppm BY VOLUME AND 3.0 lbs. PER MILLION Btu HEAT INPUT FROM COAL-FIRED GENERATORS.

2. TEXAS
(Continued)

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
TEXAS REGULATION II: CONTROL OF AIR POLLUTION FROM SULFUR COMPOUNDS	ADOPTED JANUARY 26, 1972; LAST AMENDED JANUARY 30, 1975	<ul style="list-style-type: none"> THE ALLOWABLE GROUND LEVEL CONCENTRATION OF HYDROGEN SULFIDE IS NOT TO EXCEED 0.08 ppm AVERAGED OVER ANY 30-MINUTE PERIOD IF THE DOWNWIND CONCENTRATION OF HYDROGEN SULFIDE AFFECTS A PROPERTY USED FOR RESIDENTIAL, BUSINESS, OR COMMERCIAL PURPOSES AND 0.12 ppm (30-MINUTE AVERAGE) IF THE DOWNWIND CONCENTRATION AFFECTS A PROPERTY USED FOR INDUSTRIAL PROPERTY AND VACANT LAND TRACTS.
TEXAS PERMIT SYSTEMS PROCEDURES	ADOPTED JULY 5, 1972; LAST AMENDED OCTOBER 22, 1976	<ul style="list-style-type: none"> THE OPERATION OF STEAM GENERATORS FOR THERMAL EOR PROJECTS IS SUBJECTED TO AIR EMISSION PERMIT REQUIREMENTS OF TEXAS AIR CONTROL BOARD AS EXPLAINED UNDER THESE PROCEDURES.
TEXAS WATER QUALITY ACT 152	EFFECTIVE SEPTEMBER 1, 1977	<ul style="list-style-type: none"> THE PERMITS FOR THE SUBSURFACE DISPOSAL OF LIQUID WASTES RESULTING FROM THERMAL EOR ACTIVITIES ARE SUBJECTED TO THE REQUIREMENTS OF THE TEXAS RAILROAD COMMISSION. THE REGULATIONS REQUIRE CERTAIN SPECIFIC MEASURES TO BE TAKEN FOR THE PROTECTION AND PRESERVATION OF THE UNDERGROUND WATER QUALITY FROM THE DISPOSAL AND OBSERVATION WELLS OPERATIONS.
TEXAS WATER QUALITY RULES	ADOPTED MARCH 26, 1970; LAST AMENDED MAY 5, 1977	<ul style="list-style-type: none"> IN CASE OF ACCIDENTAL SPILLS OF ONSITE STORED HEAVY OILS AT THERMAL EOR SITES, THE REGULATORY REQUIREMENTS ARE SUBJECTED TO THESE REGULATIONS. THE THERMAL EOR RESERVOIRS ARE SUBJECTED TO THE 1972 AMENDMENTS TO THE FEDERAL WATER POLLUTION CONTROL ACT WHICH REQUIRE THE STATES TO CERTIFY WHETHER OR NOT THE EFFLUENT DISCHARGES INTO DISPOSAL WELLS ARE IN COMPLIANCE WITH THE ACT.

2. TEXAS
(Continued)

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
TEXAS WATER QUALITY STANDARDS	APPROVED OCTOBER 25, 1973; LAST AMENDED JANUARY 1975	<ul style="list-style-type: none"> THE SURFACE WATERS ARE CLASSIFIED INTO FOUR CATEGORIES: RIVER BASIN WATERS, COASTAL BASIN WATERS, BAY WATERS AND GULF WATERS. THE OPERATION OF THERMAL EOR FACILITIES IS NOT TO AFFECT THE PRE-ESTABLISHED SURFACE WATER QUALITY STANDARDS AND CRITERION FOR CERTAIN PHYSICAL AND CHEMICAL PARAMETERS.
TEXAS SOLID WASTE DISPOSAL ACT	ACTS OF 1969; LAST AMENDED (IN PART) 1977	<ul style="list-style-type: none"> THE SOLID WASTES GENERATED FROM THE THERMAL EOR SITES ARE TO BE DISPOSED OF IN A MANNER NOT TO IMPACT THE PUBLIC HEALTH AND WELFARE ENVIRONMENT DURING COLLECTION, HANDLING, STORAGE, AND DISPOSAL PHASES.
TEXAS REGULATION ON INDUSTRIAL SOLID WASTE MANAGEMENT	EFFECTIVE DECEMBER 31, 1975; LAST AMENDED MARCH 3, 1977	<ul style="list-style-type: none"> THESE REGULATIONS DESCRIBE THE PROCEDURAL RESPONSIBILITIES PERTAINING TO HANDLING OF SOLID WASTES FROM THERMAL EOR SITES IN ENVIRONMENTALLY ACCEPTABLE MANNERS.

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3. WYOMING

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
WYOMING AIR QUALITY STANDARDS AND REGULATIONS	ADOPTED JANUARY 22, 1972; LAST AMENDED SEPTEMBER 15, 1976	<ul style="list-style-type: none"> ● THESE REGULATIONS REQUIRE THE OPERATION OF THE THERMAL EOR PROJECTS NOT TO IMPACT THE EXISTING LOCAL AMBIENT AIR QUALITY STANDARDS (SEE APPENDIX E) BEYOND THE PROPERTY LINE. ● THE ALLOWABLE EMISSIONS OF PARTICULATE MATTER FROM COAL-FIRED STEAM GENERATORS ARE NOT TO EXCEED 0.1 ppm Btu HEAT INPUT (MAXIMUM 2-HOUR AVERAGE). ● THE VISIBILITY OF THE AIR EMISSIONS IS NOT TO BE GREATER THAN 20 PERCENT CAPACITY. ● THERE ARE NO EMISSION LIMITS FOR SULFUR DIOXIDE EMISSIONS FROM STEAM GENERATORS UNDER 250 MMBtu PER HOUR HEAT INPUT. ● THE EMISSIONS OF FUGITIVE DUST FROM THE THERMAL EOR OPERATIONS ARE TO BE CONTROLLED ACCORDING TO THE REGULATIONS OUTLINED IN SECTION 14. ● THE ODOR EMISSIONS FROM THERMAL EOR OPERATIONS DETECTABLE BEYOND THE PROPERTY LINE, AFTER A SPECIFIED DILUTION, ARE NOT PERMITTED. ● THE EMISSIONS FROM THE THERMAL EOR TEST FACILITY ARE NOT TO CAUSE SIGNIFICANT DETERIORATION OF EXISTING AMBIENT AIR QUALITY AND, THEREFORE, THE UTILIZATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT) IS REQUIRED.

3. WYOMING
(Continued)

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
WYOMING ENVIRONMENTAL QUALITY ACT	EFFECTIVE JULY 1, 1973; LAST AMENDED MARCH 9, 1978	<ul style="list-style-type: none"> THE PROCEDURES FOR THE OPERATION OF DISPOSAL AND OBSERVATION WELLS ARE TO ADHERE TO CAPPING, SEALING, OR PLUGGING REQUIREMENTS AS DESCRIBED IN SECTION 35-11-404.
WYOMING NPDES PERMIT PROGRAM REGULATIONS	ADOPTED JULY 30, 1974	<ul style="list-style-type: none"> UNDER FEDERAL WATER POLLUTION CONTROL ACT AMENDMENTS OF 1972, THE WASTE DISCHARGES FROM THERMAL EOR SITES ARE SUBJECTED TO NPDES PERMIT REQUIREMENTS.
WYOMING WATER QUALITY STANDARDS	ADOPTED JULY 30, 1974; EFFECTIVE AUGUST 28, 1975	<ul style="list-style-type: none"> THE EFFLUENTS FROM THERMAL EOR TEST SITES ARE NOT TO IMPACT THE PRE-ESTABLISHED PHYSICAL AND CHEMICAL SURFACE WATER QUALITY STANDARDS.
WYOMING SPILLS REGULATIONS	ADOPTED JANUARY 7, 1975	<ul style="list-style-type: none"> PROCEDURES FOR CONTROLLING ACCIDENTAL SPILLS OF HEAVY OILS INTO STATE WATERS ARE SUBJECTED TO THESE REGULATIONS.
WASTES FROM OIL FIELDS	-	<ul style="list-style-type: none"> THE DISPOSAL PROCEDURES FOR SOLID WASTES FROM THERMAL EOR FIELDS ARE SUBJECTED TO REGULATIONS SET FORTH BY THE WYOMING OIL AND GAS COMMISSION, THE UNITED STATES GEOLOGICAL SURVEY, AND THE BUREAU OF LAND MANAGEMENT.

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4. LOUISIANA

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
LOUISIANA AIR POLLUTION CONTROL REGULATIONS	AMENDED FEBRUARY 20, 1978	<ul style="list-style-type: none"> ● THE EMISSIONS FROM THERMAL EOR SITES ARE REQUIRED NOT TO AFFECT THE EXISTING AMBIENT AIR CONCENTRATIONS OF MAJOR CRITERIA POLLUTANTS (SEE APPENDIX E) BEYOND THE SITE LIMITS. ● THE SMOKE EMISSIONS FROM THERMAL EOR PROCESSES ARE NOT TO BE DARKER THAN NO. 1 ON THE RINGLEMANN SMOKE CHART FOR ANY FOUR CONSECUTIVE MINUTES. ● MANDATORY MEASURES FOR CONTROLLING THE FUGITIVE DUST EMISSIONS FROM THERMAL EOR SITES ARE REQUIRED TO BE TAKEN. ● THE ALLOWABLE EMISSIONS OF PARTICULATES FROM STEAM GENERATORS ARE LIMITED TO 0.7 ppm Btu OF HEAT INPUT. ● THE SULFUR DIOXIDE CONCENTRATION IN THE EFFLUENT GASES IS NOT TO EXCEED 2000 ppm BY VOLUME AT STANDARD CONDITIONS.
LOUISIANA RULES RELATING TO OIL AND GAS	AMENDED JANUARY 27, 1953	<ul style="list-style-type: none"> ● THE PROCEDURES GOVERNING DISPOSAL METHODS FOR WASTE OILS, BRINES, AND ALL OTHER MATERIALS PERTAINING TO PRODUCTION OF HEAVY OILS FROM THERMAL EOR SITES ARE SUBJECTED TO THESE RULES.
LOUISIANA WATER QUALITY CRITERIA	ADOPTED AUGUST 14, 1973; AMENDED MAY 26, 1977	<ul style="list-style-type: none"> ● THE WASTE EFFLUENTS FROM THERMAL EOR TEST SITES ARE NOT TO IMPACT THE EXISTING SURFACE WATER QUALITY CLASSES (A, B, C, D) OF STATE WATERS FOR VARIOUS PHYSICAL AND CHEMICAL PARAMETERS.

5. OKLAHOMA

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
OKLAHOMA REGULATION 6: PARTICULATE MATTER EMISSIONS FROM FUEL BURNING EQUIPMENT	EFFECTIVE JULY 21, 1970	<ul style="list-style-type: none"> THE ALLOWABLE EMISSIONS OF PARTICULATE MATTER FROM STEAM GENERATORS OF HEAT INPUT RATES OF 10 AND 100 MILLION Btu PER HOUR ARE 0.7 AND 0.35 ppm Btu's. FOR THE STEAM GENERATORS WITHIN THIS RANGE, THE EMISSION LIMITS ARE TO BE INTERPOLATED.
OKLAHOMA REGULATIONS 7, 9, 19: SMOKE PARTICULATES, HAZARDOUS CONTAMINANTS	REGULATION 7, EFFECTIVE APRIL 15, 1971; AMENDED DECEMBER 6, 1975; REGULATION 9, EFFECTIVE OCTOBER 15, 1972, AMENDED DECEMBER 6, 1975; REGULATION 19, EFFECTIVE DECEMBER 31, 1974	<ul style="list-style-type: none"> THE OPACITY OF SMOKE PRODUCED AS A RESULT OF COMBUSTION OF FUEL OIL (IN THE STEAM GENERATORS AND <i>IN SITU</i> COMBUSTION) IS NOT TO BE DARKER THAN NUMBER ONE (1) ON THE RINGLEMANN CHART OR TWENTY (20) PERCENT EQUIVALENT OPACITY. THE REGULATIONS REQUIRE THE EMPLOYING OF EFFECTIVE MEANS FOR THE CONTROL OF FUGITIVE DUST EMISSIONS FROM THE THERMAL EOR TEST SITES. THE HAZARDOUS POLLUTANT EMISSIONS FROM THE TEST SITES ARE TO BE REGULATED ACCORDING TO THE NATIONAL HAZARDOUS POLLUTANT EMISSION STANDARDS.
OKLAHOMA REGULATION 16, SULFUR OXIDES	EFFECTIVE JULY 1, 1972; AMENDED DECEMBER 9, 1974	<ul style="list-style-type: none"> THE ALLOWABLE EMISSIONS OF SULFUR DIOXIDE FROM STEAM GENERATORS BURNING LIQUID FUELS ARE NOT TO EXCEED 0.1 ppm Btu INPUT (MAXIMUM 2-HOUR AVERAGE) AND 1.2 ppm Btu INPUT (MAXIMUM 2-HOUR AVERAGE) FROM COAL-BURNING EQUIPMENT.

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5. OKLAHOMA
(Continued)

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
OKLAHOMA LEGISLATION 18, NITROGEN OXIDES	EFFECTIVE JULY 1, 1972	<ul style="list-style-type: none"> THE ALLOWABLE EMISSIONS OF NITROGEN DIOXIDE FROM STEAM GENERATORS OF RATED HEAT INPUT OF 50 MILLION Btu PER HOUR OR MORE USING LIQUID FUELS ARE NOT TO EXCEED 0.30 ppm Btu (MAXIMUM 2-HOUR AVERAGE) AND 0.70 ppm Btu HEAT INPUT (MAXIMUM 2-HOUR AVERAGE) FOR COAL-BURNING EQUIPMENT.
OKLAHOMA WATER QUALITY STANDARDS	ADOPTED DECEMBER 13, 1977	<ul style="list-style-type: none"> THE ACCIDENTAL SPILLS OF ONSITE STORED HEAVY OILS ARE NOT TO AFFECT THE EXISTING SURFACE WATER QUALITY OF STATE WATERS.
OKLAHOMA SOLID WASTE MANAGEMENT REGULATIONS	ADOPTED JUNE 13, 1971; LAST AMENDED JUNE 2, 1974	<ul style="list-style-type: none"> THE SOLID WASTES GENERATED FROM THE THERMAL EOR SITES ARE TO BE DISPOSED OF ACCORDING TO STATE PERMIT REQUIREMENTS ENFORCED AT COUNTY AND CITY LEVELS.

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6. KANSAS

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
KANSAS AIR POLLUTION EMISSION CONTROL REGULATIONS	ADOPTED JANUARY 1, 1972; LAST AMENDED JANUARY 1, 1974	<ul style="list-style-type: none"> ● THE ALLOWABLE EMISSIONS OF PARTICULATE MATTER FROM STEAM GENERATORS OF HEAT INPUT UP TO 10 AND 50 MMBtu's PER HOUR ARE 0.6 and 0.41 POUND RESPECTIVELY. ● THE SMOKE OPACITY FROM THE EXISTING THERMAL EOR EQUIPMENT IS NOT TO BE DARKER THAN 40 PERCENT AND FROM THE NEW EQUIPMENT NOT DARKER THAN 20 PERCENT.
KANSAS WATER POLLUTION CONTROL LAWS	KSA 55-136, AMENDED MARCH 8, 1974	<ul style="list-style-type: none"> ● THE REGULATIONS PERTAINING TO DRILLING OF DISPOSAL AND OBSERVATION WELLS, DISPOSAL PROCEDURES FOR BRINES AND MINERALIZED WATERS INTO WELLS AND PLUGGING REQUIREMENTS FOR ABANDONED WELLS ARE TO BE ENFORCED AS LISTED.
159 KANSAS WATER QUALITY CRITERIA	ADOPTED APRIL 13, 1973, EFFECTIVE NOVEMBER 26, 1973	<ul style="list-style-type: none"> ● THE WASTE EFFLUENTS FROM THE THERMAL EOR FIELDS ARE NOT TO IMPACT THE EXISTING QUALITY OF STATE WATERS.
KANSAS PERMITS, SPILLS, AND GRANT REGULATIONS	KSA 28-16-57, EFFECTIVE APRIL 29, 1974	<ul style="list-style-type: none"> ● THE STATE PERMIT AND MONITORING REGULATIONS PERTAINING TO UNDERGROUND DISCHARGES OF WASTEWATERS FROM THE TEST SITES ARE GOVERNED BY THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM REQUIREMENTS.
KANSAS SOLID WASTE MANAGEMENT STANDARDS AND REGULATIONS	EFFECTIVE JANUARY 1, 1972	<ul style="list-style-type: none"> ● THE STATE STANDARDS FOR THE STORAGE OF SOLID WASTES AT THE TEST SITES ARE TO BE OBSERVED AS OUTLINED IN SECTION 28-29-8.

7. ARKANSAS

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
ARKANSAS AIR QUALITY STANDARDS	-	<ul style="list-style-type: none"> THE EMISSIONS FROM THERMAL EOR PROCESSES ARE NOT TO IMPACT THE STATE PRIMARY AND SECONDARY AMBIENT AIR QUALITY STANDARDS (SEE APPENDIX E) BEYOND THE PROPERTY LINE OF THE SITES.
ARKANSAS REGULATION ESTABLISHING WATER QUALITY STANDARDS FOR SURFACE WATERS	ADOPTED MAY 26, 1967; EFFECTIVE SEPTEMBER 28, 1973	<ul style="list-style-type: none"> THE THERMAL EOR PROCESSES ARE REQUIRED NOT TO DEGRADE THE EXISTING QUALITY OF STATE WATERS THROUGH ACCIDENTAL SPILLS OF ONSITE STORED OILS.
ARKANSAS WATER AND AIR POLLUTION CONTROL ACT	-	<ul style="list-style-type: none"> THE STATE PERMIT AND MONITORING REGULATIONS PERTAINING TO UNDERGROUND WASTE LIQUID DISCHARGES FROM THE THERMAL EOR TEST SITES ARE GOVERNED BY THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM REQUIREMENTS.
160 ARKANSAS SOLID WASTE DISPOSAL REGULATIONS	EFFECTIVE JUNE 28, 1973	<ul style="list-style-type: none"> ALL SOLID WASTES GENERATED AT THERMAL EOR SITES ARE TO BE COLLECTED, TRANSPORTED, AND DISPOSED OF IN A MANNER TO PREVENT HEALTH AND SAFETY HAZARDS AND UNACCEPTABLE ENVIRONMENTAL NUISANCES.
REGULATION FOR THE PREVENTION OF POLLUTION BY SALT WATER AND OTHER OIL FIELD WASTES PRODUCED BY WELLS IN NEW FIELDS OR POOLS	EFFECTIVE OCTOBER 13, 1958	<ul style="list-style-type: none"> THE DISPOSAL PROCEDURES FOR BRINES AND OTHER OIL FIELD WASTES ARE SUBJECTED TO REGULATION NO. 1.

8. COLORADO

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
COLORADO AIR POLLUTION CONTROL REGULATIONS: REGULATION NO. 1 - PARTICULATES, SMOKES, AND SULFUR OXIDES	EFFECTIVE FEBRUARY 1, 1972; LAST AMENDED AUGUST 11, 1977	<ul style="list-style-type: none"> • THE ALLOWABLE EMISSIONS OF PARTICULATE MATTER FROM STEAM GENERATORS OF HEAT INPUT UP TO 1 AND 10 MILLION Btu PER HOUR ARE 0.5 AND 0.27 ppm Btu RESPECTIVELY. • THE ALLOWABLE EMISSIONS OF SULFUR DIOXIDE FROM STEAM GENERATORS BURNING LIQUID FUELS IS NOT TO EXCEED 0.8 ppm Btu OF HEAT INPUT AND 1.2 ppm Btu COAL HEAT INPUT. • THE EMISSIONS OF ODOROUS AIR CONTAMINANTS FROM THERMAL EOR FIELDS ARE NOT PERMITTED. • THE EMISSIONS FROM THE THERMAL EOR FIELDS ARE NOT TO DEGRADE THE AMBIENT AIR QUALITY STANDARDS (SEE APPENDIX E) BEYOND THE PROPERTY LINE
COLORADO REGULATIONS FOR THE STATE DISCHARGE PERMIT SYSTEM	EFFECTIVE JANUARY 31, 1975; LAST AMENDED FEBRUARY 7, 1978	<ul style="list-style-type: none"> • THE STATE PERMIT AND MONITORING REGULATIONS PERTAINING TO WASTE LIQUID UNDERGROUND DISCHARGES ARE GOVERNED BY THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES) REQUIREMENTS.
COLORADO WATER QUALITY STANDARDS	EFFECTIVE JULY 20, 1978	<ul style="list-style-type: none"> • THE THERMAL EOR FIELD TESTS ARE REQUIRED NOT TO IMPACT THE EXISTING SURFACE WATER QUALITY OF THE STATE WATERS THROUGH ACCIDENTAL SPILLS.
COLORADO SOLID WASTE REGULATIONS	ADOPTED FEBRUARY 16, 1972; EFFECTIVE APRIL 1, 1972	<ul style="list-style-type: none"> • THE SOLID WASTES GENERATED AT THERMAL EOR SITES ARE TO BE COLLECTED, STORED, TRANSPORTED, AND DISPOSED OF IN ACCORDANCE WITH THE STATE REGULATIONS.

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9. ILLINOIS

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
ILLINOIS STATIONARY SOURCES STANDARDS	EFFECTIVE APRIL 15, 1972; AMENDED DECEMBER 31, 1977	<ul style="list-style-type: none"> ● THE EMISSIONS OF PARTICULATE MATTER FROM STEAM GENERATORS USING SOLID FUEL EXCLUSIVELY AND LOCATED IN THE CHICAGO MAJOR METROPOLITAN AREA, ARE NOT TO EXCEED 0.1 ppm Btu HEAT INPUT IN ANY ONE-HOUR PERIOD (CONDITIONAL). ● THE EMISSIONS OF PARTICULATE MATTER FROM STEAM GENERATORS UP TO 1.0 MILLION Btu PER HOUR CAPACITY USING SOLID FUEL EXCLUSIVELY AND LOCATED OUTSIDE THE CHICAGO METROPOLITAN AREA, ARE NOT TO EXCEED 1.0 ppm Btu IN ANY ONE-HOUR PERIOD. THE PARTICULATE EMISSION LIMITS FOR HIGHER CAPACITY BOILERS ARE TO BE CALCULATED MATHEMATICALLY (CONDITIONAL). ● THE EMISSIONS OF PARTICULATES FROM STEAM GENERATORS USING LIQUID FUEL EXCLUSIVELY ARE NOT TO EXCEED 0.10 ppm Btu HEAT INPUT IN ANY ONE-HOUR PERIOD. ● THE EMISSIONS OF PARTICULATES FROM STEAM GENERATORS USING MORE THAN ONE TYPE OF FUEL ARE NOT TO EXCEED A VALUE WHICH IS TO BE MATHEMATICALLY CALCULATED. ● THE EMISSIONS OF SULFUR DIOXIDE EMISSIONS FROM STEAM GENERATORS USING SOLID FUEL EXCLUSIVELY ARE NOT TO EXCEED 1.8 ppm Btu OF HEAT INPUT IN ANY ONE-HOUR PERIOD.

9. ILLINOIS
(Continued)

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
ILLINOIS STATIONARY SOURCES STANDARDS	EFFECTIVE APRIL 15, 1972; AMENDED DECEMBER 31, 1977	<ul style="list-style-type: none"> • THE EMISSIONS OF SULFUR DIOXIDE EMISSIONS FROM STEAM GENERATORS USING RESIDUAL FUEL OIL ARE NOT TO EXCEED IN ANY ONE-HOUR PERIOD 1.0 ppm Btu OF HEAT INPUT AND 3.0 ppm Btu HEAT INPUT WHEN DISTILLATE FUEL IS USED. • THE AIR POLLUTION CONTROL REGULATIONS FOR THE HANDLING OF RECOVERED HEAVY OIL-WATER SEPARATION SYSTEMS ARE TO BE EMPLOYED. • THE EMISSIONS OF CARBON MONOXIDE FROM STEAM GENERATORS ARE NOT TO EXCEED 200 ppm CORRECTED TO 50 PERCENT AIR.
ILLINOIS AIR QUALITY STANDARDS	ADOPTED MAY 5, 1973; LAST AMENDED DECEMBER 31, 1977	<ul style="list-style-type: none"> • THE EMISSIONS FROM THERMAL EOR FIELDS ARE REQUIRED NOT TO IMPACT THE STATE PRIMARY AND SECONDARY AMBIENT AIR QUALITY STANDARDS (SEE APPENDIX E) BEYOND THE PROPERTY LINE OF THE SITES.
ILLINOIS ODORS REGULATIONS	ADOPTED APRIL 13, 1972	<ul style="list-style-type: none"> • THE THERMAL EOR TEST SITES ARE SUBJECTED TO THESE REGULATIONS WHICH FORBID THE GENERATION OF OBJECTIONAL ODORS AROUND THE TEST FACILITIES.
ILLINOIS WATER POLLUTION CONTROL RULES	ADOPTED MARCH 7, 1972; LAST AMENDED JUNE 22, 1978	<ul style="list-style-type: none"> • THE THERMAL EOR PROJECTS ARE REQUIRED TO ADHERE TO RULES AND REGULATIONS FOR CONTINUED MAINTENANCE OF CERTAIN SPECIFIED BENEFICIAL USES OF STATE WATER BODIES.

9. ILLINOIS
(Continued)

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
ILLINOIS WATER POLLUTION CONTROL RULES	ADOPTED MARCH 7, 1972; LAST AMENDED JUNE 22, 1978	<ul style="list-style-type: none"> ● THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES) PERMIT REGULATIONS FOR UNDERGROUND DISPOSAL OF CERTAIN LIQUID WASTES FROM THERMAL EOR SITES ARE TO BE EMPLOYED.
ILLINOIS ENVIRONMENTAL PROTECTION ACT	AMENDED JANUARY 1, 1978	<ul style="list-style-type: none"> ● THE NOISE GENERATED DUE TO THE OPERATION OF VARIOUS PIECES OF EQUIPMENT AT THE THERMAL EOR SITES IS NOT TO INTERFERE WITH THE OUTDOOR ACTIVITIES BEYOND THE SITE BOUNDRIES.

10. MISSISSIPPI

CITATION IDENTIFICATION/TITLE	DATES/IDENTIFICATION	APPLICABILITY TO THERMAL EOR PROCESSES
MISSISSIPPI AIR POLLUTION CONTROL REGULATIONS	ADOPTED MAY 11, 1972; AMENDED MAY 27, 1975	<ul style="list-style-type: none"> THE THERMAL EOR FIELDS ARE NOT TO RELEASE INTO THE ATMOSPHERE ANY CONTAMINANT IN A SUFFICIENT AMOUNT WHICH CAN BE INJURIOUS TO THE HUMAN, ANIMAL, OR PLANT KINGDOM OR BE A PUBLIC NUISANCE. THE ALLOWABLE EMISSIONS OF PARTICULATE MATTER FROM STEAM GENERATORS OF HEAT INPUT RATES OF 10 AND 50 MILLION Btu PER HOUR ARE 0.6 AND 0.5 POUNDS RESPECTIVELY. FOR THE STEAM GENERATORS WITHIN THIS RANGE, THE EMISSION LIMITS ARE TO BE INTERPOLATED. THE OPACITY OF THE SMOKE PRODUCED, AS A RESULT OF COMBUSTION OF FUEL OIL, IS NOT TO BE DARKER THAN NUMBER 2 ON THE RINGLEMANN CHART OR FORTY (40) PERCENT EQUIVALENT OPACITY. THE EMISSIONS OF SULFUR DIOXIDE FROM STEAM GENERATORS ARE NOT TO EXCEED 2.4 ppm Btu HEAT INPUT.
MISSISSIPPI WATER QUALITY CRITERIA	ADOPTED APRIL 24, 1973; AMENDED APRIL 12, 1977	<ul style="list-style-type: none"> THE ACCIDENTAL SPILLS OF ONSITE STORED HEAVY OILS FROM THE FIELDS ARE NOT TO AFFECT THE EXISTING SURFACE WATER QUALITY OF THE STATE WATERS.
MISSISSIPPI NPDES REGULATIONS	EFFECTIVE MAY 1, 1974; AMENDED MARCH 11, 1975	<ul style="list-style-type: none"> THE NPDES PERMITS ARE NOT REQUIRED. HOWEVER, STATE PERMITS WILL BE REQUIRED AS EXPLAINED UNDER THESE REGULATIONS.
MISSISSIPPI SOLID WASTES DISPOSAL ACT OF 1974 AND MISSISSIPPI SOLID WASTE REGULATIONS	APPROVED APRIL 24, 1974; AMENDED 1976	<ul style="list-style-type: none"> THE SOLID WASTES FROM THE THERMAL EOR SITES ARE TO BE HANDLED, COLLECTED, STORED, TRANSPORTED, AND DISPOSED OF IN ACCORDANCE WITH THESE REGULATIONS.

ADDENDUM C:

KERN COUNTY ENVIRONMENTAL REGULATORY REQUIREMENTS
TO THERMAL EOR PROCESSES

KERN COUNTY ENVIRONMENTAL REGULATORY REQUIREMENTS TO THERMAL EOR PROCESSES

CITATION IDENTIFICATION	PERMIT REQUIREMENTS	CITATION DESCRIPTION
<p>Rules and Regulations: Kern County Air Pollution Control District</p> <p>167</p>	<p>New Source Review Permits are required for sources with pollutants greater than 15 lb/hour. Air quality review is required. Scrubbers are required on an unofficial basis only for new or modified steam generators.</p>	<ul style="list-style-type: none"> ● <u>Rule 404</u>: Particulate matter discharges in the Valley Basin must not exceed 0.1 grains per cubic foot at standard conditions. ● <u>Rule 404.1</u>: Particulate matter discharges in the Desert Basin must not exceed 0.2 grains per cubic foot at standard conditions. ● <u>Rule 407</u>: Sulfur compounds must not exceed 0.2 percent by volume calculated as sulfur dioxide. ● <u>Rule 407.2</u>: Combustion contaminants must not exceed 0.1 grains per cubic foot gas calculated to 12 percent CO₂ at standard conditions. ● <u>Rule 408</u>: Emission limitations from steam generators are as follows: <ul style="list-style-type: none"> SO₂: 200 lbs per hour NO₂: 140 lbs per hour Combustion Contaminants: 10 lbs per hour

KERN COUNTY ENVIRONMENTAL REGULATORY REQUIREMENTS TO THERMAL EOR PROCESSES

CITATION IDENTIFICATION	PERMIT REQUIREMENTS	CITATION DESCRIPTION
<p>Regulations: Waste Discharge Requirements, National Pollutant Discharge Elimination System</p> <p>The Porter-Cologne Water Quality Act</p> <p>California Laws for Conservation of Petroleum and Gas</p> <p>California Administrative and Water Code; Health and Safety Code, Section 25100-25185</p> <p>Noise Control Requirements</p> <p>Zoning Regulations</p>	<p>NPDES permit administered through the California Water Quality Control Boards (Section 3.2.1)</p> <p>The permit requirements are administered through the California State Water Resources Control Boards.</p> <p>Permits for reinjection of wastes into underground formations are required.</p> <p>Permits for the land disposal of industrial and hazardous wastes are required.</p> <p>Resolution Numbers 46-75 and 75-246</p> <p>Article 26, Sections 7241-7244</p>	<ul style="list-style-type: none"> • In central Kern County, wastewater is reinjected into the formations. Western Kern County allows discharges to percolation ponds, however, the effluent limits vary from field to field. • The waste discharge requirements for the heavy oil fields are required to comply with all water quality laws and regulations under this act (Section 3.2.1). • The Division of Oil and Gas is responsible for maintaining the required quality of the groundwaters due to any underground waste disposal activities. • The disposal procedures for industrial (oily wastes) and the hazardous wastes from the thermal EOR sites are set forth by the State Water Quality Control Board and the State Department of Public Health. • Utilize good land use planning principles to reduce noise emissions and employ the best available methods of noise control to thermal EOR operations. • The Land Use Zoning Ordinance regulating the surface uses of land for thermal EOR operations are to be observed as stated under this article.

ADDENDUM D:

AMBIENT AIR QUALITY STANDARDS FOR U.S. AND THE MAJOR STATES
WHERE TARGET RESERVOIRS ARE LOCATED

AMBIENT AIR QUALITY STANDARDS FOR U.S. AND THE MAJOR STATES
WHERE TARGET RESERVOIRS ARE LOCATED

GOVERNMENT AUTHORITY	SULFUR DIOXIDE			CARBON MONOXIDE			NITROGEN DIOXIDE		
	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME
Federal	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 365 $\mu\text{g}/\text{M}^3$ (0.14 ppm) -	- - 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour 3-Hour	40* mg/M^3 10* mg/M^3 (9 ppm) -	40* mg/M^3 10* mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
California	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 131 $\mu\text{g}/\text{M}^3$ (0.05 ppm) -	- - 1310 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour 1-Hour	46 mg/M^3 (40 ppm) 10 mg/M^3 (9 ppm) 11 mg/M^3 (10 ppm)	46 mg/M^3 (40 ppm) 10 mg/M^3 (9 ppm) 11 mg/M^3 (10 ppm)	1-Hour 8-Hour 12-Hour	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
Texas	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 365 $\mu\text{g}/\text{M}^3$ (0.14 ppm) -	- - 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour 3-Hour	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
Louisiana	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 365 $\mu\text{g}/\text{M}^3$ (0.14 ppm) -	60 $\mu\text{g}/\text{M}^3$ (0.02 ppm) 260 $\mu\text{g}/\text{M}^3$ (0.10 ppm) 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour 3-Hour	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
Wyoming	60 $\mu\text{g}/\text{M}^3$ (0.02 ppm) 260 $\mu\text{g}/\text{M}^3$ (0.10 ppm) -	- - 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour 3-Hour	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
Arkansas	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 365 $\mu\text{g}/\text{M}^3$ (0.14 ppm) -	- - 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
Mississippi	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 365 $\mu\text{g}/\text{M}^3$ (0.14 ppm) -	60 $\mu\text{g}/\text{M}^3$ (0.02 ppm) 260 $\mu\text{g}/\text{M}^3$ (0.10 ppm) 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour 3-Hour	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM AAM -
Oklahoma	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 365 $\mu\text{g}/\text{M}^3$ (0.14 ppm) -	- - 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour 3-Hour	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
Kansas	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 365 $\mu\text{g}/\text{M}^3$ (0.14 ppm) -	- - 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
Illinois	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 365 $\mu\text{g}/\text{M}^3$ (0.14 ppm) -	- - 1300 $\mu\text{g}/\text{M}^3$ (0.5 ppm)	AAM 24-Hour 3-Hour	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	- - -	AAM - -
Colorado	80 $\mu\text{g}/\text{M}^3$ (0.03 ppm) - -	- 260 $\mu\text{g}/\text{M}^3$ (0.09 ppm) 1300 $\mu\text{g}/\text{M}^3$ (0.45 ppm)	AAM 24-Hour 3-Hour	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) 170	40 mg/M^3 (35 ppm) 10 mg/M^3 (9 ppm) -	1-Hour 8-Hour -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	100 $\mu\text{g}/\text{M}^3$ (0.05 ppm) - -	AAM - -

Notes:

*Not to be exceeded more than once/year.
AAM = Annual Arithmetic Mean

AMBIENT AIR QUALITY STANDARDS FOR U.S. AND THE MAJOR STATES
WHERE TARGET RESERVOIRS ARE LOCATED
(Continued)

GOVERNMENT AUTHORITY	PHOTOCHEMICAL OXIDANTS			NONMETHANE HYDROCARBONS			SUSPENDED PARTICULATES		
	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME
Federal	160* $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	160* $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	1-Hour -	160* $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	160* $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	3-Hour (6-9 am) -	75 $\mu\text{g}/\text{M}^3$ 260* $\mu\text{g}/\text{M}^3$	60 $\mu\text{g}/\text{M}^3$ 150* $\mu\text{g}/\text{M}^3$	AGM 24-Hour
California	200 $\mu\text{g}/\text{M}^3$ (0.10 ppm) -	- -	1-Hour -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	3-Hour (6-9 am) -	60 $\mu\text{g}/\text{M}^3$ 100 $\mu\text{g}/\text{M}^3$	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$	AGM 24-Hour
Texas	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) - -	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) - -	1-Hour - -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) - -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) - -	3-Hour (6-9 am) - -	75 $\mu\text{g}/\text{M}^3$ 260 $\mu\text{g}/\text{M}^3$ -	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$ 1300 $\mu\text{g}/\text{M}^3$	AGM 24-Hour 3-Hour
Louisiana	58.8 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 98 $\mu\text{g}/\text{M}^3$ (0.05 ppm) 160 $\mu\text{g}/\text{M}^3$ (0.08 ppm)	58.8 $\mu\text{g}/\text{M}^3$ (0.03 ppm) 98 $\mu\text{g}/\text{M}^3$ (0.05 ppm) 160 $\mu\text{g}/\text{M}^3$ (0.08 ppm)	AAV 4-Hour 1-Hour	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) - -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) - -	3-Hour (6-9 am) - -	75 $\mu\text{g}/\text{M}^3$ 260 $\mu\text{g}/\text{M}^3$ -	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$ -	AGM 24-Hour -
Wyoming	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	- -	1-Hour -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	- -	3-Hour (6-9 am) -	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$	- -	AGM 24-Hour
Arkansas	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	- -	1-Hour -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	- -	3-Hour (6-9 am) -	75 $\mu\text{g}/\text{M}^3$ 260 $\mu\text{g}/\text{M}^3$	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$	AGM 24-Hour
Mississippi	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	- -	1-Hour -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	- -	3-Hour (6-9 am) -	75 $\mu\text{g}/\text{M}^3$ 260 $\mu\text{g}/\text{M}^3$	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$	AGM 24-Hour
Oklahoma	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) - -	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) - -	1-Hour - -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) - -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) - -	3-Hour (6-9 am) - -	75 $\mu\text{g}/\text{M}^3$ 260 $\mu\text{g}/\text{M}^3$ -	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$ 1300 $\mu\text{g}/\text{M}^3$	AGM 24-Hour 3-Hour
Kansas	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	1-Hour -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	3-Hour (6-9 am) -	75 $\mu\text{g}/\text{M}^3$ 260 $\mu\text{g}/\text{M}^3$	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$	AGM 24-Hour
Illinois	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	- -	1-Hour -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	3-Hour (6-9 am) -	75 $\mu\text{g}/\text{M}^3$ 260 $\mu\text{g}/\text{M}^3$	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$	AGM 24-Hour
Colorado	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	160 $\mu\text{g}/\text{M}^3$ (0.08 ppm) -	1-Hour -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	160 $\mu\text{g}/\text{M}^3$ (0.24 ppm) -	3-Hour (6-9 am) -	75 $\mu\text{g}/\text{M}^3$ 260 $\mu\text{g}/\text{M}^3$	60 $\mu\text{g}/\text{M}^3$ 150 $\mu\text{g}/\text{M}^3$	AGM 24-Hour

Notes:

*Not to be exceeded more than once/year.

AGM = Annual Geometric Mean

AAV = Annual Average Value

AMBIENT AIR QUALITY STANDARDS FOR U.S. AND THE MAJOR STATES
WHERE TARGET RESERVOIRS ARE LOCATED
(Continued)

GOVERNMENT AUTHORITY	LEAD			SULFATE			HYDROGEN SULFIDE		
	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME
Federal	1.5 $\mu\text{g}/\text{M}^3$	-	30-Day	Being Considered	Being Considered	Being Considered	-	-	-
California	1.5 $\mu\text{g}/\text{M}^3$	-	30-Day	25 $\mu\text{g}/\text{M}^3$	-	24-Hour	42 $\mu\text{g}/\text{M}^3$ (0.03 ppm)	-	1-Hour
Texas	-	-	-	-	-	-	(0.08 ppm)	(0.12 ppm)	30-Minutes
Louisiana	-	-	-	4 $\mu\text{g}/\text{M}^3$	-	AAV	-	-	-
Wyoming	-	-	-	0.5 mg 100 cm^2/day	-	30-Day	70* $\mu\text{g}/\text{M}^3$ 40† $\mu\text{g}/\text{M}^3$	-	30-Minutes 30-Minutes
Arkansas	-	-	-	-	-	-	-	-	-
Mississippi	-	-	-	-	-	-	(0.05* ppm) (0.03† ppm)	-	30-Minutes 30-Minutes
Oklahoma	-	-	-	-	-	-	-	-	-
Kansas	-	-	-	-	-	-	-	-	-
Illinois	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-

GOVERNMENT AUTHORITY	SOILING INDEX/ COEFFICIENT OF HAZE			SETTLABLE PARTICULATES		
	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME	PRIMARY STANDARDS	SECONDARY STANDARDS	AVERAGING TIME
Federal	-	-	-	-	-	-
California	-	-	-	-	-	-
Texas	-	-	-	-	-	-
Louisiana	0.75 COH/ 1000 LF 0.6 COH/ 1000 LF 1.5 COH/ 1000 LF	-	AAM AGM 24-Hour	20 tons/ sq mile - -	- - -	1-Month - -
Wyoming	0.4 COH 1000 LF -	-	AGM -	5 [§] g/m ² 10 [§] g/m ²	- -	1-Month 1-Month
Arkansas	-	-	-	-	-	-
Mississippi	-	-	-	-	-	-
Oklahoma	-	-	-	-	-	-
Kansas	-	-	-	-	-	-
Illinois	-	-	-	-	-	-
Colorado	-	-	-	-	-	-

Notes:

*Not to be exceeded more than 2 times/year.

†Not to be exceeded more than 2 times in 5 consecutive days.

§Includes background of 1.7 gms/M².

AAV = Annual Average Value

AAM = Annual Arithmetic Mean

AGM = Annual Geometric Mean

COH = Coefficient of Haze