

Table VI-8 Weighted Average Regional Costs of Drilling Waste Management  
for Model Projects Under Alternative Waste Management Scenarios  
(Dollars per Well)

Model project/ zone	Baseline	Intermediate		Subtitle C 10% and Subtitle C-1 10%	Subtitle C 70% and Subtitle C-1 70%
		10%	70%		
Appalachian	\$ 9,465	\$ 9,602	\$10,420	\$12,799	\$ 32,801
Gulf	24,582	25,756	32,796	30,848	68,440
Midwest	6,014	6,219	7,447	10,138	34,880
Plains	11,442	11,852	14,312	16,073	43,858
Texas/Oklahoma	17,398	18,258	23,418	21,163	43,755
Northern Mountain	24,186	25,495	33,348	31,965	78,636
Southern Mountain	22,711	23,511	28,594	29,689	71,555
West Coast	2,919	3,258	5,290	6,521	28,135
Alaska	28,779	30,277	39,266	35,333	74,661
Lower 48 States	15,176	15,964	20,964	19,837	47,800

NOTE: Costs in 1985 dollars, based on 1985 cost factors.

Source: ERG estimates.

Table VI-9 Weighted Average Unit Costs of Produced Water Management  
for Model Projects under Alternative Waste Management Scenarios  
(Dollars per Barrel of Water)

Model project/ zone	Baseline	Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	\$0.52	\$0.57	\$0.94	\$0.80	\$2.51	\$0.67	\$1.57
Gulf	0.08	0.06	0.10	0.16	0.65	0.15	0.57
Midwest	0.14	0.14	0.14	0.22	0.65	0.15	0.20
Plains	0.16	0.16	0.16	0.24	0.74	0.20	0.47
Texas/Oklahoma	0.13	0.13	0.13	0.20	0.61	0.15	0.31
Northern Mountain	0.07	0.07	0.07	0.11	0.36	0.09	0.22
Southern Mountain	0.13	0.13	0.13	0.19	0.55	0.14	0.24
West Coast	0.04	0.04	0.04	0.08	0.34	0.07	0.26
Alaska	0.31	0.31	0.31	0.46	1.42	0.34	0.56
Lower 48 States	0.11	0.11	0.12	0.18	0.62	0.15	0.35

NOTE: Waste management costs applied to both oil and gas production wastes.  
Costs in 1985 dollars.

Source: ERG estimates.

Table VI-10 Impact of Waste Management Costs on Model Projects: Comparisons  
of After-Tax Internal Rate of Return<sup>a</sup>  
(%)

Model project/ zone	Baseline	Alternative waste management scenarios					
		Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	10.3%	10.2%	8.9%	8.9%	0.9%	9.2%	3.6%
Gulf-gas	22.9	22.8	22.5	22.5	20.7	22.6	20.7
Gulf-oil	36.4	36.2	34.5	33.2	15.6	33.5	17.9
Midwest	12.1	12.1	11.8	8.2	-19.4	10.9	5.1
Plains	9.0	9.0	8.6	6.9	-5.6	7.7	0.0
Texas/Oklahoma-gas	19.6	19.5	19.3	19.4	18.3	19.4	18.5
Texas/Oklahoma-oil	29.6	29.5	28.9	27.4	14.6	28.4	22.1
Northern Mountain	19.6	19.5	19.0	18.2	10.1	18.6	13.1
Southern Mountain	9.2	9.2	9.0	8.3	3.3	8.7	6.3
West Coast	35.0	35.0	34.5	33.6	25.4	33.8	26.9
Alaska	10.9	10.9	10.9	10.8	10.6	10.9	10.8
Lower 48 States	28.9	28.8	28.0	26.6	13.0	27.6	19.7

NOTE: Both drilling and production wastes regulated.

<sup>a</sup> Internal rate of return defined as return after corporate taxes, to total invested capital including both equity and debt.

Source: ERG estimates.

Table VI-11 Impact of Waste Management Costs on Model Projects:  
Increase in Total Cost of Production<sup>a</sup>  
(Dollars per Barrel of Oil Produced)

Model project/ zone	Total baseline cost	Increase in cost under alternative waste management scenarios					
		Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	\$16.22	\$ 0.05	\$ 0.44	\$ 0.45	\$ 3.24	\$ 0.33	\$ 2.35
Gulf-gas	9.45	0.01	0.03	0.03	0.20	0.03	0.20
Gulf-oil	15.65	0.01	0.17	0.40	2.85	0.36	2.48
Midwest	19.45	0.01	0.07	1.11	8.31	0.34	2.12
Plains	18.46	0.02	0.03	0.51	3.69	0.33	2.46
Texas/Oklahoma-gas	7.61	0.01	0.02	0.02	0.11	0.02	0.09
Texas/Oklahoma-oil	14.86	0.01	0.07	0.40	1.24	0.20	2.74
Northern Mountain	15.51	0.02	0.12	0.36	2.56	0.23	1.65
Southern Mountain	18.05	0.01	0.08	0.29	2.01	0.16	0.99
West Coast	13.19	0.00	0.07	0.23	1.68	0.18	1.34
Alaska	15.02	0.00	0.00	0.01	0.10	0.00	0.03
Lower 48 States	14.11	0.01	0.11	0.40	2.88	0.20	1.55

<sup>a</sup> Total cost of production defined to include capital costs, operating costs, lease bonus costs, and pollution control costs, as well as transfer payments such as Federal income taxes, royalties, and State severance taxes.

Source: ERG estimates.

project after-tax internal rates of return decline under the waste management scenarios to the 13.0 to 28.8 percent range for the Lower 48 average.

The after-tax cost of producing hydrocarbons can also increase substantially. As Table VI-11 shows, these costs can increase by up to \$2.98 per barrel of oil equivalent (BOE), a 20 percent increase over baseline costs. The impacts of these cost increases on a national level are described further below.

## REGIONAL- AND NATIONAL-LEVEL COMPLIANCE COSTS OF THE WASTE MANAGEMENT SCENARIOS

The cost of waste management for the typical projects under each waste management scenario (see Tables VI-8 and VI-9) were used in conjunction with annual drilling (API 1986) and production levels (API 1987c) to estimate the regional- and national-level annual costs of the waste management scenarios. These costs, which include both drilling and production waste disposal costs, are presented in Table VI-12. National-level costs range from \$49 million in the Intermediate 10% Scenario to more than \$12.1 billion in the Subtitle C 70% Scenario.

The costs presented in Table VI-12 do not include the effects of closures. They are based on 1985 drilling and production levels, assuming that no activities are curtailed because of the requirements of the waste management scenarios. In reality, each of the waste management scenarios would result in both the early closure of existing projects and the cancellation of new projects. To the extent that the level of oil and gas activity declines, total aggregate compliance costs incurred under each waste management scenario will be lower, but there will be other costs to the national economy caused by lower levels of oil production. These effects are described more fully below.

Table VI-12 Annual Regional and National RCRA Compliance Cost of Alternative Waste Management Scenarios  
(Millions of Dollars)

Model project/ zone	Waste management scenarios					
	Intermediate		Subtitle C		Subtitle C-1	
	10%	70%	10%	70%	10%	70%
Appalachian	\$5	\$43	\$57	\$403	\$47	\$328
Gulf	8	94	200	1,417	180	1,239
Midwest	1	6	120	870	31	185
Plains	2	17	126	907	77	576
Texas/Oklahoma	26	181	879	6,156	442	2,873
Northern Mountains	3	19	94	677	55	404
Southern Mountains	3	21	92	643	47	297
West Coast	1	36	126	936	97	736
Alaska	0	2	17	118	5	34
Lower 48 States	49	418	1,693	12,007	975	6,637
National Total	49	420	1,710	12,125	980	6,671

NOTE: Figures represent before-tax total annual increase in waste management cost over baseline costs at 1985 levels of drilling and production, without adjusting for decreases in industry activity caused by higher production costs at affected sites. Column totals may differ because of independent rounding. Base year for all costs is 1985.

## CLOSURE ANALYSIS FOR EXISTING WELLS

The potential of the waste management scenarios to shut down existing producing wells was estimated using the model facility approach. The model facility simulations for existing projects, however, do not include the initial capital cost of leasing and drilling the production well. For the analysis of existing projects, it is assumed that these costs have already been incurred. The projects are simulated for their operating years. If operating revenues exceed operating costs, the projects remain in production.

Closures of existing wells are estimated by using a variable called the economic limit (i.e., a level of production below which the project cannot continue to operate profitably). Under the waste management scenarios, produced water disposal costs are higher and, therefore, the economic limit is higher. Some projects that have production levels that exceed the baseline economic limit would fall below the economic limit under the alternative waste management scenarios. Those projects not meeting this higher level of production can be predicted to close. This analysis was conducted only with respect to stripper wells. To the extent that certain high-volume, low-margin wells may also be affected, the analysis may understate short-term project closures.

The economic limit analysis requires information on the distribution of current production levels across wells. Because of the lack of data for most States, the economic limit analysis is presented here only for Texas and on a national level. The 1985 distribution of production by volume size class for Texas and for the Nation as a whole is shown in Table VI-13.

Table VI-14 displays the results of the economic limit analysis. Under baseline assumptions, the representative Lower 48 project requires 2.40 barrels per day to remain in operation. The economic limit for

Table VI-13 Distribution of Oil Production  
Across Existing Projects, 1985

Region	Production Interval (BOPD) bbl/d	Number of Wells	Total Oil Production 1000 bb/d
National	0 - 1	112,000	71
	1 - 2	112,000	165
	2 - 3	78,000	206
	3 - 4	65,000	231
	4 - 5	20,000	92
	5 - 6	27,000	154
	6 - 7	21,000	142
	7 - 8	16,000	119
	8 - 9	15,000	129
	9 - 10	9,000	63
	Total	475,000	1,371
Texas	<1	42,881	21
	1.0 - 1.5	15,018	19
	1.6 - 2.5	20,856	43
	2.6 - 3.5	14,018	43
	3.6 - 4.5	11,303	46
	4.6 - 5.5	9,665	49
	5.6 - 6.5	7,638	46
	6.6 - 7.5	6,201	44
	7.6 - 8.6	5,420	44
	9.6 - 1.05	4,441	45
	Total		142,743
	446		

Sources: "The Effect of Lower Oil Prices on Production From Proved U.S. Oil Reserves," Energy and Environmental Analysis, Inc., February 1987, taken from Figure 2-2. Indicators: A Monthly Data Review-April 1986, Railroad Commission of Texas, April 1986.



Table VI-14 Impact of Waste Management Cost on Existing Production

Region	Scenario	Economic limit (bbl/d)	Lower-range effects				Upper-range effects			
			Well closures		Lost production		Well closures		Lost production	
			Number of wells	Percent of wells	1000 bbl/d	Percent of production	Number of wells	Percent of wells	1000s bbl/d	Percent of production
Texas										
	Baseline <sup>a</sup>	2.30								
	Intermediate 10%	2.32	42	0.02	0.09	0.00	6,562	3.29	5.60	0.24
	Intermediate 70%	2.32	292	0.15	0.60	0.03	45,931	23.05	39.22	1.67
	Subtitle C 10%	3.89	2,260	1.13	6.92	0.30	8,780	4.41	12.00	0.53
	Subtitle C 70%	3.89	15,818	7.94	48.41	2.07	61,457	30.84	87.04	3.71
	Subtitle C-1 10%	2.73	740	0.37	1.84	0.08	7,259	3.64	7.36	0.31
	Subtitle C-1 70%	2.73	5,177	2.60	12.87	0.55	50,816	25.50	51.49	2.20
National: Lower 48 States										
	Baseline <sup>b</sup>	2.40								
	Intermediate 10%	2.42	156	0.03	0.41	0.00	20,652	3.33	21.00	0.25
	Intermediate 70%	2.42	1,092	0.18	2.88	0.03	144,564	23.31	148.45	1.75
	Subtitle C 10%	4.20	11,580	1.87	37.32	0.44	32,076	5.17	58.00	0.68
	Subtitle C 70%	4.20	81,060	13.07	261.23	3.07	224,532	36.20	406.79	4.79
	Subtitle C-1 10%	3.01	4,745	0.77	13.00	0.15	25,241	4.07	33.00	0.39
	Subtitle C-1 70%	3.01	33,215	5.36	88.14	1.04	176,687	28.49	233.70	2.75

<sup>a</sup> Baseline production level is 2.3 million bbl/d; baseline well total is 199,000.

<sup>b</sup> Baseline production level is 8.6 million bbl/d; baseline well total is 620,000.

Source: ERG estimates.

affected operations rises to 3.01 to 4.20 barrels per day under the waste management scenarios. The increase in the economic limit results in closures of from 0.03 percent to 36.20 percent of all producing wells.

The "lower-range effects" in Table VI-14 assume that only affected wells (i.e., wells generating hazardous produced waters) producing at levels between the baseline economic limit and the economic limit under the waste management scenarios will be closed. The "upper-range effects" assume that all affected wells producing at levels below the economic limit under the waste management scenarios will be closed, and are adjusted to account for the change in oil prices from 1985 to 1986.

Under the lower-range effects case, production losses are estimated at between 0.00 and 3.07 percent of total production. Under the upper-range effects assumptions, production closures range from 0.25 to 4.79 percent of the total. These results are indicative of the immediate, short-term impact of the waste management scenarios caused by well closures.

The results of the Texas simulation mirror those of the national-level analysis. This would be expected, since nearly 30 percent of all stripper wells are in Texas, and the State is, therefore, reflected disproportionately in the national-level analysis. Under the lower-range effects assumptions, Texas production declines between 0.00 and 2.07 percent. Under the upper-range effects assumptions, Texas production declines between 0.24 and 3.71 percent.

## THE INTERMEDIATE AND LONG-TERM EFFECTS OF THE WASTE MANAGEMENT SCENARIOS

### Production Effects of Compliance Costs

The intermediate and long-term effects of the waste management scenarios will exceed the short-term effects for two principal reasons.

First, the increases in drilling waste management cost, which do not affect existing producers, can influence new project decisions. Second, the higher operating costs due to produced water disposal requirements may result in some project cancellations because of the expectation of reduced profitability during operating years. Although such projects might be expected to generate profits in their operating years (and therefore might be expected to operate if drilled), the reduced operating profits would not justify the initial investment.

The intermediate and long-term production effects were estimated using Department of Energy (DOE) production forecasting models. As described above, an economic simulation model was used to calculate the increase in the cost of resource extraction under each waste management scenario. These costs were used in conjunction with the DOE FOSSIL2 model (DOE 1985) and the DOE PROLOG model (DOE 1982) to generate estimates of intermediate and long-term production effects of the waste management scenarios.

For the FOSSIL2 model, an estimate of the increase in resource extraction costs for each waste management scenario, based on model project analysis, was provided as an input. Simulations were performed to measure the impact of this cost increase on the baseline level of production.

For the PROLOG model, no new simulations were performed. Instead, results of previous PROLOG modeling were used to calculate the elasticity of supply with respect to price in the PROLOG model. The model project simulation results were used to calculate an oil price decline that would have the same impact as the cost increase occurring under each alternative waste management scenario. These price increases were used in conjunction with an estimate of the price elasticity of supply from the PROLOG model to estimate an expected decline in production for each waste management scenario.

Table VI-15 shows the results of this analysis. The long-term impacts of the waste management scenarios range from levels that are below the detection limits of the modeling system to declines in production ranging up to 32 percent in the year 2000, based on the PROLOG analysis. For the FOSSIL2 simulations, production declines were estimated to range from "not detectable" to 18 percent in the year 2000 and from "not detectable" to 29 percent in the year 2010.

#### Additional Impacts of Compliance Costs

The decline in U.S. oil production brought about by the cost of the waste management scenarios would have wide-ranging effects on the U.S. economy. Domestic production declines would lead to increased oil imports, a deterioration in the U.S. balance of trade, a strengthening of OPEC's position in world markets, and an increase in world oil prices. Federal and State revenues from leasing and from production and income taxes would decline. Jobs would be lost in the oil and gas drilling, servicing, and other supporting industries; jobs would be created in the waste management industries (e.g., contractors who drill and complete Class I injection wells).

It is beyond the scope of this report to fully analyze all of these and other macroeconomic effects. To illustrate the magnitude of some of these effects, however, five categories of impacts were defined and quantified (oil imports, balance of trade, oil price, Federal leasing revenues, and State production taxes). These are presented in Table VI-16. Measurable effects are evident for all but the lowest cost (Intermediate 10% Scenario).

The impacts of the waste management scenarios on the U.S. economy were analyzed utilizing the DOE FOSSIL2/WOIL modeling system. Cost increases for U.S. oil producers create a slight decrease in the world oil supply curve (i.e., the amount of oil that would be brought to market at any oil price declines). The model simulates the impact of this shift on the world petroleum supply, demand, and price.

Table VI-15 Long-Term Impacts on Production of Cost Increases  
under Waste Management Scenarios

Scenario	Estimated resource extraction cost increase (%)	Decline of domestic oil production in lower 48 States				
		Year 1990		Year 2000		Year 2010
		FOSSIL2	PROLOG	FOSSIL2	PROLOG	FOSSIL2
Intermediate 10%	0.16	No detectable change	No detectable change	No detectable change	No detectable change	No detectable change
Intermediate 70%	2.49	No detectable change	No detectable change	1.4%	No detectable change to 0.4%	1.6%
Subtitle C 10%	9.51	No detectable change	0.3% to 0.4%	4.2%	1.6% to 3.5%	6.3%
Subtitle C 70%	68.84	3.2%	6.9% to 7.8%	18.1%	19.1% to 32.4%	28.6%
Subtitle C-1 10%	4.73	No detectable change	No detectable change	1.4%	0.3% to 1.4%	3.2%
Subtitle C-1 70%	36.51	2.1%	3.7% to 4.3%	12.5%	10.7% to 18.5%	19.0%

Source: ERG estimates for extraction cost increase and for PROLOG impacts. Applied Energy Services of Arlington, Virginia, (Wood 1987) for FOSSIL2 results, based on specific runs of U.S. Department of Energy FOSSIL2 Model for alternative scenario cost increases. Department of Energy baseline crude oil price per barrel assumptions in FOSSIL2 were \$20.24 in 1990, \$33.44 in 2000, and \$52.85 in 2010.

Table VI-16 Effect of Domestic Production Decline on Selected Economic Parameters in the Year 2000

Waste management scenario	Projected decline in lower 48 production (%) <sup>a</sup>	Increase in petroleum imports (millions of barrels per day)	Increase in U.S. balance of trade deficit (\$ billions per year)	Increase in world oil price (dollars per barrel) <sup>a</sup>	Annual cost to consumers of the oil price increase (\$ billions per year)	Decrease in Federal leasing revenues (\$ millions per year)	Decrease in State tax revenues (\$ millions per year)
Intermediate 10%	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Intermediate 70%	1.4%	N.D.	\$0.2	\$0.06	\$0.4	\$19.1	\$71.0
Subtitle C 10%	4.2%	0.2	\$3.2	\$0.21	\$1.2	\$53.6	\$208.9
Subtitle C 70%	18.1%	1.1	\$17.5	\$1.08	\$6.4	\$279.8	\$903.2
Subtitle C-1 10%	1.4%	0.1	\$1.6	\$0.12	\$0.7	\$20.9	\$60.7
Subtitle C-1 70%	12.5%	0.7	\$11.3	\$0.76	\$4.5	\$176.2	\$616.1

N.D. - Not detectable using the FOSSIL2/WOIL modeling system.

<sup>a</sup> Revised baseline values for year 2000 in the FOSSIL2 modeling system include (1) lower 48 States crude oil production of 7.2 million barrels per day; (2) U.S. imports of 9.2 million barrels per day; and (3) world crude oil price of \$33.44 per barrel.

Source: Results based on U.S. Department of Energy's FOSSIL2/WOIL energy modeling system, with special model runs for individual waste management scenario production costs effects conducted by Applied Energy Services of Arlington, Virginia (Wood 1987). ERG estimates based on FOSSIL2 results.

A new equilibrium shows the following effects:

- A lower level of domestic supply (previously depicted in Table VI-15);
- A higher world oil price (see Table VI-16);
- A decrease in U.S. oil consumption caused by the higher world oil price; and
- An increase in U.S. imports to partially substitute for the decline in domestic supply (also shown in Table VI-16).

The first numerical column in Table VI-16 shows the decline in U.S. production associated with each waste management scenario. These projections, derived from simulations of the FOSSIL2/WOIL modeling system, were previously shown in Table VI-15. The second column in Table VI-16 provides FOSSIL2/WOIL projections of the increase in petroleum imports necessary to replace the lost domestic supplies. The projections range from "not detectable" to 1.1 million barrels per day, equal to 1.4 to 18.1 percent of current imports of approximately 6.1 million barrels per day.

The third column in Table VI-16 shows the increase in the U.S. balance of trade deficit resulting from the increase in imports and the increase in the world oil price. The increase in the U.S. balance of trade deficit ranges from \$0.2 to \$17.5 billion under the waste management scenarios. The projected increase in petroleum imports under the most restrictive regulatory scenarios could be a matter for some concern in terms of U.S. energy security perspectives, making the country somewhat more vulnerable to import disruptions and/or world oil price fluctuations. In the maximum case estimated (Subtitle C 70% Scenario), import dependence would increase from 56 percent of U.S. crude oil requirements in the base case to 64 percent in the year 2000.

The fourth column shows the crude petroleum price increase projected under each of the waste management scenarios by the FOSSIL2/WOIL modeling system. This increase ranges from \$0.06 to \$1.08 per barrel of oil (a 0.2 to 3 percent increase). This increase in oil price translates into an increase in costs to the consumer of \$0.4 to \$6.4 billion in the year 2000 (column five). These estimates are derived by multiplying FOSSIL2-projected U.S. crude oil consumption in the year 2000 by the projected price increase. The estimates assume that the price increase is fully passed through to the consumer with no additional downstream markups.

Federal leasing revenues will also decline under the waste management scenarios. These revenues consist of lease bonus payments (i.e., initial payments for the right to explore Federal lands) and royalties (i.e., payments to the Federal government based on the value of production on Federal lands). Both of these revenue sources will decline because of the production declines associated with the waste management scenarios. If the revenue sources are combined, there will be a reduction of \$19 to \$280 million in Federal revenues in the year 2000.

State governments generally charge a tax on crude oil production in the form of severance taxes, set as a percentage of the selling price. On a national basis, the tax rate currently averages approximately 6.7 percent. Applying this tax rate, the seventh column in Table VI-16 shows the projected decline in State tax revenues resulting from the waste management scenarios. These estimates range from about \$60 million to \$900 million per year.



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# CHAPTER VII

## CURRENT REGULATORY PROGRAMS

### INTRODUCTION

A variety of programs exist at the State and Federal levels to control the environmental impacts of waste management related to the oil and gas industry. This chapter provides a brief overview of the requirements of these programs. It also presents summary statistics on the implementation of these programs, contrasting the numbers of wells and other operations regulated by these programs with resources available to implement regulatory requirements.

State programs have been in effect for many years, and many have evolved significantly over the last decade. The material presented here provides only a general introduction to these complex programs and does not attempt to cover the details of State statutes and current State implementation policy. Additional material on State regulatory programs can be found in Appendix A. Federal programs are administered both by the Environmental Protection Agency and by the Bureau of Land Management within the U.S. Department of the Interior.

### STATE PROGRAMS

The tables on the following pages compare the principal functional requirements of the regulatory control programs in the principal oil- and gas-producing States that have been the focus of most of the analysis of this study. These States are Alaska, Arkansas, California, Colorado, Kansas, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Texas, West Virginia, and Wyoming.

Table VII-1 covers requirements for reserve pit design, construction, and operation; Table VII-2 covers reserve pit closure and waste removal. Table VII-3 presents requirements for produced water pit design and construction, while Table VII-4 compares requirements for the produced water surface discharge limits. Table VII-5 deals with produced water injection well construction; these requirements fall under the general Federal Underground Injection Control program, which is discussed separately below under Federal programs. Finally, Table VII-6 discusses requirements for well abandonment and plugging.

## FEDERAL PROGRAMS--EPA

Federal programs discussed in this section include the Underground Injection Control (UIC) program and the Effluent Limitations Guidelines program administered by the EPA.

### Underground Injection Control

The Underground Injection Control (UIC) program was established under Part C of the Safe Drinking Water Act (SDWA) to protect underground sources of drinking water (USDWs) from endangerment by subsurface emplacement of fluids through wells. Part C of the SDWA requires EPA to:

1. Identify the States for which UIC programs may be necessary--EPA listed all States and jurisdictions;
2. Promulgate regulations establishing minimum requirements for State programs which:
  - prohibit underground injection that has not been authorized by permit or by rule;
  - require applicants for permits to demonstrate that underground injection will not endanger USDWs;
  - include inspection, monitoring, record-keeping, and reporting requirements.

These minimum requirements are contained in 40 CFR Parts 144 and 146, and were promulgated in June 1980.

3. Prescribe by regulation a program applicable to the States, in cases where States cannot or will not assume primary enforcement responsibility. These direct implementation (DI) programs were codified in 40 CFR Part 147.

The regulations promulgated in 1980 set minimum requirements for 5 classes of wells including Class II wells--wells associated with oil and gas production and hydrocarbon storage. In December 1980, Congress amended the SDWA to allow States to demonstrate the effectiveness of their in-place regulatory programs for Class II wells, in lieu of demonstrating that they met the minimum requirements specified in the UIC regulations. In order to be deemed effective, State Class II programs had to meet the same statutory requirements as the other classes of wells, including prohibition of unauthorized injection and protection of underground sources of drinking water. (§1425 SDWA). Because of the large number of Class II wells, the regulations allow for authorization by rule for existing enhanced recovery wells (i.e., wells that were injecting at the time a State program was approved or prescribed by EPA). In DI States, these wells are subject to requirements specified in Part 147 for authorization by rule, which are very similar to requirements applicable to permitted wells, with some relief available from casing and cementing requirements as long as the wells do not endanger USDWs. In reviewing State programs where the intent was to "grandfather" existing wells as long as they met existing requirements, EPA satisfied itself that these requirements were sufficient to protect USDWs. In addition, all States adopted the minimum requirements of §146.08 for demonstrating mechanical integrity of the wells (ensuring that the well was not leaking or allowing fluid movement in the borehole), at least every 5 years. This requirement was deemed by EPA

to be absolutely necessary in order to prevent endangerment of USDWs. In addition, EPA and the States have been conducting file reviews of all wells whether grandfathered or subject to new authorization-by-rule requirements. File reviews are assessments of the technical issues that would normally be part of a permit decision, including mechanical integrity testing, construction, casing and cementing, operational history, and monitoring records. The intent of the file review is to ensure that injection wells not subject to permitting are technically adequate and will not endanger underground sources of drinking water.

Because of §1425 and the mandate applicable to Federal programs not to interfere with or impede underground injection related to oil and gas production, to avoid unnecessary disruption of State programs and to consider varying geologic, hydrologic, and historical conditions in different States, EPA has accepted more variability in this program than in many of its other regulatory programs. Now that the program has been in place for several years, the Agency is starting to look at the adequacy of the current requirements and may eventually require more specificity and less variation among States.

#### Effluent Limitations Guidelines

On October 30, 1976, the Interim Final BPT Effluent Limitations Guidelines for the Onshore Segment of the Oil and Gas Extraction Point Source Category were promulgated as 41 FR (44942). The rulemaking also proposed Best Available Technology Economically Achievable (BAT) and New Source Performance Standards.

On April 13, 1979, BPT Effluent Limitations Guidelines were promulgated for the Onshore Subcategory, Coastal Subcategory, and Agricultural and Wildlife Water Use Subcategory of the Oil and Gas Extraction Industry (44 FR 22069). Effluent limitations were reserved for the Stripper Subcategory because of insufficient technical data.

The 1979 BPT regulation established a zero discharge limitation for all wastes under the Onshore Subcategory. Zero discharge Agricultural and Wildlife Subcategory limitations were established, except for produced water, which has a 35-mg/L oil and grease limitation.

The American Petroleum Institute (API) challenged the 1979 regulation (including the BPT regulations for the Offshore Subcategory) (661 F.2D.340(1981)). The court remanded EPA's decision transferring 1,700 wells from the Coastal to the Onshore Subcategory (47 FR 31554). The court also directed EPA to consider special discharge limits for gas wells.

#### Summary of Major Regulatory Activity Related to Onshore Oil and Gas

October 13, 1976 - Interim Final BPT Effluent Limitations Guidelines and Proposed (and Reserved) BAT Effluent Limitations Guidelines and New Source Performance Standards for the Onshore Segment of the Oil and Gas Extraction Point Source Category

April 13, 1979 - Final Rules

- BPT Final Rules for the Onshore, Coastal, and Wildlife and Agricultural Water Use Subcategories
- Stripper Oil Subcategory reserved
- BAT and NSPS never promulgated



- July 21, 1982 - Response to American Petroleum Institute vs. EPA Court Decision
- Recategorization of 1,700 "onshore" wells to Coastal Subcategory
  - Suspension of regulations for Santa Maria Basin, California
  - Planned reexamination of marginal gas wells for separate regulations

#### Onshore Segment Subcategories

##### Onshore

- BPT Limitation
  - Zero discharge
- Defined: NO discharge of wastewater pollutants into navigable waters from ANY source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand).

##### Stripper (Oil Wells)<sup>1</sup>

- Category reserved
- Defined: TEN barrels per well per calendar day or less of crude oil.

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<sup>1</sup> This subcategory does not include marginal gas wells.

## Coastal

- BPT Limitations
  - No discharge of free oil (no sheen)
  - Oil and grease: 72 mg/L (daily)  
48 mg/L (average monthly)  
(produced waters)
- Defined: Any body of water landward of the territorial seas or any wetlands adjacent to such waters.

## Wildlife and Agriculture Use

- BPT Limitations
  - Oil and Grease: 35 mg/L (produced waters)
  - Zero Discharge: ANY waste pollutants
- Defined: That produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses west of the 98th meridian.

## FEDERAL PROGRAMS--BUREAU OF LAND MANAGEMENT

Federal programs under the Bureau of Land Management (BLM) within the U.S. Department of the Interior are discussed in this section.

### Introduction

Exploration, development, drilling, and production of onshore oil and gas on Federal and Indian lands are regulated separately from non-Federal lands. This separation of authority is significant for western States where oil and gas activity on Federal and Indian lands is a large proportion of statewide activity.

### Regulatory Agencies

The U.S. Department of the Interior exercises authority under 43 CFR 3160 for regulation of onshore oil and gas practices on Federal and Indian lands. The Department of the Interior administers its regulatory program through BLM offices in the producing States. These offices generally have procedures in place for coordination with State agencies on regulatory requirements. Where written agreements are not in place, BLM usually works cooperatively with the respective State agencies. Generally, where State requirements are more stringent than those of BLM, operators must comply with the State requirements. Where State requirements are less stringent, operators must meet the BLM requirements.

The Bureau works closely with the U.S. Forest Service for surface stipulations in Federal forests or Federal grasslands. This cooperative arrangement is specifically provided for in the Federal regulations.

## Rules and Regulations

BLM has authority over oil and gas activities on Federal lands. The authority includes leasing, bonding, royalty arrangements, construction and well spacing regulations, waste handling, most waste disposal, site reclamation, and site maintenance.

Historically, BLM has controlled oil and gas activities through Notices to Lessees (NTLs) and through the issuance of permits. The Bureau is working to revise all notices into Oil and Gas Orders, which will be Federally promulgated. To date, Oil and Gas Order No. 1 has been issued.

While the regulations, NTLs, and orders provide the general basis for regulation of oil and gas activities on Federal and Indian lands, there are variations in actual application of some of the requirements among BLM districts. In many cases, the variations are in response to specific geographical or geological characteristics of particular areas.

For example, in middle and southern Florida, the water table is near the surface. As a result, BLM requires the use of tanks instead of mud pits for oil and gas drilling activities on Federal lands in this area. In southeast New Mexico, there is simultaneous development of potash resources and oil and gas resources, and drilling and development requirements are imposed to accommodate the joint development activities. In general, more stringent controls of wastes and of disposal activities are required for oil and gas activities that could affect ground-water aquifers used for drinking water.

## Drilling

Before beginning to drill on Federal land, operators must receive a permit to drill from BLM. The permit application must include a narrative description of waste handling and waste disposal methods planned for the well. Any plans to line the reserve pit must be detailed.

The lease is required to be covered by a bond prior to beginning drilling of the well. But the bonds may be for multiple wells, on a lease basis, statewide basis, or nationwide basis. The current bond requirement for wells on a single lease is \$10,000. Statewide bonds are \$25,000, but bonds must be provided separately for wells on public land and wells on Federally acquired land. The requirement for a nationwide bond is \$150,000.

BLM considers reserve pits, and some other types of pits, as temporary. Except in special circumstances, reserve pits do not have to be lined. NTL-2B contains the following provisions for "Temporary Use of Surface Pits":

Unlined surface pits may be used for handling or storage of fluids used in drilling, re-drilling, reworking, deepening, or plugging of a well provided that such facilities are promptly and properly emptied and restored upon completion of the operations. Mud or other fluids contained in such pits shall not be disposed of by cutting the pit walls without the prior authorization of the authorized officer.

Unlined pits may be retained as emergency pits, if approved by the authorized officer, when a well goes into production.

Landspreading of drilling and reworking wastes by breaching pit walls is allowed when approved by the authorized officer.

## Production

Produced waters may be disposed of by underground injection, by disposal into lined pits, or "by other acceptable methods." An application to dispose of produced water must specify the proposed method and provide information that will justify the method selected. One application may be submitted for the use of one disposal method for produced water from wells and leases located in a single field, where the water is produced from the same formation or is of similar quality.

Disposal in Pits: A number of general requirements apply to disposal into permanent surface disposal pits, whether lined or unlined. The pits must:

1. Have adequate storage capacity to safely contain all produced water even in those months when evaporation rates are at a minimum;
2. Be constructed, maintained, and operated to prevent unauthorized surface discharges of water; unless surface discharge is authorized, no siphon, except between pits, will be permitted;
3. Be fenced to prevent livestock or wildlife entry to the pit, when required by an authorized officer;
4. Be kept reasonably free from surface accumulations of liquid hydrocarbons by use of approved skimmer pits, settling tanks, or other suitable equipment; and
5. Be located away from the established drainage patterns in the area and be constructed so as to prevent the entrance of surface water.

Approval of disposal of produced water into unlined pits will be considered only if one or more of the following applies:

- The water is of equal or better quality than potentially affected ground water or surface waters, or contains less than 5,000 ppm total dissolved solids (annual average) and no objectionable levels of other toxic constituents;

- A substantial proportion of the produced water is being used for beneficial purposes, such as irrigation or livestock or wildlife watering;
- The volume of water disposed of does not exceed a monthly average of 5 barrels/day/facility; and
- A National Pollutant Discharge Elimination System (NPDES) permit has been granted for the specific disposal method.

Operators using unlined pits are required to provide information regarding the sources and quantities of produced water, topographic map, evaporation rates, estimated soil percolation rates, and "depth and extent of all usable water aquifers in the area."

Unlined pits may be used for temporary containment of fluids in emergency circumstances as well as for disposal of produced water. The pit must be emptied and the fluids appropriately disposed of within 48 hours after the emergency.

Where disposal in lined pits is allowed, the linings of the pits must be impervious and must not deteriorate in the presence of hydrocarbons, acids, or alkalis. Leak detection is required for all lined produced water disposal pits. The recommended detection system is an "underlying gravel-filled sump and lateral system." Other systems and methods may be considered acceptable upon application and evaluation. The authorized officer must be given the opportunity to examine the leak detection system before installation of the pit liner.

When applying for approval of surface disposal into a lined pit, the operator must provide information including the lining material and leak detection method for the pit, the pit's size and location, its net evaporation rate, the method for disposal of precipitated solids, and an analysis of the produced water. The water analysis must include concentrations of chlorides, sulfates, and other (unspecified) constituents that could be toxic to animal, plant, or aquatic life.

Injection: Produced waters may be disposed of into the subsurface, either for enhanced recovery of hydrocarbon resources or for disposal. Since the establishment of EPA's underground injection control program for Class II injection wells, BLM no longer directly regulates the use of injection wells on Federal or Indian lands. Instead, it defers to either EPA or the State, where the State has received primacy for its program, for all issues related to ground-water or drinking water protection. Operators must obtain their underground injection permits from either EPA or the State.

BLM still retains responsibility for making determinations on injection wells with respect to lease status, protection of potential oil and gas production zones, and the adequacy of pressure-control and other safety systems. It also requires monthly reports on volumes of water injected.

#### Plugging/Abandonment

When a well is a dry hole, plugging must take place before removal of the drilling equipment. The mud pits may be allowed to dry before abandonment of the site. No abandonment procedures may be started without the approval of an authorized BLM representative. Final approval of abandonment requires the satisfactory completion of all surface reclamation work called for in the approved drilling permit.

Within 90 days after a producing well ceases production, the operator may request approval to temporarily abandon the well. Thereafter, reapproval for continuing status as temporarily abandoned may be required every 1 or 2 years. Exact requirements depend on the District Office and on such factors as whether there are other producing wells on the lease. The well may simply be defined as shut-in if equipment is left in place.



Plugging requirements for wells are determined by the BLM District Office. Typically, these will include such requirements as a 100-foot cement plug over the shoe of the surface casing (half above, half below), a 20- to 50-foot plug at the top of the hole, and plugs (usually 100 feet across) above and below all hydrocarbon or freshwater zones.

## IMPLEMENTATION OF STATE AND FEDERAL PROGRAMS

Table VII-7 presents preliminary summary statistics on the resources of State oil and gas regulatory programs for the 13 States for which State regulatory programs have been summarized in Tables VII-1 through VII-6. Topics covered include rates of gas and oil production, the number of gas and oil wells, the number of injection wells, the number of new wells, the responsible State agency involved, and the number of total field staff in enforcement positions.

Table VII-8 presents similar statistics covering activities of the Bureau of Land Management. Since offices in one State often have responsibilities for other States, each office is listed separately along with the related States with which it is involved. Statistics presented include the number of oil and gas producing leases, the number of nonproducing oil and gas leases, and the number of enforcement personnel available to oversee producing leases.

Table VII- 1 Reserve Pit Design, Construction and Operation

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/oversight
Alaska	The pits must be rendered impervious.	Whether reserve pit requires lining (and what kind of lining) depends on proximity to surface water and populations, whether the pit is above permafrost, and what kind of pit management strategy is used; visual monitoring required, and ground water monitoring usually required.	Fluid mgmt provision entails use of dewatering practices to keep to a minimum the hydrostatic head in a containment structure to reduce the potential for seepage and to prevent overflow during spring thaw.	Reserve pit "drilling wastes" defined as including "drilling muds, cuttings, hydrocarbons, brine, acid, sand, and emulsions or mixtures of fluids produced from and unique to the operation or maintenance of a well."	Individual permit for active and new pits.
Arkansas (revisions due in '88)	Oil & Gas Commission (OGC); no specific regulations governing construction or management of reserve pits. Dept. of Pollution Control & Ecology (DPCE) incorporates specific requirements in letters of authorization serving as informal permits, but regulatory basis and legal enforceability not supported by OGC.	OGC: No regulatory requirement. DPCE: 20-mil synthetic or 18-24 inch thick liner (per authorization letter).	1-ft freeboard (DPCE: 2-ft per authorization letter).	DPCE only; no high TDS completion fluids (per authorization letter).	OGC: No separate permit for reserve pit. DPCE: Terms of permitting for reserve pits incorporated in letter of authorization.
California	No degradation of ground-water quality; if waste is hazardous, detailed standards apply to the pits as "surface	Liners may or may not be required, depending on location and local regulations; in limited cases where fluids		Use of nonapproved additives and fluids renders the waste subject to regulation as a hazardous waste.	Regional Water Quality Control Boards (RWQCBs) have authority to permit, oversee management,

Table VII-1 (continued)

State	General statement of objective/purpose	Liners	Over-topping	Commingling provision	Permitting/oversight
California (continued)	impoundments"; if non-hazardous, the waste "shall be disposed of in such a manner as not to cause damage to life, health, property, fresh water aquifers or surface waters, or natural resources, or be a menace to public safety."	contain hazardous materials, double liners required			
Colorado	Prevent pollution (broadly defined) of State waters; prevent exceeding of stream standards.	Liners and leak detection systems generally reqd for pits with a capacity greater than 100 bbl/d and a TD5 content greater than 5,000 ppm; liners also reqd in designated areas overlying domestic water supplies.		No prohibition on commingling of drilling muds; and initial water production, but disposal of greater than 5 bbl/d produced water renders the reserve pit subject to regulations for pits receiving produced water; no wells drilled with oil-based muds.	Individual permit if pit receives more than 5 barrels fluid per day.
Kansas	Specific delineation of areas requiring liners (proposed)	No general requirement; liners may be required in geologically or hydrologically sensitive areas (e.g., over sandy soils); Commission may require observation trenches, holes, or monitoring wells.	1-ft freeboard (proposed regs).		General permits for pits operating for less than 1 year (extensions granted); individual permits granted unless denied within 10 days of application (proposed regs).

Table VII-1 (continued)

State	General statement of objective/purpose	Liners	Overlapping	Commingling provision	Permitting/oversight
Louisiana	Prevent contamination of aquifers, including USDWs, and protect surface water.	Liners not required for onsite reserve pits; liners (10 <sup>-7</sup> cm/sec) reqd for offsite commercial facilities.  Liners required when drilling with salt water-based drilling fluids; or when drilling through salt or brine-containing formations; in other areas, exceptions may be granted, but rarely are requested; liners must be 20 mil virgin PVC or its equivalent.	2-ft freeboard, protection of surface water by levees, walls, and drainage ditches.	No produced water or waste oil at onsite facilities	More stringent reqts. (including financial respons.) for commercial facilities.
Michigan				No salt cuttings as solids, oil, refuse, completion or test fluids.	Individual permit bond, and environmental assessment reqd.
New Mexico	Prevent contamination of surface and subsurface water.	Liners not required for onsite reserve pits; in the Northwest, liners may be required for commercial facilities.			Permits are reqd for centralized facilities with some exceptions.
Ohio	Prevent escape of produced water; prevent contamination of land, surface water, and ground water.	No requirement for liners, except where required on a site-specific basis in hydrogeologically sensitive areas.			

Table VII-1 (continued)

States	General statement of objective/purpose	Liners	Overtopping	Comingling provision	Permitting/oversight
Oklahoma	Prevent pollution of surface and subsurface water; commercial pits must be sealed with an impervious material.	No liner requirement for reserve pits for wells using freshwater drilling muds; 30-mil liners (or metal tanks) reqd for pits containing "deleterious fluids other than freshwater drilling muds;" 12-inch, $10^{-7}$ cm/sec soil liner for commercial pits; commercial pits must be at least 25 feet above highest aquifer; site-specific reqt for coml pits containing deleterious fluids.	18-inch freeboard and run-on controls; 36 inches for commercial pits.	More stringent reqts (i.e., liners) for fluids other than water-based muds; provide an incentive to manage these wastes separately.	Permit not reqd for on-site pits; notification reqd for emergency and burn pits.
Texas	May not cause or allow pollution of surface or subsurface water.	Liners not required.		Use of reserve pits and mud circulation pits is restricted to drilling fluids, drill cuttings, sands, slits, wash water, drill stem test fluids, and blowout preventer test fluids.	Reserve pits and mud circulation pits are authorized by rule without permits; individual permit reqd for coml facilities, drilling fluid storage pits (other than mud circulation pits), and drilling fluid disposal pits (other than reserve pits).

Table VII-3 (continued)

States	General statement of objective/purpose	Liners	Overlapping	Controlling provision	Permitting oversight
W. Virginia	Prevent seepage, leakage, or overflow and maintain pit integrity.	Liners not reqd, except where soil is not suitable to prevent seepage or leakage.	Adequate freetboard	No produced water, unused fracturing fluid or acid, compressor oil, refuse, diesel, kero- sene, halogenated pheno- l, etc.	General permit, offsite discharge of fluids re- quire an individual permit.
Wyoming	Prevent pollution of streams and underground water and unreasonable damage to the land.	Liners not reqd except where the potential for communication between the pit contents and surface water or shallow ground water is high.		No chemicals that re- duce the pit's fluid seal.	Individual permit reqd except for workover and completion pits contain- ing oil and/or water; more stringent design reqts for commercial pits.

Table VII-2 Reserve Pit Closure/Waste Removal

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Alaska	Must be operated with a fluid management plan and must be closed within 1 year after final disposal of drilling wastes in pit; or must be designed for 2 years' disposal and closed in that time period; numerous performance reqts added.	General permit for discharge of fluids to tundra; prior written approval reqd; specs and effluent monitoring for metals and conventional pollutants; only pits eligible are those that have received no drilling wastes since previous summer (last freeze-thaw cycle), to allow precipitation of contaminants.	Individual permit; compliance point is edge of the road for same specs as for land application (except pH); no requirement for freeze-thaw cycle.	See land application; specs same as AK WQS (except TDS) pending study to determine effect on wildlife.	General permit for N. Slope; prior written approval reqd; discharge must occur below the permafrost into a zone containing greater than 3,000 ppm TDS.
Arkansas (revisions due in '88)	OGC: No specific regulatory requirements. DPCE: within 60 days of rig's removal, reclaim to grade and reseed; fluids must be consigned to state-permitted disposal service (per authorization letter).	DPCE only: waste analysis and landowner's consent reqd for land application (per authorization letter).		° Prohibited.	DPCE: prior approval reqd (per authorization letter).
California	When drilling operations cease, remove either (1) all wastes or (2) all free liquids and hazardous residuals.	Offsite disposal reqts depend on whether waste is "hazardous" (double liners), "designated" (single liner) or non-hazardous.		Permit reqd from RWQCB; disposal may not cause damage to surface water.	
Colorado	For dry and abandoned wells, within 6 months of a well's closure, decant the fluids, backfill and reclaim.	Dewatered sediment may be tilled into the ground.		Permits for discharge may be issued if effluent meets stream's classification standard.	

Table VII-2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Kansas	As soon as practical, evaporate or dewater and backfill; 365 days, or sooner if specifically required by Commission (proposed).	Landfarming is prohibited; in-situ disposal may be prohibited in sensitive areas.	If approved by Kansas Department of Health and Environment.		Prohibited.
Louisiana	Within 6 months of completion of drilling or workover activities, fluids must be analyzed for pH, O&G, metals and salinity, and then removed; exemption for wells less than 5,000 ft deep if native mud used.	Onsite land treatment or trenching of fluids and land treatment, burial or solidification of nonfluids allowed provided specs are met (including pH, electrical conductivity, and certain metals).		Permits issued for discharge of wastewater from treated drilling site reserve pits, so long as limitations for oil and grease, TSS, metals, chlorides, pH are met. Dilution allowed to meet chloride limits.	Surface casing must be at least 200 ft below the lowest USDW.
Michigan	At closure, all free liquids must be removed and the residue encapsulated onsite or disposed of offsite.	In-situ encapsulation requires a 10-mil PVC cap 4 ft below grade; offsite disposal must be in a lined landfill with leachate collection and ground-water monitoring	Prohibited.	Prohibited.	Well must have production casing and injected fluid must be isolated below freshwater horizons; exception granted if, among other things, pressure gradient is less than 0.7 psi.
New Mexico		Pits are evaporated and residue generally buried onsite.		Prohibited.	



Table VII-2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Ohio	Within 5 months of the commencement of drilling, backfill and remove concrete bases and drilling equipment, within 9 months, grade and revegetate area not reqd for production.	Drilling fluids may be disposed of by land application; pit solids may be buried onsite, except where history of ground-water problems		Permit reqd.	Standard well treatment fluids can be injected; same reqts as for annular produced water disposal; permit generally reqd
Oklahoma	Within 12 months of drilling operation's cessation, dewater and leave; 6-month extension for good cause; only 60 days allowed for circulating and fracture pits.	Landfarming of water-based muds is allowed; permit reqd; siting and rate application reqts, waste analysis, revegetation within 120 days		Prohibited.	Onsite injection allowed, approval reqd; surface casing must be set at least 200 ft below treatable water; limits on pressure so that vertical fractures will not extend to base of treatable water.
Texas	Within 30 days to 1 year from when drilling ceases (depending on the fluid's Cl content) dewater, backfill, and compact.	Landfarming prohibited for water-based drilling fluids having greater than 3,000 mg/L Cl and oil-based wastes, onsite burial prohibited for oil-based drilling fluids (but burial of solids obtained while using oil-based drilling fluid allowed)		Minor permit required for discharge of fluid fraction from treated reserve pits; prior notif. and 24-hour bioassay test reqd; discharge may not violate TX WQS or haz. metals limits; specs include O&G (15 mg/L), Cl (1,000 mg/L coastal, 500 mg/L in-land); TSS (50 mg/L), COD (200 mg/L), TDS (3000 mg/L)	One-time annular injection allowed; "minor permit" required; limits on surface injection pressure; casing set such that usable quality water protected to depth recommended by TWL.

Table VII-2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Artificial injection
W. Virginia	Within 6 months from when drilling ceases.	Cuttings may be buried onsite; after physical treatment, fluids meeting specs can be applied to the land; specs include oil (no visible sheen on land) and Cl (25,000 mg/L), monitoring reqd for other parameters.			
Wyoming	Within 1 year of use, remove liquids and reclaim pit; reclamation bond released after pit closure inspected and approved.	Permit reqd for land application; discharge must meet water quality limits, including O&G (2,000 or 20,000 lb/acre, depending on whether soil incorporated), Cl (1,500 mg/L).	Permit reqd for road application; location and application reqts imposed through DEQ memorandum.	Prohibited, except where DEQ determines discharge will not cause sig. envir damage or contaminate public water supplies; application must include complete analysis, volume, location, and name of receiving stream.	One-time injection allowed under some conditions as in UIC permit.

Table VII-3 Produced Water Pit Design and Construction

State	General statement of objective/purpose	Liners	Exemptions	Permitting/oversight
Alaska	Produced water is a "drilling waste" and is subject to the same reqts as in Table VII-1.			
Arkansas (revisions due in '88)	No discharge into any water of the State (including ground water).	Pits must be lined or underlaid by tight soil; pits prohibited over porous soil; (DPCE authorization letter requires tanks).		Individual permit; application reqd within 30 days of producing waste.
California	Nondegradation of State waters; pits not permitted in natural drainage channels or where they may be in communication with freshwater-bearing aquifers.	Liners reqd where necessary to comply with the State's nondegradation policy; specific standards for construction/operation may be established by RWQCBs.		Subject to permitting authority of Regional WQCB.
Colorado	Prevent pollution (broadly defined) of State waters; prevent exceeding of stream standards.	Same as for reserve pits (for pits receiving more than 5 bbl/d 90% of the pits are lined; 2/3 clay, 1/3 synthetic)	Exemptions from liner requirement for pits overlying impermeable materials or receiving water with less than 5,000 ppm TDS.	Individual permit.
Kansas	Consideration of protection of soil and water resources from pollution.	Strict liner and seal requirements in conjunction with hydrogeologic investigation.		No permits issued for unlined pits.
Louisiana		All pits must be lined such that the hydraulic conductivity is less than $10^{-7}$ cm/sec.	Pits in certain coastal areas, provided they are part of a treatment train for oil and grease removal.	

State	General statement of objective/purpose	Liners	Exemptions	Permitting/oversight
Michigan	Brine cannot be run to earthen reservoirs or ponds.			
New Mexico		In the southeast, 30-mil liners with leak detection are reqd; in the northwest, liners are reqd over specified vulnerable aquifers.	Small-volume pits and pits in specified areas that are already saline and in areas with out fresh water.	If liner required, individual permit after hearing.
Ohio	Pits must be liquid tight; waste cannot be stored for more than 180 days; pits may not be used for ultimate disposal.			Produced water disposal plan must be submitted.
Oklahoma	Pits must be sealed with an impervious material; in addition, offsite pits must contain fluids with less than 3,500 ppm Cl.	12-inch, $10^{-7}$ cm/sec soil liner for coml pits; site-specific liner reqd if coml pit contains deleterious fluids		Individual permits required.
Texas	Permit for unlined pit denied unless operator conclusively shows pit will not pollute agricultural land, surface or subsurface water; emergency pits generally exempted.	Generally, all pits other than emergency pits require liners unless (1) there is no surface or subsurface water in the area, or (2) the pit is underlain by a naturally occurring impervious barrier; liners required for emergency pits in sensitive areas.		Individual permit.
W. Virginia	Same as for reserve pits.	Same as for reserve pits.		Same as for reserve pits.
Wyoming		Liners not reqd except where the potential for communication between the pit contents and surface water or shallow ground water is high.		Individual permit reqd if pit receives more than 5 bbl/day produced water; area-wide permits also granted; individual permits and more stringent terms for commercial pits.

Table VII-4 Produced Water Surface Discharge Limits

State	Onshore	Coastal/tidal	Beneficial use	Permitting/oversight
Alaska				Produced water is subject to the discharge reqts for reserve pit fluids in Table VII-1.
Arkansas	Prohibited.	Not applicable.		
California	In some cases, produced waters ultimately disposed of in sumps are allowed to first be discharged into canals or ephemeral streams that carry the salt water to the sumps.	Policy for enclosed bays and estuaries prohibits discharge of materials of petroleum origin in sufficient quantities to be visible or in violation of waste discharge reqts; Ocean Plan sets limits for O&G, arsenic, total chromium, etc.	Discharge allowed to canals, ditches, and ephemeral streams before reuse; specs issued by one RWQCB include O&G (35 mg/L) and C1 (200 mg/L).	Permit reqd from RWQCB for beneficial use.
Colorado	Discharge must not cause pollution (broadly defined) of any waters of the state; must not cause exceeding of stream standards.	N/A	Specs for wildlife and agricultural use include O&G (10 mg/L) and TDS (5,000 mg/L, 30-day average).	Permit reqd from Water Quality Control Division of Department of Health.
Kansas	Prohibited.	N/A		Road application requires approval by Dept. of Health and Environment.
Louisiana	Discharges allowed into lower distributaries of Mississippi and Atchafalaya Rivers; discharges into waters of the State require a permit after 11/20/86; facility deemed in compliance except where an investigation or a complaint has been filed.	Discharge allowed if treated to remove residual O&G.		Individual permits for surface discharges required after 11/20/86.

Table VII-2 (continued)

State	Onshore	Coastal/Tidal	Beneficial use	Permitting Oversight
Michigan	Prohibited.	Prohibited.	Specs for dust control, 3-yr study to determine if practice should be continued.	
New Mexico	Prohibited except in emergencies or for construction, application reqd.	N/A	Use as drinking water for cattle and in construction, no contaminant levels specified.	State approval for cattle watering and construction reqd.
Ohio	Discharge must not cause pollution of any waters of the State.	N/A	Reqts for road spreading include a 12-ft buffer zone to prevent damage to water bodies.	Road or land spreading must be authorized by city/municipal resolution, RPDES permit reqd for onshore discharges.
Oklahoma	Prohibited.	N/A		Individual permit.
Texas	Prohibited, unless fresh.	Discharges allowed, but skimming required to prevent oil in tidal waters; testing for oil every 30-40 days.		
W. Virginia	No discharge of salt water or other water unfit for domestic livestock into waters of State.	N/A	Road application allowed pending study.	RPDES permit reqd for onshore discharges, general permit for stripper wells expected mid-1987.
Wyoming	Specs include O&G (10 mg/l) and Cl (2,000 mg/L); no discharge of toxic substances at conc. toxic to humans, animals, or aquatic life.	N/A		RPDES permit reqd for surface discharges.

Table VII-5 Produced Water Injection Well Construction

State	Casing	MIT pressure and duration	MIT frequency	Abandoned wells
Alaska	Safe and appropriate casing, cemented to protect oil, gas, and fresh water; detailed casing specs.	30 min at 1,500 psi or 0.25 psi/ft times vertical depth of casing shoe, whichever is greater; max. pressure decline 10%.	Before operation; thereafter monthly reporting of casing-tubing annulus pressure.	1/4-mile area of review.
Arkansas	Well must be cased and cemented so as not to damage oil, gas, or fresh water.	Determined by AOGC on a case-by-case basis.	Before operation; thereafter every 5 years.	1/2-mile area of review.
California	Safe and appropriate casing; cementing specs.	From hydrostatic to the pressure reqd to fracture the injection zone or the proposed injection pressure, whichever occurs first; step rate test may be waived.	Within 3 months after injection commences and annually thereafter, after any anomalous rate or pressure change, or as requested by DOG.	1/4-mile fixed radius in combination with radial flow equation and documented geological features are used to define area of review.
Colorado	Safe and adequate casing or tubing to prevent leakage, and cemented so as not to damage oil, gas, or fresh water.	15 min at 300 psi or the minimum injection pressure, whichever is greater; max. variance 10%.	Before operation, thereafter every 5 years; exceptions for wells monitoring annulus pressure monthly.	1/4-mile area of review; notice to surface and working interest owners within 1 mile.
Kansas	Well must be cased and cemented to prevent damage to hydrocarbon sources or fresh and usable water.	For old wells, 100 psi; for new wells, 100 psi or the authorized pressure, whichever is greater; alternative tests allowed; 30-minute test.	Before operation; thereafter every 5 years	1/4-mile area of review.
Louisiana	Casing must be set through the deepest USDW and cemented to the surface.	For new wells, 30 min at 300 psi, or max. allowable pressure, whichever is greater; for converted wells, the lesser of 1,000 psi or max. allowable pressure, but no lower than 300 psi; max. variance of 5 psi.	Before operation; thereafter every 5 years.	1/4-mile area of review.

Table VII-5 (continued)

State	Casing	MII pressure and duration	MII frequency	Abandoned wells
Michigan	Casing and seal to prevent the loss of produced water into an unapproved formation.	30 min at 300 psi, 3/4 allowable bleedoff.	As scheduled by RA (Federal, administered).	State program to plug abandoned wells.
New Mexico	Casing or tubing to prevent leakage and fluid movement from the injection zone.	15-30 min at 250-300 psi; max. variance 10%.	Before operation, thereafter every 5 years; special test can be reqd more often; annulus monitoring required monthly.	State program to plug abandoned wells; 2 1/2-mile area of review, variance allowing no less than 1/4 mile; corrective action reqd to prevent migration through conduits.
Ohio	In addition to use of injection wells, annular disposal of produced water is allowed; max annular disposal 5-10 bbl/d; use only force of gravity; systems must be airtight.			
	Casing must be set at least 50 ft below the deepest USDW and must be cemented to the surface.	15 min at 300 psi, or max. allowable pressure, whichever is greater; max. decline 5%; alternative tests allowed.	Before operation; thereafter every 5 years.	1/4- to 1/2-mile area of review, depending on volume injected; well plugging fund.
Oklahoma	Casing must be set at least 90 ft below the surface or 50 ft below treatable water, whichever is lower, and must be cemented to the surface.	Same as Louisiana, except maximum bleedoff of 10%.	Before operation; thereafter every 5 years; exception for wells monitoring pressure monthly and reporting annually.	1/2-mile area of review; well plugging fund.
Texas	Surface casing cemented to surface; tubing and cemented casing string to isolate injection zone.	Test at 500 psig, or max. allowable pressure, whichever is less, but at least 200 psig; max. decline of 10%; once pressure stabilizes, 30 minutes with no variation.	Before injection, after workover, and thereafter every 5 years (exception for wells monitoring annulus pressure monthly and rpt'g annually, or for other viable alternative test).	1/4-mile area of review; notice to surface owners and offset operators; well plugging fund (main source: \$100 drilling permit fee).



Table VII-5 (continued)

State	Casing	MII pressure and duration	MII frequency	Abandoned wells
W. Virginia		20 min at 1.5 to 2 times the injection pressure; max. variance 5%.	Every 5 years.	
Wyoming	Surface casing must be set below freshwater sources; casing cemented to the surface.	Same as Louisiana.	Before injection, thereafter every 5 years.	Notice to landowner, and operators within 1/2 mile, 1/4-mile area of review.

Table VII-6 Well Abandonment/Plugging

States	Plugging deadline	Plugging oversight
Alaska	1 year following end of operator's activity within the field; if well not completed, must be abandoned or suspended before removal of drilling equipment; bridge plugs reqd for suspended wells.	Plugging method must be approved before beginning work; indemnity bond released after approval of well abandonment.
Arkansas	If not completed, must be abandoned/plugged before drilling equip. is released from the drilling operation; no time limit for temporary abandonment of properly cased well.	Plugging permit; onsite supervision by AOGC official; bond or other evidence of financial responsibility reqd, and released only after plugging/abandonment completed.
California	6 months after drilling activity ceases or 2 years after drilling equipment is removed; unless temp. abandonment of properly cased well.	Indemnity bond released after proper abandonment or completion is ensured.
Colorado	Generally, 6 months after production ceases; extensions require semi-annual status report.	Plugging method must be approved; COGC must have opportunity to witness; blanket or individual bond reqd.
Kansas	90 days after operations cease; where temporary abandonment, annual extensions require notice and status reports.	Plugging plan reqd before beginning work; report reqd after completion.
Louisiana	Within 90 days of notice in "Inactive Well Report" unless a plan is submitted describing the well's future use.	
Michigan	Within 60 days after cessation of drilling activities; within 1 year after cessation of production (with extensions, if sufficient reason to retain well).	Plugging method must be approved.

Table VII-8 (continued)

State	Plugging deadline	Plugging oversight
New Mexico	Generally, 6 months; extensions granted for up to 2 yr at a time	Well plugging plan must be approved; plugging bond released after inspection and Director approval.
Ore.	Immediately upon abandonment of a dry hole, without undue delay after prod ceases; extensions provided for 6 months.	Before plugging, approval reqd; after plugging, report reqd including identity of witnesses; liability insurance reqd; surety bond forfeited if noncompliance with regs.
Oklahoma	Where prod. casing has been run, 1 year after cessation of drilling (numerous exceptions); less time where no, or only surface, casing run; special rules for temporary abandonment.	Plugging must be supervised by an authorized rep. of the Conservation Division; plugging report reqd; proof of financial ability to comply with plugging reqt.
Texas	Within 90 days after drilling or operations cease, except where cessation occurred in '65 or '67 (1 year); extensions at Director's discretion (if no pollution hazard) with plugging bond or letter of credit or plan to use for enhanced recovery.	Before plugging, notification and approval reqd; after plugging, report reqd; operator must be present during plugging.
W. Virginia	Prompt plugging reqd if dry holes and wells not in use for 12 mo; extensions for good cause.	Plugging bond and notif. to the Director and nearby coal operators reqd.
Wyoming	Approval from the State reqd if well is "temporarily abandoned" for more than 1 year.	Before plugging, approval reqd; after plugging, report reqd; well plugging bond released after the State inspection.

Table VII-7 State Enforcement Matrix

State	Gas Production	Oil Production	Gas wells	Oil wells	Injection wells	New wells	Agency	Personnel*
Alaska	316,000 Mmcf 1986	681,309,821 bbl 1986	104	1,191	472 Class II 425 EOR 47 Disposal	100 new onshore wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Conservation	8 enforcement positions 8 enforcement positions
Arkansas	194,483 Mmcf 1985	19,715,691 bbl 1985	2,492	9,490	1,211 Class II 239 EOR 972 Disposal	1,055 new wells completed in 1985	Arkansas Oil and Gas Commission Department of Pollution Control and Ecology	7 enforcement positions 2 enforcement positions
California	493,000 Mmcf 1985	423,900,000 bbl 1985	1,566	55,079	11,066 Class II 10,047 EOR 1,019 Disposal	3,413 new wells completed in 1985	Conservation Dept., Division of Oil and Gas Department of Fish and Game	31 enforcement positions
Kansas	466,600 Mmcf 1984	75,723,000 bbl 1984	12,680	57,633	14,902 Class II 9,366 EOR 5,536 Disposal	6,025 new wells completed in 1985	Kansas Corporation Commission	30 enforcement positions
Louisiana	5,867,000 Mmcf 1984	449,545,000 bbl 1984	14,436	25,823	4,436 Class II 1,283 EOR 3,153 Disposal	5,447 new onshore wells completed 1985	Department of Environmental Quality Office of Conservation - Injection and Mining	32 enforcement positions 36 enforcement positions
New Mexico	893,300 Mmcf 1985	78,500,000 bbl 1985	18,308	21,986	3,871 Class II 3,508 EOR 363 Disposal	1,747 new wells completed in 1985	Energy and Minerals Department, Oil Conservation Division	10 enforcement positions
Ohio	182,200 Mmcf 1985	14,987,592 bbl 1985	31,343	29,210	3,956 Class II 127 EOR 3,829 Disposal	6,297 new wells completed in 1985	Ohio Department of Natural Resources, Division of Oil and Gas	66 enforcement positions
Oklahoma	1,996,000 Mmcf 1984	153,250,000 bbl 1984	23,647	99,030	22,803 Class II 14,901 EOR 7,902 Disposal	9,176 new wells completed in 1985	Oklahoma Corporation Commission	52 enforcement positions
Pennsylvania	166,000 Mmcf 1984	4,825,000 bbl 1984	24,050	20,739	6,183 Class II 4,315 EOR 1,868 Disposal	4,627 new wells completed in 1985	Department of Environmental Resources, Bureau of Oil and Gas Management	34 enforcement positions
Texas	5,805,000 Mmcf 1985	830,000,000 bbl 1985	68,811	210,000	53,141 Class II 45,223 EOR 7,918 Disposal	25,721 new wells completed in 1985	Texas Railroad Commission	120 enforcement positions
West Virginia	142,500 Mmcf 1986	3,600,000 bbl 1986	32,500	15,895	761 Class II 687 EOR 74 Disposal	1,839 new wells completed in 1985	West Virginia Department of Energy	15 enforcement positions
Wyoming	597,896 Mmcf 1985	130,984,917 bbl 1985	2,220	12,218	5,880 Class II 5,257 EOR 623 Disposal	1,735 new wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Quality	7 enforcement positions 4.5 enforcement positions

\*Only field staff are included in total enforcement positions.

Table VII-8 BLM Enforcement Matrix\*

Office location	Other States for which office is responsible	Producing oil and gas leases	Nonproducing oil and gas leases**	Personnel (for producing leases only)
Alaska		43	8,443	1 enforcement position
California		305	1,383	7 enforcement positions
Colorado		3,973	4,463	10 enforcement positions
Idaho		0	471	0 enforcement positions
Mississippi		116	1,519	3 enforcement positions
	Alabama	12	567	
	Arkansas	161	1,099	
	Florida	1	0	
	Kentucky	13	65	
	Louisiana	121	487	
	Virginia	1	523	
	Total	425	4,260	
Montana		958	4,721	12 enforcement positions
	North Dakota	456	1,991	
	South Dakota	98	572	
	Total	1,512	7,284	
Nevada		43	3,045	1 enforcement position
New Mexico		5,725	9,306	43 enforcement positions
	Arizona	10	386	
	Kansas	150	227	
	Oklahoma	2,767	2,754	
	Texas	61	279	
	Total	8,713	12,952	
Oregon		0	1,513	0
Utah		1,654	7,222	10 enforcement positions
Wisconsin		0	0	1 enforcement position
	Maryland	2	11	
	Michigan	28	603	
	Missouri	1	6	
	Ohio	33	69	
	Pennsylvania	6	1	
	West Virginia	46	54	
	Total	116	844	
Wyoming		5,037	28,044	27 enforcement positions
	Nebraska	42	582	
	Total	5,079	28,626	
	Total	22,037	102,251	115 enforcement positions

\* Oil and gas inspectors working in the field as of March 30, 1987. At that time there were eight vacancies nationwide.

\*\* Includes leases that have never been drilled, have been drilled and abandoned, or are producing wells that have been temporarily shut down.

## REFERENCES

43 CFR 3100 (entire group).

U.S. Bureau of Land Management. (Not dated.) Federal Onshore Oil and Gas Leasing and Operating Regulations.

U.S. Bureau of Land Management. NTL-2B.

U.S. Department of the Interior - Geological Survey Division. (Not dated.) Notice to Lessees and Operators of Federal and Indian Oil and Gas Leases (NTL-2B).

Personal communication with Mr. Steve Spector, September 23, 1986.

# CHAPTER VIII

## CONCLUSIONS

From the analysis conducted for this report, it is possible to draw a number of general conclusions concerning the management of oil and gas wastes. These conclusions are presented below.

Available waste management practices vary in their environmental performance.

Based on its review of current and alternative waste management practices, EPA concludes that the environmental performance of existing waste management practices and technologies varies significantly. The reliability of waste management practices will depend largely on the environmental setting. However, some methods will generally be less reliable than others because of more direct routes of potential exposure to contaminants, lower maintenance and operational requirements, inferiority of design, or other factors. Dependence on less reliable methods can in certain vulnerable locations increase the potential for environmental damage related to malfunctions and improper maintenance. Examples of technologies or practices that are less reliable in locations vulnerable to environmental damage include:

- Annular disposal of produced water (see damage case OH 38, page IV-16);
- Landspreading or roadspreading of reserve pit contents (see damage case WV 13, page IV-24);
- Use of produced water storage pits (see damage case AR 10, page IV-36); and

- Surface discharges of drilling waste and produced water to sensitive systems such as estuaries or ephemeral streams (see damage cases TX 55, page IV-49; TX 31, page IV-50; TX 29, page IV-51; WY 07, page IV-60; and CA 21, page IV-68).

Any program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use.

Current technologies and practices for the management of wastes from oil and gas operations are well established, and their environmental performance is generally understood. Improvements in State regulatory requirements over the past several years are tending to increase use of more desirable technologies and practices and reduce reliance on others. Examples include increased use of closed systems and underground injection and reduced reliance on produced water storage and disposal pits.

Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices. Examples include incineration and other thermal treatment processes for drilling fluids; conservation, recycling, reuse, and other waste minimization techniques; and wet air oxidation and other proven technologies that have not yet been applied to oil and gas operations.

Because of Alaska's unique and sensitive tundra environment, there has been special concern about the environmental performance of waste management practices on the North Slope. Although there are limited and preliminary data that indicate some environmental impacts may occur, these data and EPA's initial analysis do not indicate the need to curtail current or future oil exploration, development, and production operations on the North Slope. However, there is a need for more environmental data



on the performance of existing technology to provide assurance that future operations can proceed with minimal possible adverse impacts on this sensitive and unique environment. The State of Alaska has recently enacted new regulations which will provide additional data on these practices.

EPA is concerned in particular about the environmental desirability of two waste management practices used in Alaska: discharge of reserve pit supernatant onto tundra and road application of reserve pit contents as a dust suppressant. Available data suggest that applicable discharge limits have sometimes been exceeded. This, coupled with preliminary biological data on wildlife impacts and tundra and surface water impairment, suggests the need for further examination of these two practices with respect to current and future operations. The new regulations recently enacted by the State of Alaska should significantly reduce the potential for tundra and wildlife impacts.

Increased segregation of waste may help improve management of oil and gas wastes.

The scope of the exemption, as interpreted by EPA in Chapter II of this report, excludes certain relatively low-volume but possibly high-toxicity wastes, such as unused pipe dope, motor oil, and similar materials. Because some such wastes could be hazardous and could be segregated from the large-volume wastes, it may be appropriate to require that they be segregated and that some of these low-volume wastes be managed in accordance with hazardous waste regulations. While the Agency recognizes that small amounts of these materials may necessarily become mixed with exempt wastes through normal operations, it seeks to avoid any deliberate and unnecessary use of reserve pits as a disposal mechanism. Segregation of these wastes from high-volume exempt wastes appears to be desirable and should be encouraged where practical.

Although this issue is not explicitly covered in Chapter VII, EPA is aware that some States do require segregation of certain of these low-volume wastes. EPA does not have adequate data on which to judge whether these State requirements are adequate in coverage, are enforceable, are environmentally effective, or could be extended to general operations across the country. The Agency concludes that further study of this issue is desirable.

**Stripper operations constitute a special subcategory of the oil and gas industry.**

Strippers cumulatively contribute approximately 14 percent of total domestic oil production. As such, they represent an economically important component of the U.S. petroleum industry. Two aspects of the stripper industry raise issues of consequence to this study.

First, generation of production wastes by strippers is more significant than their total petroleum production would indicate. Some stripper wells yield more than 100 barrels of produced water for each barrel of oil, far higher on a percentage production basis than a typical new well, which may produce little or no water for each barrel of oil.

Second, stripper operations as a rule are highly sensitive to small fluctuations in market prices and cannot easily absorb additional costs for waste management.

Because of these two factors--inherently high waste-production rates coupled with economic vulnerability--EPA concludes that stripper operations constitute a special subcategory of the oil and gas industry that should be considered independently when developing recommendations for possible improvements in the management of oil and gas wastes. In

the event that additional Federal regulatory action is contemplated, such special consideration could indicate the need for separate regulatory actions specifically tailored to stripper operations.

Documented damage cases and quantitative modeling results indicate that, when managed in accordance with State and Federal requirements, exempted oil and gas wastes rarely pose significant threats to human health and the environment.

Generalized modeling of human health risks from current waste management practices suggests that risks from properly managed operations are low. The damage cases researched in the course of this project, however, indicate that exempt wastes from oil and gas exploration, development, and production can endanger human health and cause environmental damage when managed in violation of existing State requirements.

#### Damage Cases

In a large portion of the cases developed for this study, the types of mismanagement that lead to such damages are illegal under current State regulations although a few were legal under State programs at the time when the damage originally occurred. Evidence suggests that violations of regulations do lead to damages. It is not possible to determine from available data how frequently violations occur or whether violations would be less frequent if new Federal regulations were imposed.

Documented damages suggest that all major types of wastes and waste management practices have been associated to some degree with endangerment of human health and damage to the environment. The principal types of wastes responsible for the damage cases include general reserve pit wastes (primarily drilling fluids and drill cuttings,

but also miscellaneous wastes such as pipe dope, rigwash, diesel fuel, and crude oil); fracturing fluids; production chemicals; waste crude oil; produced water; and a variety of miscellaneous wastes associated with exploration, development, or production. The principal types of damage sometimes caused by these wastes include contamination of drinking-water aquifers and foods above levels considered safe for consumption, chemical contamination of livestock, reduction of property values, damage to native vegetation, destruction of wetlands, and endangerment of wildlife and impairment of wildlife habitat.

### Risk Modeling

The results of the risk modeling suggest that of the hundreds of chemical constituents detected in both reserve pits and produced fluids, only a few from either source appear to be of concern to human health and the environment via ground-water and surface water pathways. The principal constituents of potential concern, based on an analysis of their toxicological data, their frequency of occurrence, and their mobility in ground water, include arsenic, benzene, sodium, chloride, boron, cadmium, chromium, and mobile salts. All of these constituents were included in the quantitative risk modeling; however, boron, cadmium, and chromium did not produce risks or resource damages under the conditions modeled.

For these constituents of potential concern, the quantitative risk modeling indicates that risks to human health and the environment are very small to negligible when wastes are properly managed. However, although the risk modeling employed several conservative assumptions, it was based on a relatively small sample of sites and was limited in scope to the management of drilling waste in reserve pits, the underground injection of produced water, and the surface water discharge of produced water from stripper wells. Also, the risk analysis did not consider

migration of produced water contaminants through fractures or unplugged or improperly plugged and abandoned wells. Nevertheless, the relatively low risks calculated by the risk modeling effort suggest that complete adherence to existing State requirements would preclude most types of damages.

Damages may occur in some instances even where wastes are managed in accordance with currently applicable State and Federal requirements.

There appear to be some instances in which endangerment of human health and damage to the environment may occur even where operations are in compliance with currently applicable State and Federal requirements.

#### Damage Cases

Some documented damage cases illustrate the potential for human health endangerment or environmental damage from such legal practices as discharge to ephemeral streams, surface water discharges in estuaries in the Gulf Coast region, road application of reserve pit contents and discharge to tundra in the Arctic, annular disposal of produced waters, and landspreading of reserve pit contents.

#### Risk Modeling

For the constituents of potential concern, the quantitative evaluation did indicate some situations (less than 5 percent of those studied) with carcinogenic risks to maximally exposed individuals higher than 1 in 10,000 ( $1 \times 10^{-4}$ ) and sodium levels in excess of interim limits for public drinking water supplies. Although these higher risks resulted only under conservative modeling assumptions, including high (90th percentile) concentration levels for the toxic constituents, they do indicate potential for health or environmental impairment even under the

general assumption of compliance with standard waste management procedures and applicable State and Federal requirements. Quantitative risk modeling indicates that there is an extremely wide variation (six or more orders of magnitude) in health and environmental damage potential among different sites and locations, depending on waste volumes, wide differences in measured toxic constituent concentrations, management practices, local hydrogeological conditions, and distances to exposure points.

Unplugged and improperly plugged abandoned wells can pose significant environmental problems.

Documentation assembled for the damage cases and contacts with State officials indicate that ground-water damages associated with unplugged and improperly plugged abandoned wells are a significant concern. Abandoned disposal wells may leak disposed wastes back to the surface or to usable ground water. Abandoned production wells may leak native brine, potentially leading to contamination of usable subsurface strata or surface waters.

Many older wells, drilled and abandoned prior to current improved requirements on well closure, have never been properly plugged. Many States have adequate regulations currently in place; however, even under some States' current regulations, wells are abandoned every year without being properly plugged.

Occasionally companies may file for bankruptcy prior to implementing correct plugging procedures and neglect to plug wells. Even when wells are correctly plugged, they may eventually leak in some circumstances in the presence of corrosive produced waters. The potential for environmental damage occurs wherever a well can act as a conduit between usable ground-water supplies and strata containing water with high

chloride levels. This may occur when the high-chloride strata are pressurized naturally or are pressurized artificially by disposal or enhanced recovery operations, thereby allowing the chloride-rich waters to migrate easily into usable ground water.

Discharges of drilling muds and produced waters to surface waters have caused locally significant environmental damage where discharges are not in compliance with State and Federal statutes and regulations or where NPDES permits have not been issued.

Damage cases indicate that surface water discharges of wastes from exploration, development, and production operations have caused damage or danger to lakes, ephemeral streams, estuaries, and sensitive environments when such discharges are not carried out properly under applicable Federal and State programs and regulations. This is particularly an issue in areas where operations have not yet received permits under the Federal NPDES program, particularly along the Gulf Coast, where permit applications have been received but permits have not yet been issued, and on the Alaskan North Slope, where no NPDES permits have been issued.

For the Nation as a whole, Regulation of all oil and gas field wastes under unmodified Subtitle C of RCRA would have a substantial impact on the U.S. economy.

The most costly hypothetical hazardous waste management program evaluated by EPA could reduce total domestic oil production by as much as 18 percent by the year 2000. Because of attendant world price increases, this would result in an annual direct cost passed on to consumers of over \$6 billion per year. This scenario assumes that 70 percent of all drilling and production wastes would be subject to the current requirements of Subtitle C of RCRA. If only 10 percent of drilling wastes and produced waters were found to be hazardous, Subtitle C regulation would result in a decline of 4 percent in U.S. production and

a \$1.2 billion cost increase to consumers, compared with baseline costs, in the year 2000.

EPA also examined the cost of a Subtitle C scenario in which produced waters injected for the purpose of enhanced oil recovery would be exempt from Subtitle C requirements. This scenario yielded production declines ranging from about 1.4 to 12 percent and costs passed on to consumers ranging from \$0.7 to \$4.5 billion per year, depending on whether 10 percent or 70 percent of the wastes (excluding produced waters injected for enhanced oil recovery) were regulated as hazardous wastes.

These Subtitle C estimates do not, however, factor in all of the Hazardous and Solid Waste Act Amendments relating to Subtitle C land disposal restrictions and corrective action requirements currently under regulatory development. If these two requirements were to apply to oil and gas field wastes, the impacts of Subtitle C regulation would be substantially increased.

The Agency also evaluated compliance costs and economic impacts for an intermediate regulatory scenario in which moderately toxic drilling wastes and produced waters would be subject to special RCRA requirements less stringent than those of Subtitle C. Under this scenario, affected drilling wastes would be managed in pits with synthetic liners, caps, and ground-water monitoring programs and regulated produced waters would continue to be injected into Class II wells (with no surface discharges allowed for produced waters exceeding prescribed constituent concentration limits). This scenario would result in a domestic production decline, and a cost passed on to consumers in the year 2000, of 1.4 percent and \$400 million per year, respectively, if 70 percent of



the wastes were regulated. If only 10 percent of the wastes were subject to regulation, this intermediate scenario would result in a production decline of less than 1 percent and an increased cost to consumers of under \$100 million per year.

The economic impact analysis also estimates affects on U.S. foreign trade and State tax revenues. By the year 2000, based on U.S. Department of Energy models, the EPA cost results projected an increase in national petroleum imports ranging from less than 100 thousand to 1.1 million barrels per day and a corresponding increase in the U.S. balance of payments deficit ranging from less than \$100 thousand to \$18 billion annually, depending on differences in regulatory scenarios evaluated. Because of the decline in domestic production, aggregated State tax revenues would be depressed by an annual amount ranging from a few million to almost a billion dollars, depending on regulatory assumptions.

Regulation of all exempt wastes under full, unmodified RCRA Subtitle C appears unnecessary and impractical at this time.

There appears to be no need for the imposition of full, unmodified RCRA Subtitle C regulation of hazardous waste for all high-volume exempt oil and gas wastes. Based on knowledge of the size and diversity of the industry, such regulations could be logistically difficult to enforce and could pose a substantial financial burden on the oil and gas industry, particularly on small producers and stripper operations. Nevertheless, elements of the Subtitle C regulatory program may be appropriate in select circumstances. Reasons for the above tentative conclusion are described below.

The Agency considers imposition of full, unmodified Subtitle C regulations for all oil and gas exploration, development, and production wastes to be unnecessary because of factors such as the following.

- Damages and risks posed by oil and gas operations appear to be linked, in the majority of cases, to violations of existing State and Federal regulations. This suggests that implementation and enforcement of existing authorities are critical to proper management of these wastes. Significant additional environmental protection could be achieved through a program to enhance compliance with existing requirements.
- State programs exist to regulate the management of oil and gas wastes. Although improvements may be needed in some areas of design, implementation, or enforcement of these programs, EPA believes that these deficiencies are correctable.
- Existing Federal programs to control underground injection and surface water discharges provide sufficient legal authority to handle most problems posed by oil and gas wastes within their purview.

The Agency considers the imposition of full Subtitle C regulations for all oil and gas exploration, development, and production wastes to be impractical because of factors such as the following:

- EPA estimates that the economic impacts of imposition of full Subtitle C regulations (excluding the corrective action and land disposal restriction requirements), as they would apply without modification, would significantly reduce U.S. oil and gas production, possibly by as much as 22 percent.
- If reserve pits were considered to be hazardous waste management facilities, requiring permitting as Subtitle C land disposal facilities, the administrative procedures and lengthy application processes necessary to issue these permits would have a drastic impact on development and production.
- Adding oil and gas operations to the universe of hazardous waste generators would potentially add hundreds of thousands of sites to the universe of hazardous waste generators, with many thousands of units being added and subtracted annually.
- Manifesting of all drilling fluids and produced waters offsite to RCRA Subtitle C disposal facilities would pose difficult logistical and administrative problems, especially for stripper operations, because of the large number of wells now in operation.

States have adopted variable approaches to waste management.

State regulations governing proper management of Federally exempt oil and gas wastes vary to some extent to accommodate important regional differences in geological and climatic conditions, but these regional environmental variations do not fully explain significant variations in the content, specificity, and coverage of State regulations. For example, State well-plugging requirements for abandoned production wells range from a requirement to plug within 6 months of shutdown of operations to no time limit on plugging prior to abandonment.

Implementation of existing State and Federal requirements is a central issue in formulating recommendations in response to Section 8002(m).

A preliminary review of State and Federal programs indicates that most States have adequate regulations to control the management of oil and gas wastes. Generally, these State programs are improving. Alaska, for example, has just promulgated new regulations. It would be desirable, however, to enhance the implementation of, and compliance with, certain waste management requirements.

Regulations exist in most States to prohibit the use of improper waste management practices that have been shown by the damage cases to lead to environmental damages and endangerment of human health. Nevertheless, the extent to which these regulations are implemented and enforced must be one of the key factors in forming recommendations to Congress on appropriate Federal and non-Federal actions.

## CHAPTER IX

### RECOMMENDATIONS

*Following public hearings on this report, EPA will draw more specific conclusions and make final recommendations to Congress regarding whether there is a need for new Federal regulations or other actions. These recommendations will be made to Congress and the public within 6 months of the publication of this report.*

Use of Subtitle D and other Federal and State authorities should be explored as a means for implementing any necessary additional controls on oil and gas wastes.

EPA has concluded that imposition of full, unmodified RCRA Subtitle C regulation of hazardous waste for all exempt oil and gas wastes may be neither desirable nor feasible. The Agency believes, however, that further review of the current and potential additional future use of other Federal and State authorities (such as Subtitle D authority under RCRA and authorities under the Clean Water Act and the Safe Drinking Water Act) is desirable. These authorities could be appropriate for improved management of both exempt and nonexempt, high-volume or low-volume oil and gas wastes.

EPA may consider undertaking cooperative efforts with States to review and improve the design, implementation, and enforcement of existing State and Federal programs to manage oil and gas wastes.

EPA has concluded that most States have adequate regulations to control most impacts associated with the management of oil and gas wastes, but it would be desirable to enhance the implementation of, and compliance with, existing waste management requirements. EPA has also

concluded that variations among States in the design and implementation of regulatory programs warrant review to identify successful measures in some States that might be attractive to other States. For example, EPA may want to explore whether changes in State regulatory reporting requirements would make enforcement easier or more effective. EPA therefore recommends additional work, in cooperation with the States, to explore these issues and to develop improvements in the design, implementation, and enforcement of State programs.

During this review, EPA and the States should also explore nonregulatory approaches to support current programs. These might include development of training standards, inspector training and certification programs, or technical assistance efforts. They might also involve development of interstate commissions or other organizational approaches to address waste management issues common to operations in major geological regions (such as the Gulf Coast, Appalachia, or the Southwest). Such commissions might serve as a forum for discussion of regional waste management efforts and provide a focus for development and delivery of nonregulatory programs.

The industry should explore the potential use of waste minimization, recycling, waste treatment, innovative technologies, and materials substitution as long-term improvements in the management of oil and gas wastes.

Although in the near term it appears that no new technologies are available for making significant technical improvements in the management of exempt wastes from oil and gas operations, over the long term various innovative technologies and practices may emerge. The industry should explore the use of innovative approaches, which might include conservation and waste minimization techniques for reducing generation of drilling fluid wastes, use of incineration or other treatment technologies, and substitution of less toxic compounds wherever possible in oil and gas operations generally.