IV. WASTE RELEASE PROFILE

This section provides estimates and reported quantities of wastes released from oil and gas extraction industries. Unlike facilities covered by SIC codes 20-39 (manufacturing facilities), oil and gas extraction facilities are not required by the Emergency Planning and Community Right-to-Know Act to report to the Toxic Release Inventory (TRI). Because TRI reporting is not required for the oil and gas extraction industry, other sources of waste release data have been identified for this profile. EPA is considering expanding TRI reporting requirements in the future which may affect industries that are currently not required to report to TRI, such as oil and gas extraction.

Much of the published data on wastes generated at oil and gas extraction facilities is specific to the various oil producing regions of the United States, including onshore and offshore sites. In 1996, EPA developed effluent limitation guidelines for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. Much of the information presented below was collected as supporting technical information for the guidelines. Additional data reflecting the releases of onshore wells were provided by the Pennsylvania Department of Environmental Protection.

IV.A. Available Data on Produced Water

Produced water is the largest volume waste generated in oil and gas extraction operations. In 1985, the American Petroleum Institute (API) estimated that 20.8 billion barrels of produced water were generated per year by the U.S. onshore oil and gas production industry (Souders, 1998). API conducted an updated survey of the industry in 1995. Based on preliminary results, API estimates current produced water volumes at over 15 billion barrels annually (API, 1997). The decline can be attributed primarily to a 32 percent decrease in oil production over the decade. While natural gas production has risen, natural gas wells produce much less water than do oil wells.

The concentration of contaminants in produced water varies from region to region and depends on the depth of the production zone and the age of the well, among other factors. Since most contaminants found in produced water are naturally occurring, they will vary based on what is present in the subsurface at a particular location. Three tables are presented below that indicate both the relative concentrations of pollutants and the variation that can occur among samples from different locations and product streams. Table 5 presents the results of analyses performed on produced water from **-XX-** Venango County, Pennsylvania. Table 7 presents data from natural gas wells in the Devonian formation of Pennsylvania.

Table 5: Produced Water Effluent Concentrations – Gulf of Mexico (Coastal Waters)

Pollutant	Settling Effluent	Improved Gas Flotation Effluent
	Concentrations (Micrograms/L)	
Oil and Grease	26,600	23,500
Total Suspended Solids (TSS)	141,000	30,000
Priority Organic Pollutants		
2,4-Dimethylphenol	148	148
Benzene	5,200	1,226
Ethylbenzene	110	62.18
Naphthalene	184	92.02
Phenol	723	536
Toluene	4,310	827.80
Priority Metal Pollutants		
Cadmium	31.50	14.47
Chromium	180.00	180.00
Copper	236.00	236.00
Lead	726.00	124.86
Nickel	151.00	151.00
Silver	359.00	359.00
Zinc	462.00	133.85
Other Non-Conventional Pollutants		
Aluminum	1,410	49.93
Ammonia	41,900	41,900
Barium	52,800	35,561
Benzoic acid	5,360	5,360
Boron	22,800	16,473
Calcium	2,490,000	2,490,000
Chlorides	57,400,000	57,400,000
Cobalt	117	117
Hexanoic acid	1,110	1,110
2-Hexanone	34.50	34.50
Iron	17,000	3,146
Magnesium	601,000	601,000
Manganese	1,680	74.16
2-Methylnapthalene	78	77.70
Molybdenum	121	121
n-Decane	152	152
n-Dodecane	288	288
n-Eicosane	78.80	78.80
n-Hexadecane	316	316
n-Octadecane	78.80	78.80
n-Tetradecane	119	119
o-Cresol	152	152
p-Cresol	164	164
Strontium	287,000	287,000
Sulfur	12,200	12,200
Tin	430	430
Titanium	43.80	4.48
m-Xylene	147	147
o + p-Xylene	110	110
Vanadium	135	135
Yttrium	35.30	35.30
Lead 210	5.49e-07	5.49e-07
Radium 226	1.91e-04	1.91e-04
Radium 228	9.77e-07	9.77e-07

Source: EPA Office of Water, *Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*, October 1996, Table VIII-7.

Table 6: Oil Well Brine (Produced Water) from Primary Recovery Operations – Venango County, Pennsylvania

Parameter	Number of Samples	Average	Minimum	Maximum	No. Samples < reporting limit
pH	28	6.4	5.2	7.4	
Osmotic pressure (milliosmoles)	18	1,445	340	2,740	2>2,000
Specific conductance (umhos/cm)	28	73,426	14,980	128,900	
Sulfates (mg/L)	13	96	1	584	10
Surfactants (mg/L)	22	1.1	0.1	2.5	2
Total Alkalinity (mg/L)	19	104	5.8	251	
Total dissolved solids (mg/L)	27	58,839	14,210	135,506	
Total suspended solids (mg/L)	19	130	20	614	
Oil & grease (mg/L)	16	18.6	2.74	78	3
Ammonia (mg/L)	17	9.3	2.22	17	
Hardness (mg/L)	27	13,075	2,199	30,720	
Calcium (mg/L)	26	3,602	10.8	6,750	
Bromide (mg/L)	17	283	57	538	
Chlorides (mg/L)	29	33,356	6,350	63,700	
Magnesium (mg/L)	28	670	87	1820	
Sodium (mg/L)	27	13,417	6	26,700	
Aluminum (µg/L)	15	730	156	1730	1
Arsenic (µg/L)	15	273	24	992	9
Barium (mg/L)	29	55.7	0.04	670	
Beryllium (µg/L)	11	11.4	0.2	95	11
Cadmium (µg/L)	5	36	0.3	150	19
Copper (µg/L)	16	78	15	264	9
Iron (mg/L)	27	34	3.97	140	
Lead (µg/L)	4	288	13.9	910	19
Manganese (µg/L)	27	1,294	175	7,500	
Nickel (µg/L)	9	150	26	790	16
Silver (µg/L)	8	2,676	0.59	21,100	12
Zinc (µg/L)	11	93	14	310	5
Lithium (µg/L)	22	1,418	273	3,660	1
Phenols (µg/L)	16	454	28	875	
Benzene (µg/L)	12	1,907	79	3,236	
Toluene (µg/L)	10	1,885	540	3,214	
Ethylbenzene (µg/L)	7	107	55	174	2
Xylene (µg/L)	11	1,057	200	2,117	

Source: Pennsylvania DEP, *Draft Oil Brine Characteristics Report*, 1999.

Table 7: Gas Well Brine (Produced Water) Characteristics – Devonian Formation of Pennsylvania

Parameter	Range	Number of Samples
pH	3.1 - 6.47	16
Specific Conductance (umhos/cm)	136,000 - 586,000	12
Pollutants (mg/L)		
Alkalinity	0 - 285	13
Bromide	150 - 1149	5
Chloride	81,500 - 167,448	22
Sulfate	<1.0 - 47	13
Surfactants	0.08 - 1200	13
Total dissolved solids	139,000 - 360,000	15
Total suspended solids	8 - 5484	5
Aluminum	<0.50 - 83	19
Arsenic	<0.005 - 1.51	5
Barium	9.65 - 1740	28
Cadmium	<0.02 - 1.21	19
Calcium	9400 - 51,300	19
Copper	<0.02 - 5.0	14
Iron	39.0 - 680	21
Lead	<0.20 - 10.2	18
Lithium	18.6 - 235	18
Magnesium	1300 - 3900	18
Manganese	3.59 - 65	21
Nickel	<0.08 - 9.2	18
Potassium	149 - 3870	16
Silver	0.047 - 7.0	4
Sodium	37,500 - 120,000	21
Zinc	<0.02 - 5.0	20

Source: Pennsylvania DEP, 1999.

IV.B. Available Data on Drilling Waste for the Oil and Gas Extraction Industry

According to API, 361 million barrels of drilling waste were produced in 1985. Due to a reduction in the number of wells drilled, for 1995 API preliminary findings indicate an estimated 146 million barrels of drilling waste (API, 1997). Drilling fluids (muds and rock cuttings) are the largest sources of drilling wastes. For offshore Gulf of Mexico, EPA estimates from 1993 assumed that 7,861 barrels of drilling fluids and 2,681 barrels of cuttings are discharged overboard per exploratory well, and 5,808 barrels of drilling fluids and 1,628 barrels of cuttings are discharged per development well (USEPA, 1993b). The different volumes are based on the average depths for the two types of wells. These volumes exclude the volumes of any drilling wastes not discharged offshore but transported to shore for disposal. Historically, on average, about 12 percent of the mud and 2 percent of the cuttings fail permit limits (USEPA, 1993b) and thus cannot be discharged. Table 8 below summarizes some of the characteristics of drilling waste in Cook Inlet, Alaska as reported in the *Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*. Table 9 presents the characteristics of drilling fluids used in the drilling of gas wells into the Devonian formation of Pennsylvania.

Table 8: Cook Inlet Drilling Waste Characteristics

Waste Characteristics	Value
Percent of cuttings in waste drilling fluid	19%
Average density of dry cuttings	980 pounds per barrel
Average density of waste drilling fluid	420 pounds per barrel
Percent of dry solids in waste drilling fluid, by volume	11%
Average density of dry solids in waste drilling fluids	1,025 pounds per barrel
Drilling Fluid Pollutant Concentration Data	
Conventionals	**mg/kg drilling fluid**
Total Oil	142
Total Suspended Solids (TSS)	269,042
Priority Metals	
Cadmium	1.1
Mercury	0.1
Antimony	5.7
Arsenic	7.1
Beryllium	0.7
Chromium	240
Copper	18.7
Lead	35.1
Nickel	13.5
Selenium	1.1
Silver	0.7
Thallium	1.2
Zinc	200.5
Priority Organics	
Naphthalene	0.008
Fluorene	0.134
Phenanthrene	0.020
Non-Conventional Metals	
Aluminum	9,069.9
Barium	120,000
Iron	15,344.3
Tin	14.6
Titanium	87.5
Non-Conventional Organics	
Alkylated benzenes (a)	5.004
Alkylated naphthalenes (b)	0.082
Alkylated fluorenes (b)	0.290
Alkylated phenanthrenes (b)	0.034
Total byphenyls (b)	0.324
Total dibenzothiophenes	0.001

Source: EPA Office of Water, 1996, Table VII-4.

Table 9: Drilling Fluids Characteristics – Devonian Gas Wells

Parameter	Average	Range	# Samples Above Detection Limits	# Samples Below Detection Limits
pH	9.57	3.1 - 12.2	61	
Osmotic pressure (mosm)	76	4.3 - 629	32	
Specific Conductance (umhos/cm)	4,788	383 - 38,600	62	
Pollutants (mg/L)				
Oil & grease	11.9	2.3 - 38.8	20	2
Alkalinity	276	18 - 1,594	60	0
Bromide	10.2	2 - 56.1	30	4
Chloride	1,547	12 - 14,700	62	0
Phenols	0.288	0.025 - 0.137	19	3
Sulfate	144	6 - 785	46	0
Surfactants	25	1.5 - 200	23	13
Total dissolved solids	3,399	386 - 24,882	61	0
Total suspended solids	87	2 - 395	34	0
Aluminum	4.601	0.170 - 16.9	17	16
Arsenic	0.032	0.00082 - 0.117	21	13
Barium	2.5	0.078 - 37.7	37	13
Calcium	290	8.7 - 1,900	60	0
Copper	0.049	0.012 - 0.268	12	22
Iron	145	0.08 - 3,970	41	4
Lead	0.785	0.07 - 3.46	5	29
Lithium	0.46	0.037 - 2.04	8	12
Magnesium	59	0.12 - 1,700	61	1
Manganese	2.284	0.01 - 46.6	40	20
Nickel	0.945	0.025 - 2.4	7	27
Silver	0.035	0.035	1	7
Sodium	777	53.7 - 5,800	59	0
Zinc	0.502	0.014 - 1.55	14	20

Source: Pennsylvania DEP, 1999.

IV.C. Available Data on Miscellaneous and Minor Wastes (Associated Wastes)

Associated wastes are a relatively small but significant category of waste from the oil and gas extraction industry. The term "associated wastes" encompasses a wide range of small volume waste streams essential to oil and gas extraction. Because of their nature, these waste streams are the most likely to contain constituents of concern. Preliminary data from a 1995 survey estimate that 22 million barrels of associated wastes are generated annually (API, 1997). Four particular associated waste streams are discussed below.

IV.C.1. Workover, Treatment, and Completion Fluids

Well maintenance, including workover, treatment, and completion, requires the use of fluids similar to drilling fluid and is the largest miscellaneous source of waste. These fluids may contain a range of chemicals (depending on the maintenance activity undertaken) and naturally occurring materials (i.e., trace metals). Because of the presence of these constituents, the wastes require proper disposal. Onshore, most of these wastes are disposed of through Class II injection wells. Offshore, they may be discharged if they meet the standards in applicable NPDES permits. Otherwise, they are barged to shore and typically disposed of in an injection well. Table 10 presents the relative amounts of liquid and solid wastes from well maintenance operations. Table 11 contains the range and average pollutant concentrations from workover, treatment and completion fluid samples collected from wells in Texas, New Mexico, and Oklahoma.

Table 10: Typical Volumes from Well Treatment, Workover, and Completion Operations

Operation	Type of Material	Estimated Waste Volume (barrels)
Completion and Workover	Completion/Workover Fluids	200 to 1000
	Formation Sand	1 to 50
	Filtration Solids	10 to 50
	Excess Cement	<10
	Casing Fragments	<1
Well Treatment	Neutralized Spent Acids	10 to 500
	Completion/Workover Fluids	10 to 200

Source: EPA Office of Water, 1996, Table IX-2.

Table 11: Pollutant Concentrations in Treatment, Workover, and Completion Fluids

Pollutant Parameter	Pollutant Concentration (Micrograms/L)	
	Range	Average
Conventionals		
Oil and Grease	15,000 - 722,000	231,688
Total Suspended Solids	65,500 - 1,620,000	520,375
Priority Pollutant Organics		
Benzene	477 - 2,204	1,341
Ethylbenzene	154 - 2,144	1,149
Methyl Chloride (Chloromethane)	0 - 57	29
Toluene	298 - 1,484	891
Fluorene	0 - 123	62
Naphthalene	0 - 1,050	525
Phenanthrene	0 - 128	64
Phenol	255 - 271	263
Priority Pollutant Metals		
Antimony	0 - 148	29.60
Arsenic	0 - 693	166
Beryllium	0 - 25.1	8.64
Cadmium	7.6 - 82.3	26.08
Chromium	48 - 1,320	616.82
Copper	0 - 1,780	277.20
Lead	0 - 6,880	1,376
Nickel	0 - 467	115.52
Selenium	0 - 139	42.94
Silver	0 - 8	1.60
Thallium	0 - 67.3	13.46
Zinc	0 - 1330	362.94
Other Non-Conventionals		
Aluminum	0 - 13,100	6,468.40
Barium	66.5 - 3,360	498.10
Boron	4,840 - 45,200	15,042
Calcium	1,070,000 - 28,000,000	10,284,000
Cobalt	0 - 40.9	8.18
Cyanide	0 - 52	52
Iron	7,190 - 906,000	384,412
Manganese	187 - 18,800	5,146
Magnesium	10,400 - 13,500,000	5,052,280
Molybdenum	0 - 167	63
Sodium	7,170,000 - 45,200,000	18,886,000
Strontium	21,100 - 343,000	142,720
Sulfur	72,600 - 646,000	245,300
Tin	0 - 135	27
Titanium	0 - 283	74.58
Vanadium	0 - 4,850	1,156
Yttrium	0 - 131	41.92
Acetone	908 - 13,508	7,205
Methyl Ethyl Ketone (2-Butanone)	0 - 115	58
m-Xylene	335 - 3,235	1,785
o+p-Xylene	161 - 1,619	890
4-Methyl-2-Pentanone	198 - 5,862	3,028
Dibenzofuran	136 - 138	137
Dibenzothiophene	0 - 222	111
n-Decane	0 - 550	275
n-Docosane	237 - 1,304	771
n-Dodecane	0 - 1,152	576
n-Eicosane	0 - 451	226
n-Hexacosane	173 - 789	481
n-Hexadecane	0 - 808	404
n-Tetradecane	513 - 1,961	1,237
p-Cymene	0 - 144	72
Pentamethylbenzene	0 - 108	54
1-Methylfluorene	0 - 163	82
2-Methylnaphthalene	0 - 1,634	817

Source: EPA Office of Water, 1996, Table IX-7.

IV.C.2. Minor Wastes

Smaller waste streams of concern for the oil and gas extraction industry that are discussed below are drainage from drilling and production sites, solids brought to the surface with oil and gas (produced sand, also referred to as tank bottoms), and domestic and sanitary wastes at coastal and offshore sites.

Deck Drainage

Drainage from the production site, or *deck drainage*, is a concern particularly in areas with high precipitation. When water from rainfall or from equipment cleaning comes in contact with oil-coated surfaces, the water becomes contaminated and must be treated and disposed of. The fluids can contain oil from leaking equipment, wastes from cleaning operations, and spilled chemicals from treatment processes. Some locations will collect deck drainage, treat it separately in a skim tank, and discharge it, while others might combine the water with produced water and dispose of the fluids together. In the coastal areas of the Gulf of Mexico, the average facility generates approximately 12,000 barrels of deck drainage each year, but this figure would be significantly lower for facilities in drier climates (EPA, 1996).

Produced Sand

Produced sand consists of the accumulated formation sands and other particles generated during production as well as the slurried particles used in hydraulic fracturing. The waste stream also includes sludges produced from chemical flocculation procedures during produced water treatment. Produced sand typically contains crude oil. The amount will vary based on the handling and separation processes used, but can comprise as much as 19 percent by volume (EPA, 1996). Table 12 presents an analysis of samples of basic sediment taken from pits containing produced water in Pennsylvania. Like for produced water, it should be noted that concentrations will vary for different locations, particularly with respect to Naturally Occurring Radioactive Material (NORM).

Table 12: Pollutant Concentrations in Produced Water Pit Sediments in Pennsylvania				
Material	**Range (mg/L)**	**Average (mg/L)**	**# Samples Above Detection Limits**	**# Samples Below Detection Limits**
Oil and Grease (mg/kg)	640 - 540,000	68,056	49	0
Arsenic	<0.01 - 0.031		19	32
Barium	0.07 - 19.1	1.8	51	0
Cadmium	<0.05		0	51
Chromium	<0.05		0	51
Lead	<0.1 - 0.27		4	47
Mercury	<0.001		0	51
Selenium	<0.01 - 0.016		8	43
Silver	<0.05		0	51
Benzene	0.0006 - .25		25	21
Toluene	0.001 - 0.27		25	21
Ethylbenzene	0.0013 - 0.049		17	29
Naphthalene	0.001 - 0.076		5	41
Xylene	.0011 - 1.78		34	12
Naturally-Occurring Radioactive Materials				
Natural Uranium (µg/kg)	873.87-2,945.97	1,658.86	9	0
^{226}Radium (pCi/kg)	6.57 - 1,344.88	593.8196	23	0
^{228}Radium (pCi/kg)	13.8 - 1639.11	770.3883	23	0
^{54}Manganese (pCi/kg)	0		0	23
^{59}Iron (pCi/kg)	0		0	23
^{58}Cobalt+^{60}Cobalt (pCi/kg)	0		0	23
^{65}Zinc (pCi/kg)	0		0	23
^{95}Zirconium (pCi/kg)	0		0	23
^{95}Niobium (pCi/kg)	0		0	23
^{131}Iodine (pCi/kg)	0		0	23
^{137}Cesium (pCi/kg)	0 - 46	17.15789	19	4
^{140}Barium (pCi/kg)	0		0	23
^{140}Lanthanum (pCi/kg)	0		0	23
Thorium (total) (pCi/kg)	860 - 4,868	2,908.826	23	0
Source: PA DEP, *Characterization and Disposal Options for Oilfield Wastes in Pennsylvania*, 1994.				

Domestic and Sanitary Wastes

Domestic and sanitary wastes are issues at coastal and offshore sites. Domestic wastes are water from sinks, showers, laundry, and food preparation areas. Domestic waste also includes solid materials such as paper and cardboard which must be disposed of properly. Because domestic waste does not contain fecal coliform bacteria, most NPDES permits allow untreated discharge so long as floating solids are not produced. Sanitary wastes are generated from toilets, and must be either treated or stored for disposal on land. Most offshore facilities treat the wastes through a combination of chlorination and biological digesters or physical maceration, and discharge the waste at the site. Offshore facilities discharge an average of approximately 2,050 barrels of domestic/sanitary waste per facility per year (EPA, 1996).

IV.D. Other Data Sources

The Aerometric Retrieval System (AIRS) is an air pollution data delivery system managed by the Technical Support Division in EPA's Office of Air Quality Planning and Standards (OAQPS), located in Research Triangle Park, North Carolina. The AIRS is a national repository of data related to air pollution monitoring and control. The AIRS contains a wide range of information related to stationary sources of air pollution, including the emissions of a number of air pollutants which may be of concern within a particular industry. Table 13 summarizes annual releases (from the industries for which Sector Notebook Profiles have been prepared) of carbon monoxide (CO), nitrogen dioxide (NO_2), particulate matter of 10 microns or less (PM10), particulate matter, all sizes reported in lieu of PM10 (PT), sulfur dioxide (SO_2), and volatile organic compounds (VOCs).

Table 13: Air Pollutant Releases by Industry Sector (tons/year)

Industry Sector	CO	NO_2	PM10	PT	SO_2	VOC
Metal Mining	4,951	49,252	21,732	9,478	1,202	119,761
Oil and Gas Extraction	**132,747**	**389,686**	**4,576**	**3,441**	**238,872**	**114,601**
Non-Fuel, Non-Metal Mining	31,008	21,660	44,305	16,433	9,183	138,684
Textiles	8,164	33,053	1,819	38,505	26,326	7,113
Lumber and Wood Products	139,175	45,533	30,818	18,461	95,228	74,028
Wood Furniture and Fixtures	3,659	3,267	2,950	3,042	84,036	5,895
Pulp and Paper	584,817	365,901	37,869	535,712	177,937	107,676
Printing	8,847	3,629	539	1,772	88,788	1,291
Inorganic Chemicals	242,834	93,763	6,984	150,971	52,973	34,885
Plastic Resins and Man-made Fibers	15,022	36,424	2,027	65,875	71,416	7,580
Pharmaceuticals	6,389	17,091	1,623	24,506	31,645	4,733
Organic Chemicals	112,999	177,094	13,245	129,144	162,488	17,765
Agricultural Chemicals	12,906	38,102	4,733	14,426	62,848	8,312
Petroleum Refining	299,546	334,795	25,271	592,117	292,167	36,421
Rubber and Plastic	2,463	10,977	3,391	24,366	110,739	6,302
Stone, Clay, Glass and Concrete	92,463	335,290	58,398	290,017	21,092	198,404
Iron and Steel	982,410	158,020	36,973	241,436	67,682	85,608
Metal Castings	115,269	10,435	14,667	4,881	17,301	21,554
Nonferrous Metals	311,733	31,121	12,545	303,599	7,882	23,811
Fabricated Metal Products	7,135	11,729	2,811	17,535	108,228	5,043
Electronics and Computers	27,702	7,223	1,230	8,568	46,444	3,464
Motor Vehicle Assembly	19,700	31,127	3,900	29,766	125,755	6,212
Aerospace	4,261	5,705	890	757	3,705	10,804
Shipbuilding and Repair	109	866	762	2,862	4,345	707
Ground Transportation	153,631	594,672	2,338	9,555	101,775	5,542
Water Transportation	179	476	676	712	3,514	3,775
Air Transportation	1,244	960	133	147	1,815	144
Fossil Fuel Electric Power	399,585	5,661,468	221,787	13,477,367	42,726	719,644
Dry Cleaning	145	781	10	725	7,920	40

Source: EPA Office of Air and Radiation, AIRS Database, 1997.

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V. POLLUTION PREVENTION OPPORTUNITIES

The best way to reduce pollution is to prevent it in the first place. Some companies have creatively implemented pollution prevention techniques that improve efficiency and increase profits while at the same time minimizing environmental impacts. This can be done in many ways such as reducing material inputs, re-engineering processes to reuse by-products, improving management practices, and employing substitution of toxic chemicals. Some smaller facilities are able to actually get below regulatory thresholds just by reducing pollutant releases through aggressive pollution prevention policies.

The Pollution Prevention Act of 1990 established a national policy of managing waste through source reduction, which means preventing the generation of waste. The Pollution Prevention Act also established as national policy a hierarchy of waste management options for situations in which source reduction cannot be implemented feasiblely. In the waste management hierarchy, if source reduction is not feasible, the next alternative is recycling of wastes, followed by energy recovery, with waste treatment as a last alternative.

In order to encourage these approaches, this section provides both general and company-specific descriptions of some pollution prevention advances that have been implemented within the oil and gas extraction industry. While the list is not exhaustive, it does provide core information that can be used as the starting point for facilities interested in beginning their own pollution prevention projects. This section provides summary information from activities that may be, or are being implemented by this sector. When possible, information is provided that gives the context in which the technique can be used effectively. Please note that the activities described in this section do not necessarily apply to all facilities that fall within this sector. Facility-specific conditions must be carefully considered when pollution prevention options are evaluated, and the full impacts of the change must examine how each option affects air, land and water pollutant releases.

Waste Management Plans

Pollution prevention opportunities are most effective when they are coordinated in a facility-wide waste management plan. The American Petroleum Institute (API) has published guidelines for waste management plans, in which pollution prevention is an integral part (API, 1991). The ten-step plan involves the following:

1. Company management approval: Management should establish goals for the waste management plan, identify key personnel and resources that are

committed to the plan, and develop a mission statement for its environmental policies.

2. Area Definition: The waste management plan should be designed for a specific area to account for differing regulations and conditions; in most cases, the area would be limited to within one state.

3. Regulatory Analysis: Federal, state and local laws, and landowner and lease agreements, should be evaluated. Based on these evaluations, operating conditions and requirements should be defined.

4. Waste Identification: The source, nature, and quantity of generated wastes within the plan's area should be identified, and a brief description of each type of waste should be written.

5. Waste Classification: Each waste stream should be classified according to its regulatory status, including whether it is a hazardous waste subject to regulation under the Resource Conservation and Recovery Act (RCRA).

6. List and Evaluate Waste Management and Disposal Options: List all waste management practices and determine the environmental acceptability of each option. Consider regulatory restrictions, engineering limitations, economics, and intangible benefits when determining their feasibility.

7. Waste Minimization: Analyze each waste-generating process for opportunities to reduce the volume generated or ways to reuse or recycle wastes. Note that the waste minimization or pollution prevention opportunities that are presented in this section can be used for this step.

8. Select Preferred Waste Management Practices: Choose the preferred management practices identified in Step 6 and incorporate waste minimization options from Step 7 wherever feasible. Specific instructions for implementation should be developed.

9. Prepare and Implement an Area Waste Management Plan: Compile all preferred waste management and minimization practices and write waste management summaries for each waste. Implement the plan on a field level.

10. Review and Update Waste Management Plan: Establish a procedure to periodically review and revise the plan.

V.A. Exploration

Several approaches or technologies can be used by exploration companies to drill more efficiently and to maximize the recovery of oil and natural gas. Oil and gas Exploration is not a waste-intensive activity per se, but efforts made by those involved with exploration can assist in minimizing the number of dry wells that are later drilled.

Drill Site Selection

The volume of drilling waste is directly related to the number of wells drilled. Thus, if fewer wells can be drilled to efficiently produce a discovered reservoir, and if the number of dry holes (wells drilled that do not find commercial quantities of oil or gas) can be minimized, then the total volume of drilling wastes will be reduced. Site selection is a key component of this reduction.

<u>Modeling Software</u>
New computer software is available that converts seismic data into models of subterranean formations. Until 15 years ago, modeling software was limited to large mainframe computers and was inaccessible for small-scale projects. In recent years, software has been created for use on personal computers that can incorporate the various components of remote sensing and logging. Three-dimensional models can now be produced from data that geophysicists previously would have had to analyze manually.

The U.S. Department of Energy has created several significant computer programs for the oil and gas exploration industry. KINETICS models the chemical reactions that take place over millions of years that lead to the creation of oil and gas, and therefore assists in interpreting whether conditions at a site are favorable for oil. Programs like BOAST and MASTER can be used in wells already in production to model flow patterns to determine the best approach for secondary or tertiary recovery efforts. It is estimated that computer programs such as these can result in an increase of three billion barrels of domestic reserves, generate increased tax revenue for the government, and reduce the drilling of unnecessary or unproductive wells (U.S. Department of Energy, 1998).

<u>Iodine Sensing</u>
Empirical evidence indicates that unusual concentrations of iodine on the earth's surface are nearly always associated with petroleum that seeps from subsurface formations. Although the process is still in the experimental stage, surface geochemical analyses can be performed to test for the presence of unusually high concentrations of iodine, which in turn indicates the presence of oil or gas. The iodine test can be used in conjunction with traditional

seismic processes to determine favorable drilling sites. Seismic tests measure for geological formations that can potentially contain large amounts of oil or gas, but can't directly detect these products. Conversely, high iodine levels may indicate that petroleum is present, but not that the geological structures are favorable for petroleum extraction. These two processes therefore can be used in conjunction with each other to better determine the probability of being able to produce oil at a given site before a well is drilled.

Drill Site Construction

Storm Water Runoff Impact Reduction

Measures that can be taken to reduce the impacts associated with storm water runoff can apply to all aspects of oil and gas exploration and production. The following are a few examples of such measures.

- Reduce exposure of materials such as drilling fluids and other chemicals stored on-site to rainfall and storm water runoff. This can be accomplished by storing drums and other materials under cover (such as in a trailer, in a shed or covering with tarps).
- Utilize best management practices (BMPs) such as diversion dikes, containment diking, and curbing to reduce exposure of storm water runoff to cuttings and other waste storage areas.
- Utilize BMPs such as sediment traps, swales, and mulching during construction activities (such as during road building or construction of buildings) to reduce loss of sediment and contamination of runoff.
- Insure that adequate materials and equipment are available to contain and control spills in order to prevent contamination of runoff. An effort should be made here to go beyond any SPCC requirements and be prepared to contain and control all spills (of any waste) on site.

Two references that may be useful for oil and gas exploration and production operations to prevent contamination of storm water runoff are 1) Storm Water Management for Industrial Activities - Developing Pollution Prevention Plans and Best Management Practices (EPA 832-R-92-006) and 2) Storm Water Management for Construction Activities - Developing Pollution Prevention Plans and Best Management Practices (EPA 832-R-92-005).

Downhole Analysis

Recently, several technologies have emerged that allow for more accurate analysis of an oil or gas-bearing formation via equipment lowered into the wellbore of producing wells. These either can lead to improvements in production of the well in question, or assist in determining the best location for an additional well. In either case, the technology helps to reduce the number of wells drilled that do not produce.

Formation Analysis Through Old Well Casings

Some of the geophysical logging procedures and tools now in use for new wells were not available for wells drilled 30 years ago. Therefore, data for the zones between the surface and the production zone of the well may be incomplete. Typically the metal casing limits analysis of the formations in these sealed-off zones. New tools have been developed that allow surveying through casing and that may lead to the discovery of production zones that were missed during the original drilling. The procedure can extend the life of old wells and reduce the need for drilling new ones.

Crosswell Seismic Imaging

Geological imaging techniques via the surface are limited by the thousands of feet of rock between the equipment and the potential production zone. As a result, the best resolution obtainable is approximately 50 feet. With crosswell seismic imaging, sound wave generators and receivers are lowered into several wellbores in a production field. Because the waves need to travel a shorter distance between the generator and receivers, the resolution can be as accurate as five feet. This process can be useful in ensuring that additional wells drilled in a producing field are placed accurately.

V.B. Well Development

Drilling

Closed Loop Drilling Fluid System

When drilling a well that will be shallow and likely will not encounter unusual zones of pressure, a closed system for drilling fluids can be used. At a conventional drilling site, drilling fluid is circulated through the wellbore, then deposited in a reserve pit dug next to the well. This pit is open to the atmosphere, and serves to store excess fluid and to separate out contaminants. While the large storage capacity is important for wells that encounter high pressure and therefore might experience fluctuations in the amount of fluid needed, a reserve pit can be the source of considerable costs at a drilling site. The pit itself must be constructed at the beginning of drilling, and must be closed properly when drilling is completed. Also, because the pit may release higher levels of VOCs and can leak liquids into surface or groundwater, there are increased health, environmental, and financial risks.

In a closed-loop drilling fluid system, the reserve pit is replaced with a series of storage tanks. The tanks represent an additional cost, but because they preclude the need for constructing a pit, reduce the amount of environmental releases, and result in more efficient use of drilling fluid, the technology can save the operator money when conditions allow its use.

A small independent operator in Texas was concerned that reserve pits for drilling fluid were increasing waste management costs and exposing it to liability for surface and ground water contamination. Because the wells to be drilled were relatively shallow and few complications were expected, the operator negotiated with the drilling contractors to use a closed-loop fluid system. The operator realized savings of about $10,000 per well because reserve pits were not constructed and waste management costs were reduced. The operator's liability was also reduced (Texas Railroad Commission, 1997).

Pit Design

If the closed-loop drilling system is not used for drilling fluids, another approach may be to use a V-shaped pit instead of the traditional rectangular pit. The open end of the "V" faces the drilling rig and the cross-sectional view resembles a squared-off funnel (about 10 feet deep with the upper 5 feet having slanted walls to a width of about 20 feet). Because the fluid must travel the full length of the pit, this design prevents mud from channeling between the discharge point and the suction point, and reduces the amount of water that needs to be added to maintain the desired fluid characteristics. In addition, because the V-shaped pit is long and narrow, it is easier to construct and leaves a smaller "footprint" at the site.

A company installed a V-shaped reserve pit and compared the costs with those incurred at similar-sized wells using a traditional pit. The company determined that pit construction time was reduced by about 40 percent, water costs for the well were reduced by about 38 percent, and pit liner costs were reduced by about 43 percent. The total cost savings were about $10,800 per well (Texas Railroad Commission, 1999).

Substitution of Drilling Fluid Additives

Some traditional drilling fluid additives are toxic and require extra care in disposal. In response, the drilling fluid industry has developed replacements for some of the more toxic compounds. These include:

- Replacement of chrome lignosulfonate dispersants with chrome-free lignosulfonates and polysaccharide polymers.
- Use of amines instead of pentachlorophenols and paraformaldehyde as biocides.
- Lubrication with mineral oil and lubra-beads instead of diesel oil.

Substitutions such as those described above can minimize the toxicity of drilling wastes and reduce the risks and costs associated with drilling fluid disposal.

Material Balance and Mud System Monitoring

Monitoring devices used at various points in the drilling fluid circulation system may be used to check for the decrease of fluid levels or other changes in fluid characteristics. Such devices may reduce the need for the addition of water and additives to the fluid, thereby reducing the costs and waste associated with drilling fluid.

Removal of Solids from Drilling Fluid

Careful removal of drill cuttings and other contaminating solids can reduce the need to dilute or replace drilling fluid. Furthermore, if the separated solids are treated thoroughly to remove moisture, the weight of waste can be significantly reduced. In addition to using shale shakers, which are always used to remove rocks and larger fragments, drilling rigs can reduce waste by including several optional components in their mud treatment systems. Desanders and desilters separate increasingly smaller particles. Centrifuges remove the smallest suspended pieces. Finally, mud cleaners break oil-water emulsions and remove many dissolved components. If these devices are in optimal working condition, the drilling mud can be nearly free of suspended materials, and the solid waste can be less than 30 percent moisture by weight.

Polycrystalline Diamond Compact (PDC) Drill Bit

Pulling the drill string to replace the drill bit is one of the more inefficient and potentially dangerous procedures in drilling. Quite a bit of time and energy can be wasted in pulling the entire drill string to the surface and lowering it back into the wellbore. In addition, it is when the drill string is being raised and lowered that well blowouts are an increased risk if not properly done. It is therefore desirable for both efficiency and blowout prevention to minimize drill bit replacement.

PDC bits have been viable commercially for about a decade, and are the most durable bits available. The bit is primarily steel with interlocked diamond studs. The bits typically last between 230 and 260 drilling hours, but have lasted over 1,000 hours without replacement. Because of their durability, diamond bits account for one-third of the drill bit market, and can save drilling companies as much as $1 million per well (U.S. Department of Energy, 1998).

Downhole Drilling Telemetry

Traditionally, drillers have determined the position of the drill bit by removing the drill string from the well, lowering an instrument into the wellbore, retrieving the instrument, then lowering the drill string back into the wellbore. This process is inefficient and increases the risk of a blowout.

The Department of Energy has helped to develop a wireless system that sends pulses through the drilling mud from the drill bit to the surface, in a process called *mudpulse telemetry*. The technology presents several benefits for wells in which its use is practical: data can be collected during drilling, the data are more complete than those from periodic measurements because the pulsing can occur continuously, and advance warnings can be received of impending drill hazards. Without considering the benefit of decreased environmental and health risks, mudpulse technology saves the industry over $400 million per year.

Horizontal Drilling

Oil and natural gas bearing formations typically have a small vertical profile (i.e., are confined to a narrow range of depth), but are spread over a large horizontal area. As a result, wellbores that intersect the oil-producing formation at an angle can drain more of the formation and reduce the need to drill additional wells compared to purely vertical wells.

Horizontal drilling is costly, because it requires advanced geological sensing equipment and constant attention to the placement of the drill bit. However, the increased cost is often more than offset by increased production and the reduced need for drilling multiple wells.

In the Dundee Formation of Michigan, as much as 85 percent of the known oil remained in the formation after many years of production. Many wells were on the verge of being plugged, with production near five barrels of oil per day per well. A DOE co-sponsored project drilled a horizontal well in the formation, which produced 100 barrels per day, and had estimated recoverable reserves of 200,000 barrels of oil. The program attracted other well developers, and 20 to 30 additional horizontal wells are being drilled in the formation. It is estimated that the application of horizontal drilling to this formation may yield an additional 80 to 100 million barrels of oil (Department of Energy, 1998).

Reuse of Drilling Fluids

Drilling fluid is often disposed of when a well is completed, and fresh fluid used for any adjacent wells. Filtration processes have allowed drilling fluid to be reconditioned, so that it can be used for multiple wells before being discarded. Other possible uses for used drilling fluids are to plug unproductive wells or to spud in new wells. Reuse of oil-based and synthetic-based drilling fluids to drill additional wells is common because of the high cost of the base fluids.

One drilling company in Alaska sought to filter and recondition its drilling fluid in order to use it for several wells. The fluid was used on average over two times, resulting in a decrease of fluid used from 50,000 barrels of fluid to 22,000 barrels. Because the cost of filtering is only six percent of the cost of purchasing new fluid, the fluid treatment system reduced the fluid costs for this operator from $7 million to $3.25 million (SAIC, 1997).

Preventive Maintenance and Leak Containment

Engines, tanks, pumps and other equipment used in the drilling process may leak lubricating oil or fuel. Soil contamination and waste generation may be avoided and valuable chemicals may be recovered by performing regular preventive maintenance and installing leak containment devices. Examples of preventive maintenance include routine checks and replacement of leaking valves, hoses, or connections, while containment measures may include the installation of drip pans underneath engines, containers, valves, and other potential sources of leaks. These practices and devices are important pollution prevention options at production and maintenance operations as well as at drilling sites.

Inventory Control

Facilities may maintain an excess on-site volume of chemicals and materials. This may lead to unnecessary regulatory compliance concerns, operating costs, and waste generation. By tracking the inventory of chemicals and materials, particularly with the use of computer programs, an operator may use materials more efficiently and reduce waste generation. In addition, an operator may negotiate with vendors to accept empty and partially-filled containers for reclamation and reuse, because commercial chemical products that are returned to a vendor or manufacturer may not be considered solid wastes.

An operation encompassing drilling, gas production, and compression activities determined that its on-site supply of chemicals was excessive and that much of its hazardous waste generation was unnecessary. The company made several changes: it identified alternative, less toxic chemicals; eliminated the use of organic solvents; identified processes for which individual chemicals could be used in multiple situations; established a purchasing procedure in which a new chemical is purchased only after evaluating information including material safety data sheets (MSDSs) and other information sources supplied by vendors; and tracked all purchased chemicals to ensure efficient usage. As a result of the program, the company eliminated the use of 32 unnecessary chemicals and products, reduced regulatory concerns, minimized waste disposal costs, and achieved the cooperation of vendors, who worked to supply the company with satisfactory chemicals (Texas Railroad Commission, 1999).

Completion

Lead-Free Pipe Dope

Pipe dope is used in drill string connections. The American Petroleum Institute (API)-specified pipe dope contains approximately 30 percent lead, which raises human health and environmental concerns. New lead-free, biodegradable pipe dopes are now available, however, which may be used when conditions do not require the use of the API-specified material. In particular, the use of pipe dope on thread protectors may allow for the recycling of thread protectors with fewer regulatory concerns.

Cementing "On-the-Fly"

When well casing is cemented in, the cement used is often pre-mixed with additives to specification. There may be a substantial surplus of unused, pre-mixed cement if the quantity required for the project was overestimated. One solution used by some service companies is to mix neat (concentrated) cement with additives on-the-fly, through the use of automatic density control systems. The mixing process can be stopped as soon as the cementing job is complete, and the unused raw materials can be used at a later cementing job rather than disposed of as waste. Cementing on-the-fly is becoming common practice.

V.C. Petroleum Production

Produced Water Management

Produced water constitutes the vast majority of oil and gas extraction waste, and traditionally the volume has been fixed and unavoidable. However, there have been developments that might help to reduce the amount of produced water that is brought to the surface, and reduce the wastes associated with treating produced water that does reach the surface.

Downhole Produced Water Separation

A new procedure made possible by the miniaturization of motors is the separating and pumping of produced water downhole, without bringing it to the surface. There are three significant variations, but in each case excess water is separated from the desired product in the wellbore and injected into another geological formation, typically below the production zone.

In formations where oil and water are mostly separate, two perforations in the well can be made; oil is removed through one and transported to the surface, and water is removed through the other perforation and injected in the disposal zone. It should be noted that the water disposal system must be monitored to ensure that oil is not lost.

In another method, a hydrocyclone is used downhole to separate free water from any oil- or gas-containing fluid by centrifugal force. The water is injected into a disposal zone, and the product is pumped to the surface.

Finally, in gas wells, simple gravity can be used to remove a substantial amount of water. Gas rises to the surface of the separation device, and water is injected from the bottom into a lower disposal zone.

With these methods, some water is always still brought to the surface. Also, the technology is still in development. Nevertheless, downhole separation can be an effective and economically attractive method of reducing produced water volumes.

<u>Produced Water Filter Management</u>
Many wells employ filters to remove some waste from produced water before the water is injected into an underground well. Because the water may contain varying amounts of filterable components, the filters must be changed regularly in order to prevent the system from backing up. Many wells replace the filters at fixed intervals; for example, twice a month. However, it is possible to reduce the frequency of filter changes by measuring the difference in pressure between the input and output sides of the filter, and only changing the filter when a certain pressure is reached. Costs are incurred when valves are installed, but the savings involved in labor, filters, and filter disposal often offset the cost of valve installation.

A small independent operator wanted to reduce the number of filters used for its produced water injection system. Previously, the operator had changed the filters twice a month at its 36 injection wells, at a cost of $4,148 per year (1,700 filters at $2.44 per filter). The operator installed valves on the filter units, at a total cost of $1,800. The following year, the operator only generated 28 waste filters, and saved about $4,000 per year in filter purchases, plus additional labor time and waste management costs (Texas Railroad Commission, 1997).

Natural Gas Conditioning

<u>Reducing Glycol Circulation Rates</u>
Glycol is used to remove water from natural gas. However, methane and VOCs are removed as well, in proportion to the amount of glycol circulated through the system. These methane and VOC components are removed from the glycol during a reconditioning process, and may be either returned to the production stream or vented to the atmosphere.

Research by the EPA voluntary industry partnership Natural Gas STAR has indicated that operators often maintain a circulation rate that is at least two times higher than is needed to attain mandated water content levels. Therefore, it is desirable to perform calculations to determine the minimum circulation rate needed. Savings can be realized on several fronts:

- Less salable methane lost to the atmosphere
- Less glycol needed
- Improved dehydrator unit efficiency
- Lower fuel pump use.

The potential savings for a dehydrator unit can range from $260 to $26,280 per year (Natural Gas STAR, 1997).

<u>Adjusting Pneumatic Devices</u>
For both oil and gas field operations pressurized natural gas is used regularly in pneumatic devices to regulate pressure, control valves, and equilibrate liquid levels. Leaks and releases from this practice, particularly from inefficient or "high-bleed" devices, are the single largest source of methane emissions by the industry. Methane is released at the estimated rate of 31 billion cubic feet (Bcf) per year from pneumatic devices. Several strategies exist to reduce such emissions, including the replacement of high-bleed devices with equivalent low-bleed ones and maintenance of existing devices to replace leaking seals and tune valves. Natural Gas STAR estimates that partners of the program have saved 11.2 Bcf to date through improvements to pneumatic devices, saving approximately $22.4 million. For most of the improvements, the payback period is between six months and a year (Natural Gas STAR, 1997).

Energy-Efficient Production

<u>Automatic Casing Swab</u>
In wells where natural formation pressure is insufficient to lift the product to the surface, it might be possible to install a small device downhole to delay the purchase of costly pumping or injection equipment. The Automatic Casing Swab (ACS) seals off the production zone of the well, which causes pressure to build up in the formation. At a threshold pressure, the ACS opens, and product flows to the surface without mechanical assistance. When the flow slows and pressure decreases, the ACS closes until pressure increases again. The device was created by the Sandia National Laboratories under a grant from DOE, and as of the end of 1997 has been applied to 350 wells. These wells are producing more than 3.5 million cubic feet of natural gas per year that otherwise would have been uneconomical to extract. The device may also lead to decreased energy consumption in other wells in situations where it reduces the need for energy-intensive mechanical pumps.

Solid Waste Reduction

Oily Sludge Minimization

When oil first is brought to the surface, fine particles, oil, and water form a stable sludge that settles out in storage tanks and separation equipment. There are two approaches to minimizing the loss of product that occurs when oil becomes entrained in the sludge: preventing the formation of sludge and treating the sludge to recover the oil.

Two significant methods can minimize the formation of sludge in a storage tank at a production site. First, recirculating pumps can be installed in tanks. By increasing circulation, heavier components remain in suspension longer and do not collect on the bottom of the tanks as quickly. Second, eliminating air contact with oil in the tanks can reduce the formation of sludge. Oxygen can play a role in the formation of sludge, so minimizing the introduction of atmospheric oxygen can reduce sludge levels. Furthermore, reducing contact to the atmosphere can minimize emissions of VOCs.

In many locations, recyclers can treat sludge to remove oil at a crude oil reclamation plant. Crude oil reclamation serves two purposes; the extracted oil can be sold, and disposal costs for sludge is minimized because much of the liquid component is removed. In addition, salable material that has solidified, e.g., paraffin, may be reclaimed during this process. The separation process typically is performed with the use of centrifuges, heat, or filters. One example is a filter press, which presses solids into a cake and extracts oil and water as an aqueous filtrate. The water and oil are then separated further.

A facility on the West Coast installed a filter press to retrieve oil from sludge and reduce disposal costs. The press reduced the volume of waste from 44,900 to 13,500 barrels per year, a reduction of 70 percent. Disposal costs were reduced by $564,200 per year. Approximately 81 percent of the oil in the sludge was recovered, so that at a price of $15 per barrel, the recovered oil represented additional revenues of $108,000 per year. Based on a capital cost for the press of approximately $3,000,000 and operating costs of $400,000 per year, the system is saving approximately $272,000 per year and the capital cost has a payoff period of about 3.5 years.

V.D. Maintenance

Maintenance procedures, particularly workovers, may be a source of potential pollutants for industry including acids, VOCs, and solutions with high concentrations of salts and metals. The following opportunities describe steps that can minimize the need for workovers, or help notify operators when maintenance is necessary to limit releases.

Preplanning

Careful preplanning efforts undertaken prior to a workover may reduce the amount of materials necessary at the site, and therefore may reduce waste and the chance of spilling. For example, by estimating the amount of acid required for acid stimulation based on the known reservoir conditions, the transportation, storage, and disposal of excess acid may be reduced.

Paraffin and Scale Accumulation Prevention

The buildup of paraffins in production equipment, particularly in older wells, is a serious concern, and when untreated, paraffin buildups can damage pumping equipment and rupture flowlines. Therefore, it is desirable to minimize the buildup of paraffins. One possible solution is the installation of a magnetic fluid conditioner (MFC), which creates a strong permanent magnetic field around the pump. This magnetic field alters the solubility and viscosity of crude oil, so that paraffin, scale, and other contaminants do not precipitate in the flowlines. The device requires a significant capital investment, must be custom-made for each well, and is not always successful, but the reduced frequency of maintenance and the reduced risk of flowline rupture (and the associated mitigation costs) can make an MFC a wise choice for wells with paraffin and scale buildup problems.

A small independent operator was suffering from damaged pumping equipment and ruptured flowlines as a result of paraffin buildup, and had to treat the well every ten days with solvent/hot oil to remove the deposits. The operator installed an MFC in the well for $5,000. Seven weeks later for an unrelated reason, the operator pulled the tubing from the well, and minimal paraffin deposition was observed. The investment was recovered in six months due to reduced maintenance costs, and because flow had improved, revenue increased as well (Texas Railroad Commission, 1997).

High-level alarm

A helpful device for preventing releases and loss of product is an alarm and automatic shut-off that shuts-in production equipment when an irregularity is detected. The equipment can only be restarted manually, to ensure that the problem is addressed. A facility-wide alarm is particularly important when the operator is offsite and the well is only monitored periodically.

Microbially-Treated Produced Water

The separation of oil from produced water is not completely efficient; oil concentrations in produced water can be at least 10 ppm. This oil can clog disposal wells and increase electricity costs because injection pumps must contend with increased pressure in these clogged wells. If oil-eating microbes are introduced to the produced water, oil content can be reduced, injection wells may become clogged less frequently (thereby reducing workover costs), and electricity costs are reduced because the pump can work more efficiently.

A small operator wanted to reduce the frequency of workovers and trim electricity costs due to oil clogging in two injection wells. For approximately $150 per month for the two wells, the company added oil-scavenging microbes to the produced water. The operator realized a reduction of $400 per month in electricity costs due to the reduced pressure in the injection well, for a net savings of $250 per month. The procedure also has helped to minimize the number of injection well workovers.

<u>Coiled Tubing Units</u>

As mentioned in previous sections, pulling the drill string or production tubing can increase the chance of a blowout or other spills. Coiled tubing units allow workovers to be performed while keeping production tubing in place. By using coiled tubing units during workovers, the use of a workover rig and the pulling of production tubing are avoided.

<u>Product Substitution</u>

Many materials used in the workover process, particularly solvents used for cleaning and for paints, are classified as hazardous wastes when spent. Alternatives are available that are not classified as hazardous waste, and which are safer for the environment and present fewer regulatory concerns. Alternatives for cleaning solvents include citrus-based cleaning compounds and steam, or a substitute for the solvent Varsol (also called petroleum spirits or Stoddard solvent) is available as a "high flash point Varsol," thereby sufficiently reducing the solution's ignitability hazardous waste characteristic. For solvent-based paints, a common substitution is the use of water-based paints, which reduce or eliminate the need for solvents and organic thinners.

<u>Chemical Metering or Dosing Systems</u>

The dispensing of some workover fluids, such as corrosion inhibitors, by an occasional bulk addition can result in the inefficient use of the chemical and an inadequate workover job. As an alternative, an automatic dosing system that releases a small, continuous stream of fluid can reduce the amount of needed fluid and may improve workover results.

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VI. SUMMARY OF FEDERAL STATUTES AND REGULATIONS

This section discusses the federal regulations that may apply to this sector. The purpose of this section is to highlight and briefly describe the applicable federal requirements, and to provide citations for more detailed information. The three following sections are included:

- Section VI.A contains a general overview of major statutes
- Section VI.B contains a list of regulations specific to this industry
- Section VI.C contains a list of pending and proposed regulatory requirements.

The descriptions within Section VI are intended solely for general information. Depending upon the nature or scope of the activities at a particular facility, these summaries may or may not necessarily describe all applicable environmental requirements. Moreover, they do not constitute formal interpretations or clarifications of the statutes and regulations. For further information, readers should consult the Code of Federal Regulations and other state or local regulatory agencies. EPA Hotline contacts are also provided for each major statute.

VI.A. General Description of Major Statutes

Clean Water Act

The primary objective of the Federal Water Pollution Control Act, commonly referred to as the Clean Water Act (CWA), is to restore and maintain the chemical, physical, and biological integrity of the nation's surface waters. Pollutants regulated under the CWA are classified as either “toxic” pollutants; "conventional" pollutants, such as biochemical oxygen demand (BOD), total suspended solids (TSS), fecal coliform, oil and grease, and pH; or "non-conventional" pollutants, including any pollutant not identified as either conventional or priority.

The CWA regulates both direct and “indirect” dischargers (those who discharge to publicly owned treatment works). The National Pollutant Discharge Elimination System (NPDES) permitting program (CWA section 402) controls direct discharges into navigable waters. Direct discharges or "point source" discharges are from sources such as pipes and sewers. NPDES permits, issued by either EPA or an authorized state (EPA has authorized 43 states and 1 territory to administer the NPDES program), contain industry-specific, technology-based and water quality-based limits and establish pollutant monitoring and reporting requirements. A facility that proposes to discharge into the nation's waters must obtain a permit prior to initiating a discharge. A permit applicant must provide quantitative analytical data identifying the types of pollutants present in the facility's effluent. The permit will then set forth the conditions and effluent limitations under which a facility may make a discharge.

Water quality-based discharge limits are based on federal or state water quality criteria or standards, that were designed to protect designated uses of surface waters, such as supporting aquatic life or recreation. These standards, unlike the technology-based standards, generally do not take into account technological feasibility or costs. Water quality criteria and standards vary from state to state, and site to site, depending on the use classification of the receiving body of water. Most states follow EPA guidelines which propose aquatic life and human health criteria for many of the 126 priority pollutants.

Storm Water Discharges

In 1987 the CWA was amended to require EPA to establish a program to address storm water discharges. In response, EPA promulgated NPDES permitting regulations for storm water discharges. These regulations require that facilities with the following types of storm water discharges, among others, apply for an NPDES permit: (1) a discharge associated with industrial activity; (2) a discharge from a large or medium municipal storm sewer system; or (3) a discharge which EPA or the state determines to contribute to a violation of a water quality standard or is a significant contributor of pollutants to waters of the United States.

The term “storm water discharge associated with industrial activity” means a storm water discharge from one of 11 categories of industrial activity defined at 40 CFR Part 122.26. Six of the categories are defined by SIC codes while the other five are identified through narrative descriptions of the regulated industrial activity. If the primary SIC code of the facility is one of those identified in the regulations, the facility is subject to the storm water permit application requirements. If any activity at a facility is covered by one of the five narrative categories, storm water discharges from those areas where the activities occur are subject to storm water discharge permit application requirements.

Those facilities/activities that are subject to storm water discharge permit application requirements are identified below. To determine whether a particular facility falls within one of these categories, the regulation should be consulted.

Category i: Facilities subject to storm water effluent guidelines, new source performance standards, or toxic pollutant effluent standards.

Category ii: Facilities classified as SIC 24-lumber and wood products (except wood kitchen cabinets); SIC 26-paper and allied products (except paperboard containers and products); SIC 28-chemicals and allied products (except drugs and paints); SIC 29-petroleum refining; SIC 311-leather tanning and finishing; SIC 32 (except 323)-stone, clay, glass, and concrete; SIC 33-primary metals; SIC 3441-fabricated structural metal; and SIC 373-ship and boat building and repairing.

Category iii: Facilities classified as SIC 10-metal mining; SIC 12-coal mining; SIC 13-oil and gas extraction; and SIC 14-nonmetallic mineral mining.

Category iv: Hazardous waste treatment, storage, or disposal facilities.

Category v: Landfills, land application sites, and open dumps that receive or have received industrial wastes.

Category vi: Facilities classified as SIC 5015-used motor vehicle parts; and SIC 5093-automotive scrap and waste material recycling facilities.

Category vii: Steam electric power generating facilities.

Category viii: Facilities classified as SIC 40-railroad transportation; SIC 41-local passenger transportation; SIC 42-trucking and warehousing (except public warehousing and storage); SIC 43-U.S. Postal Service; SIC 44-water transportation; SIC 45-transportation by air; and SIC 5171-petroleum bulk storage stations and terminals.

Category ix: Sewage treatment works.

Category x: Construction activities except operations that result in the disturbance of less than five acres of total land area.

Category xi: Facilities classified as SIC 20-food and kindred products; SIC 21-tobacco products; SIC 22-textile mill products; SIC 23-apparel related products; SIC 2434-wood kitchen cabinets manufacturing; SIC 25-furniture and fixtures; SIC 265-paperboard containers and boxes; SIC 267-converted paper and paperboard products; SIC 27-printing, publishing, and allied industries; SIC 283-drugs; SIC 285-paints, varnishes, lacquer, enamels, and allied products; SIC 30-rubber and plastics; SIC 31-leather and leather products (except leather and tanning and finishing); SIC 323-glass products; SIC 34-fabricated metal products (except fabricated structural metal); SIC 35-industrial and commercial machinery and computer equipment; SIC 36-electronic and other electrical equipment and components; SIC 37-transportation equipment (except ship and boat building and repairing); SIC 38-measuring, analyzing, and controlling instruments; SIC 39-miscellaneous manufacturing industries; and SIC 4221-4225-public warehousing and storage.

Pretreatment Program

Another type of discharge that is regulated by the CWA is one that goes to a publicly owned treatment works (POTW). The national pretreatment program (CWA section 307(b)) controls the indirect discharge of pollutants to POTWs by "industrial users." Facilities regulated under section 307(b) must meet certain pretreatment standards. The goal of the pretreatment program is to protect municipal wastewater treatment plants from damage that may occur when hazardous, toxic, or other wastes are discharged into a sewer system and to protect the quality of sludge generated by these plants.

EPA has developed technology-based standards for industrial users of POTWs. Different standards apply to existing and new sources within each category. "Categorical" pretreatment standards applicable to an industry on a nationwide basis are developed by EPA. In addition, another kind of pretreatment standard, "local limits," are developed by the POTW in order to assist the POTW in achieving the effluent limitations in its NPDES permit.

Regardless of whether a state is authorized to implement either the NPDES or the pretreatment program, if it develops its own program, it may enforce requirements more stringent than federal standards.

Wetlands

Wetlands, commonly called swamps, marshes, fens, bogs, vernal pools, playas, and prairie potholes, are a subset of “waters of the United States,” as defined in Section 404 of the CWA. The placement of dredge and fill material into wetlands and other water bodies (i.e., waters of the United States) is regulated by the U.S. Army Corps of Engineers (Corps) under 33 CFR Part 328. The Corps regulates wetlands by administering the CWA Section 404 permit program for activities that impact wetlands. EPA’s authority under Section 404 includes veto power of Corps permits, authority to interpret statutory exemptions and jurisdiction, enforcement actions, and delegating the Section 404 program to the states.

EPA’s Office of Water, at (202) 260-5700, will direct callers with questions about the CWA to the appropriate EPA office. EPA also maintains a bibliographic database of Office of Water publications which can be accessed through the Ground Water and Drinking Water Resource Center, at (202) 260-7786.

Oil Pollution Prevention Regulation

Section 311(b) of the CWA prohibits the discharge of oil, in such quantities as may be harmful, into the navigable waters of the United States and adjoining shorelines. The EPA Discharge of Oil regulation, 40 CFR Part 110, provides information regarding these discharges. The Oil Pollution Prevention regulation, 40 CFR Part 112, under the authority of Section 311(j) of the CWA, requires regulated facilities to prepare and implement Spill Prevention Control and Countermeasure (SPCC) plans. The intent of a SPCC plan is to prevent the discharge of oil from onshore and offshore non-transportation-related facilities. In 1990 Congress passed the Oil Pollution Act which amended Section 311(j) of the CWA to require facilities that because of their location could reasonably be expected to cause "substantial harm" to the environment by a discharge of oil to develop and implement Facility Response Plans (FRP). The intent of a FRP is to provide for planned responses to discharges of oil.

A facility is SPCC-regulated if the facility, due to its location, could reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines, and the facility meets one of the following criteria regarding oil storage: (1) the capacity of any aboveground storage tank exceeds 660 gallons, or (2) the total aboveground storage capacity exceeds 1,320 gallons, or (3) the underground storage capacity exceeds 42,000 gallons. 40 CFR Part 112.7 contains the format and content requirements for a SPCC plan. In New Jersey, SPCC plans can be combined with DPCC plans, required by the state, provided there is an appropriate cross-reference index to the requirements of both regulations at the front of the plan.

According to the FRP regulation, a facility can cause "substantial harm" if it meets one of the following criteria: (1) the facility has a total oil storage capacity greater than or equal to 42,000 gallons and transfers oil over water to or from vessels; or (2) the facility has a total oil storage capacity greater than or equal to 1 million gallons and meets any one of the following conditions: (i) does not have adequate secondary containment, (ii) a discharge could cause "injury" to fish and wildlife and sensitive environments, (iii) shut down a public drinking water intake, or (iv) has had a reportable oil spill greater than or equal to 10,000 gallons in the past 5 years. Appendix F of 40 CFR Part 112 contains the format and content requirements for a FRP. FRPs that meet EPA's requirements can be combined with U.S. Coast Guard FRPs or other contingency plans, provided there is an appropriate cross-reference index to the requirements of all applicable regulations at the front of the plan.

For additional information regarding SPCC plans, contact EPA's RCRA, Superfund, and EPCRA Hotline, at (800) 424-9346. Additional documents and resources can be obtained from the hotline's homepage at www.epa.gov/epaoswer/hotline. The hotline operates weekdays from 9:00 a.m. to 6:00 p.m., EST, excluding federal holidays.

Safe Drinking Water Act

The Safe Drinking Water Act (SDWA) mandates that EPA establish regulations to protect human health from contaminants in drinking water. The law authorizes EPA to develop national drinking water standards and to create a joint federal-state system to ensure compliance with these standards. The SDWA also directs EPA to protect underground sources of drinking water through the control of underground injection of fluid wastes.

EPA has developed primary and secondary drinking water standards under its SDWA authority. EPA and authorized states enforce the primary drinking water standards, which are contaminant-specific concentration limits that apply to certain public drinking water supplies. Primary drinking water standards consist of maximum contaminant level goals (MCLGs), which are non-enforceable health-based goals, and maximum contaminant levels (MCLs), which are enforceable limits set generally as close to MCLGs as possible, considering cost and feasibility of attainment.

Part C of the SDWA mandates EPA to protect underground sources of drinking water from inadequate injection practices. EPA has published regulations codified in 40 CFR Parts 144 to 148 to comply with this mandate. The Underground Injection Control (UIC) regulations break down injection wells into five different types, depending on the fluid injected and the formation that receives it. The regulations also include construction, monitoring, testing, and operating requirements for injection well operators. All injection wells have to be authorized by permit or by rule depending on their potential to threaten Underground Sources of Drinking Water (USDW). RCRA also regulates hazardous waste injection wells and a UIC permit is considered to meet the requirements of a RCRA permit. EPA has authorized delegation of the UIC for all wells in 35 states, implements the program in 10 states and all Indian lands, and shares responsibility with 5 states.

The SDWA also provides for a federally-implemented Sole Source Aquifer program, which prohibits federal funds from being expended on projects that may contaminate the sole or principal source of drinking water for a given area, and for a state-implemented Wellhead Protection program, designed to protect drinking water wells and drinking water recharge areas.

The SDWA Amendments of 1996 require states to develop and implement source water assessment programs (SWAPs) to analyze existing and potential threats to the quality of the public drinking water throughout the state. Every state is required to submit a program to EPA and to complete all assessments within 3 ½ years of EPA approval of the program. SWAPs include: (1) delineating the source water protection area, (2) conducting a contaminant source inventory, (3) determining the susceptibility of the public water supply to contamination from the inventories sources, and (4) releasing the results of the assessments to the public.

EPA's Safe Drinking Water Hotline, at (800) 426-4791, answers questions and distributes guidance pertaining to SDWA standards. The Hotline operates from 9:00 a.m. through 5:30 p.m., EST, excluding federal holidays. Visit the website at www.epa.gov/ogwdw for additional material.

Resource Conservation and Recovery Act

The Solid Waste Disposal Act (SWDA), as amended by the Resource Conservation and Recovery Act (RCRA) of 1976, addresses solid and hazardous waste management activities. The Act is commonly referred to as RCRA. The Hazardous and Solid Waste Amendments (HSWA) of 1984 strengthened RCRA's waste management provisions and added Subtitle I, which governs underground storage tanks (USTs).

Regulations promulgated pursuant to Subtitle C of RCRA (40 CFR Parts 260-299) establish a "cradle-to-grave" system governing hazardous waste from the point of generation to disposal. RCRA hazardous wastes include the specific materials listed in the regulations (discarded commercial chemical products, designated with the code "P" or "U"; hazardous wastes from specific industries/sources, designated with the code "K"; or hazardous wastes from non-specific sources, designated with the code "F") or materials which exhibit a hazardous waste characteristic (ignitability, corrosivity, reactivity, or toxicity and designated with the code "D").

Entities that generate hazardous waste are subject to waste accumulation, manifesting, and recordkeeping standards. A hazardous waste facility may accumulate hazardous waste for up to 90 days (or 180 days depending on the amount generated per month) without a permit or interim status. Generators may also treat hazardous waste in accumulation tanks or containers (in accordance with the requirements of 40 CFR Part 262.34) without a permit or interim status. Facilities that treat, store, or dispose of hazardous waste are generally required to obtain a RCRA permit.

Subtitle C permits are required for treatment, storage, or disposal facilities. These permits contain general facility standards such as contingency plans, emergency procedures, recordkeeping and reporting requirements, financial assurance mechanisms, and unit-specific standards. RCRA also contains provisions (40 CFR Subparts I and S) for conducting corrective actions which govern the cleanup of releases of hazardous waste or constituents from solid waste management units at RCRA treatment, storage, or disposal facilities.

Although RCRA is a federal statute, many states implement the RCRA program. Currently, EPA has delegated its authority to implement various provisions of RCRA to 47 of the 50 states and two U.S. territories. Delegation has not been given to Alaska, Hawaii, or Iowa.

Most RCRA requirements are not industry specific but apply to any company that generates, transports, treats, stores, or disposes of hazardous waste. Here are some important RCRA regulatory requirements:

- **Criteria for Classification of Solid Waste Disposal Facilities and Practices** (40 CFR Part 257) establishes the criteria for determining which solid waste disposal facilities and practices pose a reasonable probability of adverse effects on health or the environment. The criteria were adopted to ensure non-municipal, non-hazardous waste disposal units that receive conditionally exempt small quantity generator waste do not present risks to human health and environment.

- **Criteria for Municipal Solid Waste Landfills** (40 CFR Part 258) establishes minimum national criteria for all municipal solid waste landfill units, including those that are used to dispose of sewage sludge.

- **Identification of Solid and Hazardous Wastes** (40 CFR Part 261) establishes the standard to determine whether the material in question is considered a solid waste and, if so, whether it is a hazardous waste or is exempted from regulation.

- **Standards for Generators of Hazardous Waste** (40 CFR Part 262) establishes the responsibilities of hazardous waste generators including obtaining an EPA identification number, preparing a manifest, ensuring proper packaging and labeling, meeting standards for waste accumulation units, and recordkeeping and reporting requirements. Generators can accumulate hazardous waste on-site for up to 90 days (or 180 days depending on the amount of waste generated) without obtaining a permit.

- **Land Disposal Restrictions** (LDRs) (40 CFR Part 268) are regulations prohibiting the disposal of hazardous waste on land without prior treatment. Under the LDRs program, materials must meet treatment standards prior to placement in a RCRA land disposal unit (landfill, land treatment unit, waste pile, or surface impoundment). Generators of waste subject to the LDRs must provide notification of such to the designated TSD facility to ensure proper treatment prior to disposal.

- **Used Oil Management Standards** (40 CFR Part 279) impose management requirements affecting the storage, transportation, burning, processing, and re-refining of the used oil. For parties that merely generate used oil, regulations establish storage standards. For a party considered a used oil processor, re-refiner, burner, or marketer (one who generates and sells off-specification used oil directly to a used oil burner), additional tracking and paperwork requirements must be satisfied.

- RCRA contains unit-specific standards for all units used to store, treat, or dispose of hazardous waste, including **Tanks and Containers**. Tanks and containers used to store hazardous waste with a high volatile organic concentration must meet emission standards under RCRA. Regulations (40 CFR Part 264-265, Subpart CC) require generators to test the waste to determine the concentration of the waste, to satisfy tank and container emissions standards, and to inspect and monitor regulated units. These regulations apply to all facilities who store such waste, including large quantity generators accumulating waste prior to shipment offsite.

- **Underground Storage Tanks** (USTs) containing petroleum products (including gasoline, diesel, and used oil) and hazardous substances are regulated under Subtitle I of RCRA. Subtitle I regulations (40 CFR Part 280) contain tank design and release detection requirements, as well as financial responsibility and corrective action standards for USTs. The UST program also includes upgrade requirements for existing tanks that were to be met by December 22, 1998.

- **Boilers and Industrial Furnaces** (BIFs) that use or burn fuel containing hazardous waste must comply with design and operating standards. BIF regulations (40 CFR Part 266, Subpart H) address unit design, provide performance standards, require emissions monitoring, and, in some cases, restrict the type of waste that may be burned.

EPA's RCRA, Superfund, and EPCRA Hotline, at (800) 424-9346, responds to questions and distributes guidance regarding all RCRA regulations. Additional documents and resources can be obtained from the hotline's homepage at www.epa.gov/epaoswer/hotline. The RCRA Hotline operates weekdays from 9:00 a.m. to 6:00 p.m., EST, excluding federal holidays.

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), a 1980 law commonly known as Superfund, authorizes EPA to respond to releases, or threatened releases, of hazardous substances that may endanger public health, welfare, or the environment. CERCLA also enables EPA to force parties responsible for environmental contamination to clean it up or to reimburse the Superfund for response or remediation costs incurred by EPA. The Superfund Amendments and Reauthorization Act

(SARA) of 1986 revised various sections of CERCLA, extended the taxing authority for the Superfund, and created a free-standing law, SARA Title III, also known as the Emergency Planning and Community Right-to-Know Act (EPCRA).

The CERCLA hazardous substance release reporting regulations (40 CFR Part 302) direct the person in charge of a facility to report to the National Response Center (NRC) any environmental release of a hazardous substance which equals or exceeds a reportable quantity. Reportable quantities are listed in 40 CFR Part 302.4. A release report may trigger a response by EPA or by one or more federal or state emergency response authorities.

EPA implements hazardous substance responses according to procedures outlined in the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) (40 CFR Part 300). The NCP includes provisions for cleanups. The National Priorities List (NPL) currently includes approximately 1,300 sites. Both EPA and states can act at other sites; however, EPA provides responsible parties the opportunity to conduct cleanups and encourages community involvement throughout the Superfund response process.

EPA's RCRA, Superfund and EPCRA Hotline, at (800) 424-9346, answers questions and references guidance pertaining to the Superfund program. Documents and resources can be obtained from the hotline's homepage at www.epa.gov/epaoswer/hotline. The Superfund Hotline operates weekdays from 9:00 a.m. to 6:00 p.m., EST, excluding federal holidays.

Emergency Planning And Community Right-To-Know Act

The Superfund Amendments and Reauthorization Act (SARA) of 1986 created the Emergency Planning and Community Right-to-Know Act (EPCRA, also known as SARA Title III), a statute designed to improve community access to information about chemical hazards and to facilitate the development of chemical emergency response plans by state and local governments. Under EPCRA, states establish State Emergency Response Commissions (SERCs), responsible for coordinating certain emergency response activities and for appointing Local Emergency Planning Committees (LEPCs).

EPCRA and the EPCRA regulations (40 CFR Parts 350-372) establish four types of reporting obligations for facilities which store or manage specified chemicals:

- **EPCRA section 302** requires facilities to notify the SERC and LEPC of the presence of any extremely hazardous substance at the facility in an amount in excess of the established threshold planning quantity.

The list of extremely hazardous substances and their threshold planning quantities is found at 40 CFR Part 355, Appendices A and B.

- **EPCRA section 303** requires that each LEPC develop an emergency plan. The plan must contain (but is not limited to) the identification of facilities within the planning district, likely routes for transporting extremely hazardous substances, a description of the methods and procedures to be followed by facility owners and operators, and the designation of community and facility emergency response coordinators.

- **EPCRA section 304** requires the facility to notify the SERC and the LEPC in the event of a release exceeding the reportable quantity of a CERCLA hazardous substance (defined at 40 CFR Part 302) or an EPCRA extremely hazardous substance.

- **EPCRA sections 311 and 312** require a facility at which a hazardous chemical, as defined by the Occupational Safety and Health Act, is present in an amount exceeding a specified threshold to submit to the SERC, LEPC and local fire department material safety data sheets (MSDSs) or lists of MSDSs and hazardous chemical inventory forms (also known as Tier I and II forms). This information helps the local government respond in the event of a spill or release of the chemical.

- **EPCRA section 313** requires certain covered facilities, including SIC codes 20 through 39 and, the seven industry groups added in 1997 (including metal mining (SIC code 10, except for SIC codes 1011, 1081, and 1094), coal mining (SIC code 12, except for SIC code 1241 and extraction activities), electrical utilities that combust coal and/or oil (SIC codes 4911, 4931, and 4939), RCRA Subtitle C hazardous waste treatment and disposal facilities (SIC code 4953), chemicals and allied products wholesale distributors (SIC code 5169), petroleum bulk plants and terminals (SIC code 5171), and solvent recovery services (SIC code 7389)), which have ten or more employees, and which manufacture, process, or use specified chemicals in amounts greater than threshold quantities, to submit an annual toxic chemical release report. This report, commonly known as the Form R, covers releases and transfers of toxic chemicals to various facilities and environmental media. EPA maintains the data reported in a publically accessible database known as the Toxics Release Inventory (TRI).

All information submitted pursuant to EPCRA regulations is publicly accessible, unless protected by a trade secret claim.

EPA's RCRA, Superfund and EPCRA Hotline, at (800) 535-0202, answers questions and distributes guidance regarding the emergency planning and community right-to-know regulations. Documents and resources can be obtained from the hotline's homepage at www.epa.gov/epaoswer/hotline. The EPCRA Hotline operates weekdays from 9:00 a.m. to 6:00 p.m., EST, excluding federal holidays.

Clean Air Act

The Clean Air Act (CAA) and its amendments are designed to "protect and enhance the nation's air resources so as to promote the public health and welfare and the productive capacity of the population." The CAA consists of six sections, known as Titles, which direct EPA to establish national standards for ambient air quality and for EPA and the states to implement, maintain, and enforce these standards through a variety of mechanisms. Under the CAA, many facilities are required to obtain operating permits that consolidate their air emission requirements. State and local governments oversee, manage, and enforce many of the requirements of the CAA. CAA regulations appear at 40 CFR Parts 50-99.

Pursuant to Title I of the CAA, EPA has established national ambient air quality standards (NAAQSs) to limit levels of "criteria pollutants," including carbon monoxide, lead, nitrogen dioxide, particulate matter, ozone, and sulfur dioxide. Geographic areas that meet NAAQSs for a given pollutant are designated as attainment areas; those that do not meet NAAQSs are designated as non-attainment areas. Under section110 and other provisions of the CAA, each state must develop a State Implementation Plan (SIP) to identify sources of air pollution and to determine what reductions are required to meet federal air quality standards. Revised NAAQSs for particulates and ozone were proposed in 1996 and will become effective in 2001.

Title I also authorizes EPA to establish New Source Performance Standards (NSPS), which are nationally uniform emission standards for new and modified stationary sources falling within particular industrial categories. NSPSs are based on the pollution control technology available to that category of industrial source (see 40 CFR Part 60).

Under Title I, EPA establishes and enforces National Emission Standards for Hazardous Air Pollutants (NESHAPs), nationally uniform standards oriented toward controlling specific hazardous air pollutants (HAPs). Section 112(c) of the CAA further directs EPA to develop a list of sources that emit any of 188 HAPs, and to develop regulations for these categories of sources. To date EPA has listed 185 source categories and developed a schedule for the establishment of emission standards. The emission standards are being developed for both new and existing sources based on "maximum achievable control technology" (MACT). The MACT is defined as the control technology achieving the maximum degree of reduction in the emission of the HAPs, taking into account cost and other factors.

Title II of the CAA pertains to mobile sources, such as cars, trucks, buses, and planes. Reformulated gasoline, automobile pollution control devices, and vapor recovery nozzles on gas pumps are a few of the mechanisms EPA uses to regulate mobile air emission sources.

Title IV-A establishes a sulfur dioxide and nitrogen oxides emissions program designed to reduce the formation of acid rain. Reduction of sulfur dioxide releases will be obtained by granting to certain sources limited emissions allowances that are set below previous levels of sulfur dioxide releases.

Title V of the CAA establishes an operating permit program for all "major sources" (and certain other sources) regulated under the CAA. One purpose of the operating permit is to include in a single document all air emissions requirements that apply to a given facility. States have developed the permit programs in accordance with guidance and regulations from EPA. Once a state program is approved by EPA, permits are issued and monitored by that state.

Title VI is intended to protect stratospheric ozone by phasing out the manufacture of ozone-depleting chemicals and restricting their use and distribution. Production of Class I substances, including 15 kinds of chlorofluorocarbons (CFCs), were phased out (except for essential uses) in 1996.

EPA's Clean Air Technology Center, at (919) 541-0800 or www.epa.gov/ttn/catc, provides general assistance and information on CAA standards. The Stratospheric Ozone Information Hotline, at (800) 296-1996 or www.epa.gov/ozone, provides general information about regulations promulgated under Title VI of the CAA; EPA's EPCRA Hotline, at (800) 535-0202 or www.epa.gov/epaoswer/hotline, answers questions about accidental release prevention under CAA section112(r); and information on air toxics can be accessed through the Unified Air Toxics website at www.epa.gov/ttn/uatw. In addition, the Clean Air Technology Center's website includes recent CAA rules, EPA guidance documents, and updates of EPA activities.

Federal Insecticide, Fungicide, and Rodenticide Act

The Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) was first passed in 1947, and amended numerous times, most recently by the Food Quality Protection Act (FQPA) of 1996. FIFRA provides EPA with the authority to oversee, among other things, the registration, distribution, sale and use of pesticides. The Act applies to all types of pesticides, including insecticides, herbicides, fungicides, rodenticides and antimicrobials. FIFRA covers both intrastate and interstate commerce.

<u>Establishment Registration</u>
Section 7 of FIFRA requires that establishments producing pesticides, or active ingredients used in producing a pesticide subject to FIFRA, register with EPA. Registered establishments must report the types and amounts of pesticides and active ingredients they produce. The Act also provides EPA inspection authority and enables the agency to take enforcement actions against facilities that are not in compliance with FIFRA.

<u>Product Registration</u>
Under section 3 of FIFRA, all pesticides (with few exceptions) sold or distributed in the U.S. must be registered by EPA. Pesticide registration is very specific and generally allows use of the product only as specified on the label. Each registration specifies the use site i.e., where the product may be used and the amount that may be applied. The person who seeks to register the pesticide must file an application for registration. The application process often requires either the citation or submission of extensive environmental, health and safety data.

To register a pesticide, the EPA Administrator must make a number of findings, one of which is that the pesticide, when used in accordance with widespread and commonly recognized practice, will not generally cause unreasonable adverse effects on the environment.

FIFRA defines "unreasonable adverse effects on the environment" as "(1) any unreasonable risk to man or the environment, taking into account the economic, social, and environmental costs and benefits of the use of the pesticide, or (2) a human dietary risk from residues that result from a use of a pesticide in or on any food inconsistent with the standard under section 408 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 346a)."

Under FIFRA section 6(a)(2), after a pesticide is registered, the registrant must also notify EPA of any additional facts and information concerning unreasonable adverse environmental effects of the pesticide. Also, if EPA determines that additional data are needed to support a registered pesticide, registrants may be requested to provide additional data. If EPA determines that the registrant(s) did not comply with their request for more information, the registration can be suspended under FIFRA section 3(c)(2)(B).

Use Restrictions

As a part of the pesticide registration, EPA must classify the product for general use, restricted use, or general for some uses and restricted for others (Miller, 1993). For pesticides that may cause unreasonable adverse effects on the environment, including injury to the applicator, EPA may require that the pesticide be applied either by or under the direct supervision of a certified applicator.

Reregistration

Due to concerns that much of the safety data underlying pesticide registrations becomes outdated and inadequate, in addition to providing that registrations be reviewed every 15 years, FIFRA requires EPA to reregister all pesticides that were registered prior to 1984 (section 4). After reviewing existing data, EPA may approve the reregistration, request additional data to support the registration, cancel, or suspend the pesticide.

Tolerances and Exemptions

A tolerance is the maximum amount of pesticide residue that can be on a raw product and still be considered safe. Before EPA can register a pesticide that is used on raw agricultural products, it must grant a tolerance or exemption from a tolerance (40 CFR Parts 163.10 through 163.12). Under the Federal Food, Drug, and Cosmetic Act (FFDCA), a raw agricultural product is deemed unsafe if it contains a pesticide residue, unless the residue is within the limits of a tolerance established by EPA or is exempt from the requirement.

Cancellation and Suspension

EPA can cancel a registration if it is determined that the pesticide or its labeling does not comply with the requirements of FIFRA or causes unreasonable adverse effects on the environment (Haugrud, 1993).

In cases where EPA believes that an "imminent hazard" would exist if a pesticide were to continue to be used through the cancellation proceedings, EPA may suspend the pesticide registration through an order and thereby halt the sale, distribution, and usage of the pesticide. An "imminent hazard" is defined as an unreasonable adverse effect on the environment or an unreasonable hazard to the survival of a threatened or endangered species that would be the likely result of allowing continued use of a pesticide during a cancellation process.

When EPA believes an emergency exists that does not permit a hearing to be held prior to suspending, EPA can issue an emergency order which makes the suspension immediately effective.

Imports and Exports

Under FIFRA section 17(a), pesticides not registered in the U.S. and intended solely for export are not required to be registered provided that the exporter obtains and submits to EPA, prior to export, a statement from the foreign purchaser acknowledging that the purchaser is aware that the product is not registered in the United States and cannot be sold for use there. EPA sends these statements to the government of the importing country. FIFRA sets forth additional requirements that must be met by pesticides intended solely for export. The enforcement policy for exports is codified at 40 CFR Parts 168.65, 168.75, and 168.85.

Under FIFRA section 17(c), imported pesticides and devices must comply with U.S. pesticide law. Except where exempted by regulation or statute, imported pesticides must be registered. FIFRA section 17(c) requires that EPA be notified of the arrival of imported pesticides and devices. This is accomplished through the Notice of Arrival (NOA) (EPA Form 3540-1), which is filled out by the importer prior to importation and submitted to the EPA regional office applicable to the intended port of entry. U.S. Customs regulations prohibit the importation of pesticides without a completed NOA. The EPA-reviewed and signed form is returned to the importer for presentation to U.S. Customs when the shipment arrives in the U.S. NOA forms can be obtained from contacts in the EPA Regional Offices or *www.epa.gov/oppfead1/international/noalist.htm*.

Additional information on FIFRA and the regulation of pesticides can be obtained from a variety of sources, including EPA's Office of Pesticide Programs www.epa.gov/pesticides, EPA's Office of Compliance, Agriculture and Ecosystem Division es.epa.gov/oeca/agecodiv.htm, or The National Agriculture Compliance Assistance Center, (888) 663-2155 or es.epa.gov/oeca/ag. Other sources include the National Pesticide Telecommunications Network, (800) 858-7378, and the National Antimicrobial Information Network, (800) 447-6349.

Toxic Substances Control Act

The Toxic Substances Control Act (TSCA) granted EPA authority to create a regulatory framework to collect data on chemicals in order to evaluate, assess, mitigate, and control risks which may be posed by their manufacture, processing, and use. TSCA provides a variety of control methods to prevent chemicals from posing unreasonable risk. It is important to note that pesticides as defined in FIFRA are not included in the definition of a "chemical substance" when manufactured, processed, or distributed in commerce for use as a pesticide.

TSCA standards may apply at any point during a chemical's life cycle. Under TSCA section 5, EPA has established an inventory of chemical substances. If a chemical is not already on the inventory, and has not been excluded by TSCA, a premanufacture notice (PMN) must be submitted to EPA prior to manufacture or import. The PMN must identify the chemical and provide available information on health and environmental effects. If available data are not sufficient to evaluate the chemical's effects, EPA can impose restrictions pending the development of information on its health and environmental effects. EPA can also restrict significant new uses of chemicals based upon factors such as the projected volume and use of the chemical.

Under TSCA section 6, EPA can ban the manufacture or distribution in commerce, limit the use, require labeling, or place other restrictions on chemicals that pose unreasonable risks. Among the chemicals EPA regulates under section 6 authority are asbestos, chlorofluorocarbons (CFCs), lead, and polychlorinated biphenyls (PCBs).

Under TSCA section 8(e), EPA requires the producers and importers (and others) of chemicals to report information on a chemicals' production, use, exposure, and risks. Companies producing and importing chemicals can be required to report unpublished health and safety studies on listed chemicals and to collect and record any allegations of adverse reactions or any information indicating that a substance may pose a substantial risk to humans or the environment.

EPA's TSCA Assistance Information Service, at (202) 554-1404, answers questions and distributes guidance pertaining to Toxic Substances Control Act standards. The Service operates from 8:30 a.m. through 4:30 p.m., EST, excluding federal holidays.

Coastal Zone Management Act

The Coastal Zone Management Act (CZMA) encourages states/tribes to preserve, protect, develop, and where possible, restore or enhance valuable natural coastal resources such as wetlands, floodplains, estuaries, beaches, dunes, barrier islands, and coral reefs, as well as the fish and wildlife using those habitats. It includes areas bordering the Atlantic, Pacific, and Arctic Oceans, Gulf of Mexico, Long Island Sound, and Great Lakes. A unique feature of this law is that participation by states/tribes is voluntary.

In the Coastal Zone Management Act Reauthorization Amendments (CZARA) of 1990, Congress identified nonpoint source pollution as a major factor in the continuing degradation of coastal waters. Congress also recognized that effective solutions to nonpoint source pollution could be implemented at the state/tribe and local levels. In CZARA, Congress added

Section 6217 (16 U.S.C. section 1455b), which calls upon states/tribes with federally-approved coastal zone management programs to develop and implement coastal nonpoint pollution control programs. The Section 6217 program is administered at the federal level jointly by EPA and the National Oceanic and Atmospheric Agency (NOAA).

Section 6217(g) called for EPA, in consultation with other agencies, to develop guidance on "management measures" for sources of nonpoint source pollution in coastal waters. Under Section 6217, EPA is responsible for developing technical guidance to assist states/tribes in designing coastal nonpoint pollution control programs. On January 19, 1993, EPA issued its *Guidance Specifying Management Measures For Sources of Nonpoint Pollution in Coastal Waters*, which addresses five major source categories of nonpoint pollution: (1) urban runoff, (2) agriculture runoff, (3) forestry runoff, (4) marinas and recreational boating, and (5) hydromodification.

Additional information on coastal zone management may be obtained from EPA's Office of Wetlands, Oceans, and Watersheds, www.epa.gov/owow, or from the Watershed Information Network www.epa.gov/win. The NOAA website, www.nos.noaa.gov/ocrm/czm/, also contains additional information on coastal zone management.

VI.B. Industry Specific Requirements

The onshore and offshore segments of the oil and gas extraction industry are subject to different sets of regulations. Onshore, releases primarily are under the authority of EPA. Federal land leases are managed by the Bureau of Land Management (BLM) in the Department of the Interior (DOI). States also impose regulations and play a crucial role in exploration and production solid waste regulation because of the RCRA exemption. Offshore, on the Outer Continental Shelf (OCS), the Minerals Management Service (MMS) of DOI is the designated regulatory agency. MMS oversees leasing operations and shares responsibility for environmental regulation with EPA.

Because of these differences, onshore and offshore regulations are discussed in separate sections. In addition, regulatory differences associated with stripper wells (wells that produce less than 10 barrels of oil per day) and selected state regulations are presented.

VI.B.1. Onshore Requirements

Laws Regulating Oil and Gas Exploration and Production on Federal Lands

Many regulations controlling the location of onshore oil and gas production stem from the Federal Land Policy and Management Act (FLPMA) of 1976. Production is barred at national monuments, national rivers, and areas of critical environmental concern. On Federal land where oil production is allowed, the Bureau of Land Management (BLM), under the Department of the Interior (DOI), is authorized under 43 CFR Parts 3160-92 to regulate the siting, drilling and production activities; an exception is on lands within the National Forest System, where BLM must obtain the consent of the Secretary of Agriculture. Oil and gas production regulation is achieved through the distribution of leases and the issuance of drilling permits. Most procedures are established under the Federal Oil and Gas Leasing Reform Act of 1987. Included in this Act are bonding regulations, presented in 43 CFR Part 3104, that require submission of a surety or personal bond to ensure compliance with requirements for the plugging of wells, reclamation of the leased areas, and restoration of any lands or surface waters adversely affected by lease operations. The BLM is revising its regulations. A proposed rule was promulgated in early 1999.

National Environmental Policy Act (NEPA)
NEPA requires that all Federal agencies prepare detailed statements assessing the environmental impact of, and alternatives to, major Federal actions that may "significantly affect" the environment. An environmental impact statement (EIS) must provide a fair and full discussion of significant environmental impacts and inform both decision-makers and the public about

the reasonable alternatives that would avoid or minimize adverse impacts on the environment; EISs must explore and evaluate all reasonable alternatives, even if they are not within the authority of the lead agency. NEPA authorities are solely procedural; NEPA cannot compel selection of the environmentally preferred alternative. For offshore operations new sources require NEPA analysis.

Federal actions specifically related to oil and gas exploration and production that may require EISs include Federal land management agency (e.g., BLM and Forest Service) approval of plans of operations for exploration or production on Federally-managed lands. All affected media (e.g., air, water, soil, geologic, cultural, economic resources, etc.) must be addressed. The EIS provides the basis for the permit decision; for example, an NPDES permit may be issued or denied based on EPA's review of the overall impacts, not just discharge-related impacts, of the proposed project and alternatives. Issues may include the potential for surface or groundwater contamination, aquatic and terrestrial habitat value and losses, sediment production, mitigation, and reclamation.

Clean Air Act (CAA)

The oil and gas production industry is subject to recently-promulgated National Emission Standards for Hazardous Air Pollutants (NESHAP) (Federal Register, Vol. 64, No. 116, June 17, 1999). The regulation calls for the application of maximum achievable control technology (MACT) in order to reduce the emissions of hazardous air pollutants (HAP) at facilities classified as major sources. The primary HAPs released by the industry are benzene, toluene, ethyl benzene, and mixed xylenes (BTEX) and n-heptane. The technology requirements involve the following emission points: process vents on glycol dehydration units, storage vessels with flash emissions, and equipment leaks at natural gas processing plants. Additional requirements include the installation of air emission control devices, and adherence to test methods and procedures, monitoring and inspection requirements, and recordkeeping and reporting requirements.

In addition, New Source Performance Standards (NSPS) may affect exploration and production facilities. Standards apply to devices used at these facilities, including gas turbines, steam generators, storage vessels for petroleum liquids, volatile organic liquid storage vessels, and gas processing plants (see 40 CFR Part 60). Requirements will depend on whether the region in which the particular facility is located is in compliance with the National Ambient Air Quality Standards (NAAQS) and whether Prevention of Significant Deterioration (PSD) requirements apply (EPA, 1992).

Clean Water Act

Onshore exploration and production facilities may be subject to four aspects of the CWA: national effluent limitation guidelines, stormwater regulations, and wetlands regulations, and Spill Prevention Control and Countermeasure (SPCC) requirements.

National effluent limitation guidelines have been issued for two subcategories of onshore (non-stripper) wells. The Onshore Subcategory guidelines prohibit the discharge of water pollutants from any source associated with production, field exploration, drilling, well completion, or well treatment (40 CFR Part 435.30). Agriculture and Wildlife Water Use Subcategory guidelines apply to facilities in the continental United States west of the 98th meridian for which produced water may be used beneficially for irrigation or wildlife propagation. For facilities in this subcategory, produced water may be discharged into navigable waters so long as it does not exceed limitations for oil and grease, and is put to use for agricultural purposes. Discharge of waste pollutants excluding produced water is prohibited (40 CFR Part 435.50).

Oil and gas exploration and production facilities are exempt from CWA stormwater Phase I regulations under most conditions, but there are two exceptions: (1) if the facility has a reportable quantity spill that could be carried to waters of the United States via a storm event, or (2) if the stormwater runoff violates a water quality standard. (See 40 CFR Parts 117 and/or 302 for reportable quantities of hazardous substances or Part 110 for the reportable quantity of spilled oil.) If either of these two scenarios should happen, the facility would be required to apply for a Multi-Sector General Permit (MSGP) stormwater permit and develop a pollution prevention plan. However, if a reportable quantity spill were to be cleaned up quickly or containment were so total that there would be no threat of a product release as a result of storm water event, there would be no permit requirement. In addition, coverage is mandatory under the Construction General Permit (CGP) for earth-disturbing activities of five acres or more. This is relevant during exploration or site expansion efforts (EPA Region VI Stormwater Hotline, 1999; Rittenhouse, 1999). See Section VI.C. for proposed Phase II regulations that may impact the industry.

<u>Wetlands</u>
During the course of petroleum exploration wetlands may be encountered. Under the CWA wetlands are defined by the frequency and length of time they are saturated with water, by the type of vegetation they support, and by soil characteristics. Also by definition wetlands are part of the "waters of the United States" and as such all discharges of pollutants to wetlands require a CWA permit. However, the CWA regulates not only the discharges of dissolved pollutants but also the discharge of solids, dredge and fill materials

or dirt to waters of the United States. Permits are required for the filling of wetlands (dredging is regulated under the 1899 Rivers and Harbors Act). Permits are of two types: general (a standard permit for certain classes of activities) or site-specific.

Enforcement of the CWA provisions for wetlands is overseen by the Army Corps of Engineers, EPA and in some cases the States. Most of the day to day administration of the program is implemented by the Corps of Engineers (COE). The COE issues and enforces permits, and is also responsible for delineating wetlands. EPA regions comment on permits and can enforce the provisions of the Act. EPA also helps to develop environmental criteria for wetlands. The COE can approve a state to operate the CWA wetlands program (only Maryland and New Jersey are currently approved). If a state is authorized to operate the CWA wetlands program it may issue a permit in addition to the COE issued permit. Any state can comment on wetland permits prior to issuance.

<u>Spill Prevention Control and Countermeasure Plans</u>

An oil and gas production, drilling, or workover facility will be subject to Spill Prevention Control and Countermeasure (SPCC) requirements if it meets the following specifications: the facility could reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines, and have (1) a total underground buried storage capacity of more than 42,000 gallons; (2) a total aboveground oil storage capacity of more than 1,320 gallons; or (3) an aboveground oil storage capacity of more than 660 gallons in a single container. SPCC applicability is dependent on the tank's maximum design storage volume and not "safe" operating or other lesser operational volumes. For purposes of the regulation, an onshore production facility may include all wells, flowlines, separation equipment, storage facilities, gathering lines, and auxiliary non-transportation-related equipment and facilities in a single geographical oil or gas field operated by a single operator.

All facilities subject to SPCC requirements must prepare a site-specific spill prevention plan that incorporates requirements specified in 40 CFR Part 112.7. For production facilities, these include considerations for the following processes and procedures:

- Drainage
- Tank materials
- Secondary containment
- Visual inspection of tanks
- Fail-safe engineering methods for tank battery installations
- Tank repair and maintenance
- Facility transfer operations

- Inspection and testing measures
- Record-keeping
- Security
- Personnel training.

In addition, the plan must discuss spill history and spill prediction (i.e., the anticipated direction of flow). The SPCC plan must be approved by a Registered Professional Engineer who is familiar with SPCC requirements, be fully implemented, and be modified when changes are made to the facility (e.g., installation of a new tank). Regardless of whether changes have been made to the facility, the plan must be reviewed at least once every three years, and amended if new, field-proven technology may reduce the likelihood of a spill.

The SPCC plan must also address oil drilling and workover facility equipment. This portion of the plan requires that the equipment be positioned or located so as to prevent spilled oil from reaching navigable waters, that catchment basins or diversionary structures be in place, and that blowout preventers (BOPs) are installed according to state regulatory requirements.

A portion of SPCC-regulated facilities may also be subject to Facility Response Planning (FRP) requirements if they pose a threat of "substantial harm" to navigable waters. The determination of a "substantial harm" facility is made on the basis of meeting either of two sets of criteria – one involving transfer over water, and the other involving oil storage capacity or other factors. If the facility were subject to FRP requirements, it would be required to develop a facility response plan which would involve, among other requirements, identification of small, medium and worst-case discharge scenarios and response actions; a description of discharge detection procedures and equipment; detailed implementation plans for containment and disposal; diagrams of facility and surrounding layout, topography, and evacuation paths; and employee training, exercises, and drills.

Safe Drinking Water Act (SDWA)

The Underground Injection Control (UIC) program of the SDWA regulates injection wells used in the oil and gas production process for produced water disposal or for enhanced recovery. Wells used in this industry for produced water are classified as Class II. Minimum UIC Class II well requirements, as outlined in 40 CFR Part 144, involve specific construction, operation, and closure standards, as well as provisions for ensuring that the owner, operator and/or transferor of the well maintain financial responsibility and resources to plug and abandon the well. Included are casing and cementing requirements based on the depth to the injection zone, location of aquifers, and estimated injection pressures as well as other possible considerations. Operational standards involve regular (at least once every five years) mechanical integrity tests (MITs); monitoring of injection pressure, flow rate, and volume; monitoring of the nature of injected fluid as needed; and annual reporting of monitoring results. Finally, closure procedures must be performed in accordance with an approved plugging and abandonment plan, which includes the placement and composition of cement plugs, the amount of casing to be left in the hole, the estimated cost of plugging, and any proposed tests or measurements. Additional requirements may be imposed in states that have been delegated implementation of the UIC program.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

The "petroleum exclusion" is an important exemption under CERCLA requirements for the oil and gas extraction industry. Under the "hazardous substance" definition, "petroleum, including crude oil or any fraction thereof," is exempted unless specifically listed or designated under CERCLA (CERCLA section 101 (14)). Subsequent interpretation has concluded that listed hazardous substances that are normally found in crude oil, such as benzene, do not invalidate the exemption unless the concentration of these substances is increased by contamination or by addition after refining. However, specifically listed waste oils (e.g., F010, and K042 through K048) are subject to reporting requirements if spilled in excess of their established Reportable Quantities (RQs) (EPA, 1998).

Emergency Planning and Community Right-to-Know Act (EPCRA)

The oil and gas extraction industry is currently not required to report to TRI under EPCRA section 313, which requires facilities under certain SIC codes to submit annual reports of toxic chemical releases to the Toxic Release Inventory (TRI). (Please see Section VI.C., Pending and Proposed Regulatory Requirements, of this document, however, for possible future changes to this status.) However, oil and gas extraction facilities are generally responsible for other reporting obligations of EPCRA if the facility stores or manages threshold levels of specified chemicals.

Resource Conservation and Recovery Act (RCRA)

Under the 1980 Amendments to RCRA, Congress conditionally exempted certain categories of solid waste from regulation as hazardous wastes under RCRA Subtitle C including drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas. The Amendments required EPA to study these wastes to determine whether their regulation as hazardous wastes was warranted and to submit a report to Congress. In its report to Congress and in a July 1988 regulatory determination (53 FR 25446, July 6, 1988), the Agency stated that regulation as hazardous wastes under Subtitle C was not warranted and that these wastes could be controlled under other federal and state regulatory programs including a tailored RCRA Subtitle D program.

Specifically, EPA's regulatory determination for exploration and production (E&P) wastes found that the following wastes are exempt from RCRA hazardous waste management requirements. The list below identifies many, but not all, exempt wastes. In general, E&P exempt wastes are generated in "primary field operations," and not as a result of maintenance or transportation activities. Exempt wastes are typically limited to those that are intrinsically related to the production of oil or natural gas.

- Produced water;
- Drilling fluids;
- Drill cuttings;
- Rigwash;
- Drilling fluids and cuttings from offshore operations disposed of onshore;
- Well completion, treatment, and stimulation fluids;
- Basic sediment and water, and other tank bottoms from storage facilities that hold product and exempt waste;
- Accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments;
- Pit sludges and contaminated bottoms from storage or disposal of exempt wastes;
- Workover wastes;
- Gas plant sweetening wastes for sulfur removal, including amine, amine filters, amine filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge;
- Cooling tower blowdown;
- Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream);
- Packing fluids;
- Produced sand;
- Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation;
- Hydrocarbon-bearing soil;
- Pigging wastes from gathering lines;
- Wastes from subsurface gas storage and retrieval, except for the listed non-exempt wastes;
- Constituents removed from produced water before it is injected or otherwise disposed of;
- Liquid hydrocarbons removed from the production stream but not from oil refining;

- Gases removed from the production stream, such as hydrogen sulfide and carbon dioxide, and volatilized hydrocarbons;
- Materials ejected from a producing well during the process known as blowdown;
- Waste crude oil from primary field operations and production; and
- Light organics volatilized from exempt wastes in reserve pits or impoundments or production equipment.

On March 22, 1993, EPA provided "clarification" regarding the scope of the E&P waste exemption for waste streams generated by crude oil and tank bottom reclaimers, oil and gas service companies, crude oil pipelines, and gas processing plants and their associated field gathering lines. (See 58 FR 15284-15287.) EPA stated that certain waste streams from these operations are "uniquely associated" with primary field operations and as such are within the scope of the RCRA Subtitle C exemption. EPA's clarification cautioned, however, that these wastes may not be exempt if they are mixed with non-exempt materials or wastes.

EPA's 1988 regulatory determination lists the following wastes as non-exempt. The list below identifies many, but not all non-exempt wastes, as well as transportation (pipeline and trucking) activities. While the following wastes are non-exempt, their regulatory status as "hazardous wastes" is dependent upon a determination of their characteristics or whether they are specifically listed as RCRA hazardous waste.

- Unused fracturing fluids or acids;
- Gas plant cooling tower cleaning wastes;
- Painting wastes;
- Oil and gas service company wastes, such as empty drums, drum rinsate, vacuum truck rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids;
- Vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste;
- Refinery wastes;
- Liquid and solid wastes generated by crude oil and tank bottom reclaimers;
- Used equipment lubrication oils;
- Waste compressor oil, filters, and blowdown;
- Used hydraulic fluids;
- Waste solvents;
- Waste in transportation pipeline-related pits;
- Caustic or acid cleaners;
- Boiler cleaning wastes;
- Boiler refractory bricks;
- Incinerator ash;

- Laboratory wastes;
- Sanitary wastes;
- Pesticide wastes;
- Radioactive tracer wastes; and
- Drums, insulation, and miscellaneous solids.

EPA did not specifically address, in its 1988 regulatory determination, the status of hydrocarbon-bearing material that is recycled or reclaimed by reinjection into a crude stream. However, under existing EPA regulations, recycled oil, even if it were otherwise hazardous, could be reintroduced into the crude stream, if it is from normal operations and is to be refined along with normal process streams at a petroleum refinery facility (40 CFR Part 261.6 (a)(3)(vi).)

The Agency also determined that produced water injected for enhanced recovery is not a waste for purposes of RCRA regulation and therefore is not subject to control under RCRA Subtitle C or Subtitle D. Produced water used in this manner is considered beneficially recycled and is an integral part of some crude oil and natural gas production processes. Produced water injected in this manner is already regulated by the Underground Injection Control program under the SDWA. However, if produced water is stored in surface impoundments prior to injection, it may be subject to RCRA Subtitle D regulations.

It is important to note that some states have adopted hazardous waste regulations which differ from those that EPA has promulgated. While different in many specific areas, those state programs, by law, still must be at least as stringent as the federal programs.

Endangered Species Act (ESA)

The ESA provides a means to protect threatened or endangered species and the ecosystems that support them. It requires Federal agencies to ensure that activities undertaken on either Federal or non-Federal property do not have adverse impacts on threatened or endangered species or their habitat. In a 1995 ruling, the U.S. Supreme Court upheld interpretations of the Act that allow agencies to consider impact on habitat as a potential form of prohibited "harm" to endangered species. Agencies undertaking a Federal action (such as a BLM or MMS review of proposed oil and gas extraction production operations) must consult with the U.S. Fish and Wildlife Service, and an EIS must be prepared if "any major part of a new source will have significant adverse effect on the habitat" of a Federally- or State-listed threatened or endangered species.

VI.B.2. Offshore Requirements

This section describes laws and regulations applying to offshore production facilities that differ from those presented above for onshore facilities. It should be noted that several regulations presented in the onshore section will apply to offshore sites as well. Offshore facilities are: 1) those which are found within the Federal jurisdiction of the Outer Continental Shelf and are operated under Minerals Management Service (MMS) leases, and 2) those that are found in territorial seas and are operated under state leases. Facilities in the territorial seas are operated under both state and federal regulations and therefore some regulations discussed below may not be applicable. In addition, coastal facilities, which are generally landward of the inner boundary of the territorial seas (approximated by the shoreline) are operated under state regulations and therefore some regulations discussed below may not be applicable.

Offshore Jurisdictions

The Outer Continental Shelf (OCS) consists of the submerged lands, subsoil, and seabed, lying between the seaward extent of the states' jurisdiction and the seaward extent of federal jurisdiction. The continental shelf is the gently sloping undersea plain between a continent and the deep ocean. The United States OCS has been divided into four leasing regions. They are the Gulf of Mexico Region, the Atlantic OCS Region, the Pacific OCS Region, and the Alaska OCS Region. State jurisdiction is defined as follows. Texas and the Gulf Coast of Florida are extended 3 marine leagues (approximately 9 nautical miles) seaward from the baseline from which the breadth of the territorial sea is measured. Louisiana is extended 3 imperial nautical miles (imperial nautical miles are 6,080.2 feet) seaward of the baseline from which the breadth of the territorial sea is measured. All other states' seaward limits are extended 3 nautical miles (approximately 3.3 statute miles) seaward of the baseline from which the breadth of the territorial sea is measured. Federal jurisdiction is defined under accepted principals of international law. The seaward limit is defined as the farthest of 200 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured.

Outer Continental Shelf Lands Act (OSCLA)

OCSLA establishes Federal jurisdiction over submerged lands on the Outer Continental Shelf (OCS) and requires the Secretary of the Interior to administer mineral leasing, exploration, and development on the OCS. Under the Act, leases are granted to the highest qualified responsible bidder(s), on the basis of sealed competitive bids. Objectives of the OCSLA include allowing for expeditious and orderly development of OCS resources, encouraging the development of new technology to minimize the likelihood of accidents or events that might damage the environment or endanger life or health, and ensuring that a State's regulatory protection for land, air, and water uses are considered within its jurisdiction (MMS, 1999; National Research Council, 1996).

In offshore locations, the production is limited under Title III of the Marine Protection, Research, and Sanctuaries Act (MPRSA), which provides for the designation of sanctuaries for areas of conservation, recreational, ecological, or aesthetic value. The Marine Mammal Protection Act (MMPA) and the Endangered Species Act (ESA) prohibit the taking of species, and can also limit the placement of offshore wells.

Clean Air Act

In offshore areas, both the CAA and regulations of the MMS govern air quality. Coastal areas and the offshore regions of the Pacific, Atlantic, and Arctic Oceans, as well as the region of the Gulf of Mexico adjacent to Florida, are subject to the CAA. Important regulations include the NESHAP and NSPS standards described above for onshore facilities.

The sections of the Gulf of Mexico adjacent to Texas, Louisiana, Mississippi, and Alabama are exempt from the 1990 CAA amendments, and instead must adhere to MMS air quality standards. These standards set limits for VOC, CO, NO_2, SO_2, and Total Suspended Particulate (TSP) pollutants, and require limits for sources that significantly affect the quality of a nonattainment area (30 CFR Part 250.45).

Additional MMS air regulations apply to offshore sites. Blowout prevention regulations (in the form of safety practices and equipment requirements) attempt to reduce accidental releases. The venting and flaring of natural gas is limited under MMS rules so that natural gas may be released only when required for safety or when the volume is small (Sustainable Environmental Law and 30 CFR Part 250.175).

Clean Water Act

In offshore locations, facilities must acquire National Pollutant Discharge Elimination System (NPDES) permits before any pollutant can be discharged from a point source in U.S. waters. Standards differ for the offshore and coastal subcategories. For offshore facilities, permits require the use of best available technology economically achievable (BAT) or best conventional pollutant control technology (BCT). Discharges from coastal facilities, which are landward of the inner boundary of the territorial seas, are mostly prohibited (Jordan, 1998; note that the definition of the coastal category for the purposes of the CWA is different than that for mineral rights, presented in Section II). An exception to the coastal discharge prohibition is for facilities in Cook Inlet, Alaska, where discharges may be made in accordance with BPT, BAT, or BCT effluent limitations.

Facilities located offshore of EPA Region 6 (and some in Regions 9 and 10) are subject to a general CWA permit that covers all facilities in certain geographic locations. Offshore exploration and production facilities in Regions 4, 9 and 10 are also permitted individually in some cases. EPA Regions 6 and 9 have an MOA with MMS whereby MMS agrees to conduct CWA preliminary inspections for EPA.

In addition to NPDES permitting requirements, offshore facilities may be subject to CWA Section 403. This section is intended to ensure that no unreasonable degradation of the marine environment occurs as a result of permitted discharges, and to ensure that sensitive ecological communities are protected. Requirements may involve ambient monitoring programs to determine degradation of marine waters, alternative assessments designed to further evaluate the consequences of various disposal options, and pollution prevention techniques designed to further reduce the quantities of pollutants requiring disposal and thereby reduce the potential for harm to the marine environment. If section 403 requirements for protection of the ecological health of marine waters are not met, an NPDES permit will not be issued.

Spill Prevention Control and Countermeasure Plans

Many aspects of SPCC rule described above for onshore facilities apply to offshore facilities as well. 40 CFR Part 112.7(e)(7) provides additional spill prevention and control measures to be addressed in SPCC plans for offshore facilities. These include:

- Oil drainage collection equipment around pumps, joints, valves, separators, tanks, etc.
- Adequately-sized sump systems
- Dump valves installed with oil-water separators and treaters
- High-level sensing devices for atmospheric storage tanks and corrosion protection for all tanks
- High pressure sensing device and shut-in valve for pipelines appurtenant to the facility.

Oil Spill Contingency Plans

Pursuant to 30 CFR 250.203, 250.204 and 254, a lessee is required to submit an Oil Spill Contingency Plan (OSCP) to MMS for approval. This plan identifies the response capabilities of lease and pipeline operators in the event an accidental oil spill occurs during drilling or production activities.

Additionally, the Oil Pollution Act of 1990 authorizes the MMS to require Oil Spill Contingency Plans from oil and gas lessees operating in state waters seaward of the coastline. Operators must join a cooperative with oil spill equipment available to members, or obtain a letter of agreement for rental of oil spill equipment. Oil Spill Coordinators must be trained. The entire Oil Spill Response Team must attend annual drills. The Plan requires annual review and update.

VI.B.3. Stripper Well Requirements

Stripper wells are identified as an individual subcategory in Clean Water Act NPDES requirements. In addition, stripper wells may be exempt from requirements under other statutes or regulations by virtue of their low production volume. For example, they may not meet the threshold of a major source of HAP for NESHAP requirements, or they may have less than the specified storage volume for SPCC rules. States and Federal agencies may also provide incentives to stripper well operators to maximize the number of these marginally profitable wells that remain operational. Reductions of severance taxes are available in some states, and BLM offers royalty rate reductions for qualifying stripper wells (Williams and Meyers, 1997; 43 CFR Part 3103.4-2).

Clean Water Act

Stripper wells are defined as onshore wells that produce less than 10 barrels of oil per day, are operating at the maximum feasible rate of production, and operate in accordance with recognized conservation practices (40 CFR Part 435.60) They are currently exempt from onshore point source discharge restrictions discussed above in Section VI.B.1. As a result, technology-based limitations instead are developed on a case-by-case basis or in a state-wide general permit.

VI.B.4. State Statutes

In addition to the federal laws described above, most oil-producing states develop other laws affecting oil and gas extraction and production. These include permitting, bonding, temporary abandonment, and plans for plugging orphan wells. Each oil-producing state has a regulatory body, and most require operators to obtain a well permit before drilling. Historically, permitting has been required in these places in order to ensure an efficient and safe mechanism for withdrawing oil from reservoirs by preventing wells from being drilled too close together (Williams and Meyers, 1997).

Nearly all oil-producing states require some form of security or financial assurance for those operators seeking a permit, in order to ensure proper plugging and abandonment. The form of assurance varies from state to state, but the most commonly accepted are surety bonds, certificates of deposit, and cash. The amount of money required for security can vary as well; the amounts range from $10,000 in Kentucky and Tennessee to a minimum of $200,000 in Alaska (IOGCC, 1996).

Laws for temporary abandonment of wells differ among states. (See Section III.B. for a discussion of temporary abandonment.) In general, States are reluctant to require plugging of wells that have significant potential for oil production (and state revenues), yet they seek to avoid problems associated with inactive and unattended wells. As a result, most states require inactive wells to gain state approval for temporary abandonment. (The term temporary abandonment is used for wells that are inactive with state approval.) Most states allow some period of time of inactivity (usually six months to one year) without approval. At this point, however, states may require a statement of future use from the operator; this statement might include extensive geological and engineering information and a schedule for returning the well to production. As part of a temporary abandonment permit, a state may require periodical mechanical integrity tests (MITs) to ensure that the temporarily abandoned well does not pose a threat to the environment (IOGCC, 1996).

Finally, many states have established plugging funds to ensure that wells that pose a threat to the environment but are without financial assurance are properly plugged. These wells, often called orphan wells (see Section III.C.), are identified and prioritized by any number of methods, and are plugged as funds become available and procurement issues are settled. Funding sources vary among states; in some states, such as Arkansas, California, and Mississippi, funding comes directly from the government's general fund or from the regulatory body's budget, while in others the programs are funded through permit fees, portions of oil taxes, bond forfeitures, or penalties (IOGCC, 1996).

In 1990, the Interstate Oil and Gas Compact Commission (IOGCC) developed guidelines for state oil and gas exploration and production waste management program. In 1991, IOGCC began reviewing state programs against the guidelines. State reviews were conducted by stakeholder teams. Review teams wrote reports of their findings, including strengths and weaknesses, and made recommendations for program improvements. Seventeen state programs were reviewed between 1991 and 1997. These reports are an excellent source of state-specific regulations and programs. State reviews can be obtained from IOGCC by calling (405) 525-3556 and from the IOGCC Website at *www.iogcc.oklaosf.state.ok.us/.* The state review program has subsequently been managed by STRONGER, Inc., a non-profit corporation.

For more information on IOGCC and STRONGER, Inc., see Section VIII.A.2., State Activities.

VI.C. Pending and Proposed Regulatory Requirements

Clean Water Act (CWA)

Proposed Phase II NPDES Storm Water Regulations

Under this proposal, construction sites between one and five acres would be regulated under the NPDES storm water program. The oil and gas exploration and production industry might be impacted by this rule during onshore drilling site preparations. Possible requirements include: the submission of a Notice of Intent (NOI) that would include general information and a certification that the activity will not impact endangered or threatened species, development and implementation of a Storm Water Pollution Prevention Plan (SWPPP) and use of best management practices (BMP) to minimize the discharge of pollutants from the site, and submission of a Notice of Termination (NOT) when final stabilization of the site has been achieved as defined in the permit. Finalization of the rule is anticipated in November 1999 (George Utting, EPA, Office of Water, (202) 260-9530 or John Kosco, EPA, Office of Water, (202) 260-6385).

Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids

This proposed rule would amend the technology-based effluent limitations guidelines and standards for the discharge of pollutants from oil and gas drilling operations associated with the use of synthetic-based drilling fluids (SBFs) and other non-aqueous drilling fluids into the waters of the United States. This proposed rule would apply to existing and new facilities in the offshore subcategory and the Cook Inlet portion of the coastal subcategory of the oil and gas extraction point source category. The final rule is scheduled for December 2000. (Carey A. Johnston, EPA, Office of Water, (202) 260-7186).

Revisions to the Oil Pollution Prevention Regulation

Three separate proposals, in 1991, 1993, and 1997, had been offered to amend the text of 40 CFR Part 112, which includes requirements for sites to develop spill prevention control and countermeasures (SPCC) plans. The current proposed rule is a consolidation of the three proposals. The goals of the new rule are to give more flexibility with paperwork and to reduce the burden of information collection for some facilities. Two considerations will be emphasized during the rule development: the importance of good engineering practices and the value of site-specific flexibility. A final rule is expected during Spring, 2000. (Hugo Fleischman, EPA, Office of Solid Waste and Emergency Response, (703) 603-8769).

Emergency Planning and Community Right-To-Know Act (EPCRA)

Addition of Oil and Gas Exploration and Production to the Toxic Release Inventory

A long-term consideration is the addition of the oil and gas extraction industry to regulation under EPCRA section 313, which requires reporting to the Toxics Release Inventory (TRI). The possible addition of the industry was considered carefully in 1996, but was not added at that time. The proposal may enter the proposed rule stage in December, 2000, but no definite schedule had been set at the time of the publication of this document. (Tim Crawford, EPA, Office of Prevention, Pesticides, and Toxic Substances, (202) 260-1715).