CHAPTER IV

REGULATORY PROGRAMS AND RECOMMENDED INDUSTRY PROCEDURES

INTRODUCTION

This chapter identifies and reviews the current State and Federal regulatory programs and industry-recommended procedures applicable to either reduce the potential for routine emissions and/or accidental hydrogen sulfide releases from oil and gas production or to mitigate the consequences of such emissions and releases.

STATE REGULATIONS

Currently, there are no national ambient air quality standards (NAAQS) for H_2S. Most oil- and gas-producing States have their own regulations pertaining to H_2S gas. Table IV-1 lists States that have set ambient air quality standards for H_2S emissions.

The EPA gathered and reviewed several States' regulations and related guidance documents and later contacted State agencies to obtain additional information on the unique aspects of the State regulations governing H_2S emissions in the oil and gas industry. EPA staff also met with officials from North Dakota during a trip to North Dakota oil and gas well sites. In addition, the Interstate Oil and Gas Compact Commission (IOGCC) was contacted to obtain information pertaining to regulatory programs (IOGCC, 1990).

This chapter contains a review of existing State regulations for nine States (California, Louisiana, Michigan, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming).

These nine States were chosen for review because of their large production volumes, the potential presence of H_2S in their well fields, and their distribution across the United States. The nine States contain over 68 percent of the total oil wells (419,989 wells/613,810 total U.S. wells) and 54 percent of the gas wells (147,360 wells/272,541 total U.S. wells) producing in the United States in 1991 (Petroleum Independent, 1992). For these States, regulatory agencies are identified, H_2S regulations for routine emissions and accidental releases are described, enforcement programs are discussed, records and programs to track accidental H_2S release are included, and the effectiveness of each State program is assessed qualitatively. The qualitative evaluation identifies existing control standards and the populations or ecosystems the standard is intended to protect.

In addition, these States account for 67 percent of the total U.S. oil production and 87 percent of the total U.S. natural gas production (Petroleum Independent, 1992). State regulations for H_2S emissions from the oil and gas industry in Oklahoma, Texas, Michigan,

Table IV-1. Ambient Air Quality Standards for H_2S

State	Concentration (ppb)	Average Time (hours)
California	30	1
Connecticut	200	8
Kentucky	10	1
Massachusetts	14	24
Minnesota	50[a]	0.5
	30[b]	0.5
Missouri	500[a]	0.5
	30[b]	0.5
Montana	50[c]	1
Nevada	240	8
New York	10	1
North Dakota	200[d]	1
	100[c]	24
Oklahoma	100	0.5
Pennsylvania	100	1
Rhode Island	10	1
Texas	80	0.5
Virginia	160	24
Hawaii	40	1
Delaware	30	1
Indiana	50	1

[a] Not to be exceeded more than two times/year.
[b] Not to be exceeded more than two times/five consecutive days.
[c] Not to be exceeded more than one time/year.
[d] Not to be exceeded more than one time/month.

and California were reviewed in greatest detail because they are major oil and gas producing States. These states have extensive regulations dealing with H_2S in the oil and gas industry. California's air quality program is managed by 33 independent air pollution control districts and its Division of Oil and Gas is divided into 6 districts where District heads have great flexibility in enforcing rules. Therefore, California's program is discussed in the greatest detail.

Selected Oil and Gas Producing States

Oklahoma

The H_2S regulations for Oklahoma (10.3.16, "Operation of Hydrogen Sulfide Areas") were listed in *Guidelines for Petroleum Emergency Field Situations in the State of Oklahoma*, a guidance manual that expands on the regulations. The guidance manual contains sections on characteristics and effects of H_2S, recommended guidelines for safe drilling and production operations in an H_2S environment.

The following agencies regulate oil and gas activities in Oklahoma:

- Oklahoma Corporation Commission (OCC), Oil and Gas Conservation Division
- Oklahoma Air Quality Service
- Osage Indian Tribe (OIT)
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The OCC has jurisdiction over laws and regulations "relating to the conservation of oil and gas and the prevention of pollution in connection with the exploration, drilling, producing, transporting, purchasing, processing and storage of oil and gas..." (OCC, 1986). The OIT has sole jurisdiction regarding oil and gas operations in Osage County. The U.S. Bureau of Land Management has responsibility for cases where both surface and mineral rights are owned by the Bureau or by an Indian tribe other than the Osage Tribe.

As noted earlier in this chapter, Oklahoma has an H_2S ambient air quality standard. This regulatory program (administered by the Air Quality Service) is used to control routine emissions (through permit) from oil and gas facilities.

The accidental release of H_2S from facilities is regulated by the OCC. Rule 165:10-3-16 of the OCC rules requires operators to assess their facilities for H_2S release potentials that would cause harm to the public. The rule is applicable to all facilities that handle natural gas containing 1×10^5 ppb H_2S or more and have a significant radius of exposure to cause adverse effects on the public with the exception of storage tanks. The "radius of exposure" is that distance from a source where the ground level concentration of hydrogen sulfide resulting from a release of gas from a facility is 1×10^5 ppb or 5×10^5 ppb whichever is applicable in the Rule. The Rule applies as follows:

- Does the facility (drilling, producing, injection, storage, etc.) handle hydrocarbon fluids containing 1×10^5 ppb H_2S or more? If yes;

- Determine the 1×10^5 ppb radius of exposure using an equation required in the Rule or other methods approved by the Commission. The H_2S escape rate from the facility must be determined as required by the Rule.

- If the 1×10^5 ppb radius of exposure is in excess of 50 feet, warning, marker and security provisions must be provided at the facility.

- If the 1×10^5 ppb radius of exposure is in excess of 50 feet and includes a public area or if the 5×10^5 ppb radius of exposure is in excess of 50 feet and includes a public road or if the 1×10^5 ppb radius of exposure is in excess of 3000 feet, control and safety equipment and a contingency plan must be provided for the facility.

- Facility storage tanks near atmospheric pressure containing 5×10^5 ppb or greater H_2S must have warning signs, wind indicators and possible fencing. Radius of exposure calculations are not applicable to storage tanks.

- H_2S training, injection or flaring provisions, accident notification and other requirements are addressed in the Rule (personal communication, W. Freeman, Shell Oil, 6/23/93).

The OCC does not keep an emissions inventory of accidental H_2S releases, but it does keep an inventory of wells with actual or potential H_2S problems. Furthermore, an inventory of inspection data is kept by individual inspectors in the State and the local field offices. Any emissions of H_2S exceeding the OCC standard of 2.5×10^4 ppb must be reported to the OCC by the emitting facility. Rule 3-2032, H_2S Operation, is intended to provide for the protection of the public's safety in areas where H_2S concentrations greater than 1×10^5 ppb may be encountered.

Drilling facilities are not required to submit data periodically to show that they are in compliance with regulations. Facilities report release of H_2S on an "honor system" once permits are granted. When noncompliance is discovered, the OCC can use administrative proceedings to shut down or fine the operation. However, in recent years, there has been no evidence of noncompliance with the H_2S regulations.

The OCC lists training requirements for employees who will work in areas of potential H_2S exposure. The training must cover hazards and characteristics of H_2S, operation of safety and life support systems, and emergency response procedures. OCC safety inspectors attend annual industry-sponsored training programs in order to stay current on safety developments and to check the safety of their breathing equipment. Each H_2S inspector is required to have an H_2S monitor, a manual, H_2S gas monitoring test tubes, and a self-contained air breathing apparatus. Specific H_2S provisions also exist regarding H_2S detection and alarm equipment, accident notification, injection, and flaring. In 1991, the OCC and the industry jointly sponsored an H_2S safety seminar. A film about H_2S safety was presented to regulatory and industry personnel, and questions about H_2S safety were answered. Safety training has also been provided to local police, fire, sheriff and ambulance services, and to interested oil and gas operators, as requested.

The enforcement, field monitoring, and inspection departments of the OCC employ 69 people. The State currently has two H_2S inspectors and a third is anticipated. In 1991, one emergency involving the accidental release of H_2S was reported to the OCC. However, the accident, which resulted in the death of one worker, was not related to the extraction of oil and gas resources.

Texas

Six agencies regulate oil and gas activities in Texas:

- Railroad Commission of Texas
- Texas Water Commission
- Texas Air Control Board
- Texas Parks and Wildlife Department
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency.

The Railroad Commission regulates most of the operations of the oil and gas industry but has no authority over the Clean Air Act Amendments. The Railroad Commission is responsible for the well spacing, construction requirements (casing etc.), and most aspects of environmental protection and works with other State Agencies to ensure that their concerns are addressed. The Texas Water Commission works with the Railroad Commission on water quality issues. The Texas Air Control Board has jurisdiction over the regulation of oil field activities that generate air emissions. The Texas Parks and Wildlife Department investigates fish kills and water pollution complaints and evaluates the effects of discharged wastes on fish and wildlife. The Railroad Commission has jurisdiction over all oil and gas activities on Federal lands in Texas, regardless of who owns the mineral rights. The U.S. Army Corps of Engineers has permitting responsibility for activities that would affect statutory wetlands.

The Texas Air Control Board (TACB) is responsible for enforcing the Texas ambient air quality standard for H_2S (discussed previously). Certain allowances are made from the air standard if the hydrogen sulfide affects only property used for other than residential, recreational, business, or commercial purposes, such as industrial property and vacant tracts and range lands not normally occupied by people (i.e., the emission limit is raised to 120 ppb/30 min). If an operator violates these ambient air levels, corrective action must be taken such as flaring, installation of vapor recovery, etc. Consequently, the unauthorized emission of H_2S that exceeds the time weighted averages for the land use discussed above is a violation of regulation and must be addressed by the operator. In addition, the TACB requires permits for facilities that handle sour gas emissions from crude oil storage which also address emergency releases from these type facilities.

Texas regulations on H_2S for drilling, extraction, and abandonment are listed under Statewide Rule 36 - Hydrogen Sulfide Safety, Section 3.36 (051.02.02.036, "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas," as amended September 1, 1976). The Hydrogen Sulfide Safety Rule in Texas—issued to address accidental releases—applies to facilities that could expose the public to concentrations of H_2S in excess of 1 x 10^5 ppb as a result of an accidental release. Operators handling hydrocarbon fluids containing 1 x 10^5 ppb or more H_2S must determine if the Rule applies to their facility. If it does, they must calculate the radius of exposure; determine if the public will be impacted; and, if so, install warning signs, ensure security measures, address storage tank requirements, install appropriate safety equipment, develop contingency plans, provide training and implement other requirements as necessary. In addition, all operators subject to Rule 36 must submit a Certificate of Compliance to the Railroad Commission to demonstrate that they have complied with these requirements. This rule requires that employees working in H_2S areas be trained in the characteristics and effects of the gas. The Railroad Commission of Texas publishes a training manual containing this information. The Texas and Oklahoma regulations are virtually identical. Most of the Texas regulations were discussed in the previous section on Oklahoma regulations. The Hydrogen Sulfide Safety Rule in Texas does require safety equipment, alarm equipment, monitors, etc., but does not specify exact types in an attempt to remain flexible and allow for new technology. It was designed for the protection of the general public rather than industry, since OSHA rules are designed to protect industry workers (personal communication, W. Freeman, Shell Oil, 6/23/93).

In Texas, the Railroad Commission does keep an emissions inventory on accidental H_2S releases. Any emissions of H_2S that are found to be of sufficient volume to present a hazard and/or any H_2S-related accidents must be reported to the Railroad Commission by the emitting facility. Operator certificates are required by the Railroad Commission to demonstrate that prevention and response measures have been taken to address accidental releases of H_2S.

There was one case of noncompliance during 1991, which involved natural gas leaking from a pipeline. The Railroad Commission canceled the Certificate of Compliance for the operators of the well, which prevented the facility from producing or selling the product until the leak was fixed. In 1991, there were emergencies involving the accidental releases of H_2S. Those accidents were discussed in Chapter III.

The enforcement, field monitoring, and inspection departments of the Railroad Commission employ 215 people. Ground testing for traces of H_2S is performed near the wells. Emission data on each well are submitted to the Railroad Commission using the Form of Compliance. When noncompliance is discovered, the Commission uses administrative proceedings to implement the following enforcement actions: enforcement letter, pipeline severance, zero allowable emissions, sealing, permit revocation and/or administrative penalties. The Railroad Commission may also seek civil penalties through the Attorney General's Office.

Michigan

The Michigan regulatory program is published in *Michigan's Oil and Gas Regulations - Act 61* (P.A. 1939 as amended and promulgated rules - Circular No. 15, revised in 1987, MDNR). Most of the regulations in the Michigan guidance were covered in the sections on Texas and Oklahoma regulations.

A review of *Michigan's Oil and Gas Regulations* reveals that the State has a comprehensive set of regulations dealing with H_2S. The Michigan rules require extensive training for all employees and contractors involved in drilling, completing, testing, producing, repair, workover or service operations. Employees must receive training in the following areas: physical properties and physiological effects of H_2S, effects of H_2S on metals and elastomers, emergency escape procedures, location and use of safety equipment, the location and operation of detection and warning systems and the location of primary and secondary briefing areas. Briefing areas are defined in *Michigan's Oil and Gas Regulations* as the areas "nearby where personnel can assemble in case of an emergency." Michigan defines safety equipment as including items such as first aid kits, dry chemical fire extinguisher, ropes, flare guns, portable H_2S detectors and warning signs.

In addition to training requirements, the Michigan oil and gas regulations contain comprehensive rules for the preparation of a contingency drilling plan in order to provide a plan for alerting and protecting personnel and the public in case of an emergency.

Five agencies regulate oil and gas activities in Michigan:

- Michigan Department of Natural Resources (MDNR)
- Michigan Department of Commerce, Public Service Commission
- U.S. Forest Services
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The Department of Natural Resources is responsible for the well spacing, construction requirements (casing, etc.), and most aspects of environmental protection. The Michigan Public Service Commission regulates the production of gas from dry natural gas reservoirs and the safety of gas pipeline construction. When dealing with split estate situations, the U.S. Forest Service will issue a Special Use Permit which allows an operator to drill within the forest boundary. When both the forest surface and corresponding mineral rights are Federally owned, the U.S. Bureau of Land Management (BLM) issues drilling permits and the U.S. Forest Service issues Surface Use Plans. The BLM issues drilling permits in all cases related to onshore Federal mineral estates (personal communication, T. Alexander, DOE, 2/22/93).

Worker safety issues are the responsibility of the Michigan Department of Labor. Part 57 of the General Industry Safety Standards Commission Safety Standards deals with oil and gas drilling operations safety standards. Under Rule 5717(1), the drilling and servicing of wells containing H_2S shall be conducted as prescribed in the American Petroleum Institute's Recommended Practice No. 49 (API, 1987).

The MDNR's Air Quality Division regulates H_2S emissions from all sources in the oil and gas industry. Rule 336.1403 states: "It is unlawful for a person to cause or allow the emission of sour gas from an oil or natural gas producing or transporting facility or a natural gas processing facility without burning or equivalent control of hydrogen sulfide and mercaptans." The Rule does allow operators with stripper wells to emit small quantities of H_2S unless one complaint is received from the public which would require some type of abatement technique to be imposed. All facilities handling H_2S are subject to these regulations.

The Geological Survey Division (GSD) of the Department of Natural Resources regulates accidental releases of H_2S in the oil and gas industry. In addition, it overlaps with the Air Quality Division on emission controls at production facilities. It appears that two agencies in the MDNR regulate H_2S handling facilities. Under Rule 299.1911-1939, operators handling hydrocarbon fluids containing more than 3×10^5 ppb H_2S must define a Well Class (defined by the radius of exposure in Rule 299.1912) to determine the applicability of the Rule. The radius of exposure is defined using the same dispersion equation as Texas Rule 36. The Rule addresses equipment standards, location standards for drilling and production equipment, contingency planning, training, drilling, testing, production operations, servicing operations and nuisance odor requirements (personal communication, W. Freeman, Shell Oil, 6/23/93).

The enforcement, field monitoring, and inspection departments for oil and gas regulation by the Geological Survey Division (GSD) of the MDNR employ 47 people. Wells are retested one year after the initial well test was performed, to check for compliance with laws. Further periodic tests are required only at the request of the MDNR. When a well is not in compliance, the MDNR can use administrative proceedings to shut down drilling processes and production, stop issuing permits to drill, stop well ownership transfers, and issue fines. Fines are also issued for falsifying records required by the GSD enabling legislation (Act 61, P.A. of 1939, amended). Violation of the Act or a rule or order under the Act carries a penalty of not more than $1,000.00 per day that the violation continues. In 1991, there was no evidence of noncompliance for the release of H_2S.

The MDNR does not keep an emissions inventory of the accidental releases of H_2S from well blowouts and flare gas releases. Emissions of H_2S are reported by industry personnel to MDNR field personnel, who may keep records on the releases. One incident was reported to the MDNR in 1990, which involved a pumper who was working on a storage tank. The exact date and nature of the incident were not available.

California

The following agencies regulate oil and gas activity in California:

- California Department of Conservation, Division of Oil and Gas
- California Water Resources Control Board and the nine Regional Water Quality Control Boards
- California Department of Health Services
- California Department of Fish and Game, Office of Spill Prevention and Response
- California/EPA Department of Toxic Substances Control
- California State Fire Marshall's Office
- California Public Utilities Commission
- California OSHA
- California Air Resources Board and the county or multi-county regional Air Pollution Control Districts
- California Governor's Office of Emergency Services
- State Lands Commission
- California Coastal Commission
- Local government agencies
- U.S. Bureau of Land Management
- U.S. Department of Energy
- U.S. Environmental Protection Agency.

The Division of Oil and Gas of the California Department of Conservation is responsible for the management and conservation of oil and gas resources. The Division issues permits for and inspects the drilling, reworking, and abandonment of oil and gas wells. Under delegated authority from the EPA, the division also issues underground injection control well permits for Class II injection wells.

Division 3 - Oil and Gas, part of the California Code of Civil Procedure, contains the California laws for conservation of petroleum and gas (CDC, 1991). Table IV-2 highlights key sections of the law applicable to H_2S releases. Although, there is no quantitative limit to H_2S emissions, the law grants the supervisor of the Oil and Gas Division, discretionary authority to control H_2S releases to ensure protection of human health and the environment.

California's Code of Regulations contains the oil and gas regulatory program enforced by the Division of Oil and Gas. These regulations are highlighted in Table IV-3. These rules include the definition of the term "critical well," requirements for contingency plans,

Table IV-2. Highlights of California Laws for Conservation of Petroleum and Gas Pertaining to H_2S Emissions

Ch., Art., Section	Subject	Description
1, 4, 3219	Blowout prevention	Where high-pressure gas exists, use adequate casing and safety devices
1, 4, 3224	Order for repair	Authorizes supervisor to order tests or repairs needed to prevent damage to life, health, natural resources, etc.
1, 4, 3228	Abandonment of wells	Protects ground and surface water from gas-bearing strata
1, 4, 3235	Complaint	Authority to investigate complaints
1, 4, 3236	Penalty	For obstructing enforcement, \$100 - \$1,000 or up to 6 months imprisonment per offense
1, 4.1, 3241	Strategy to extract gas in high risk areas	Develop strategy to extract hazardous gases from abandoned wells to protect public health and safety
1, 4.2, 3251	Define "hazardous well"	Poses danger to life, health, or natural resources
3, , 3600	Spacing wells	Well must be at least 100 feet from parcel's boundary or public road

rules include the definition of the term "critical well," requirements for contingency plans, and environmental protection.

The Division of Oil and Gas has also published a guidance document on H_2S, *Drilling and Operating Oil, Gas, and Geothermal Wells in an H_2S Environment* (Dosch and Hodgson, 1986). This guidance document reflects the American Petroleum Institute's publication RP 49, *Safe Drilling of Wells Containing Hydrogen Sulfide* (API, 1987) and recommends safety procedures for H_2S release scenarios. The California Division of Oil and Gas (CDOG) is divided into six districts. Figure IV-1 shows the six districts and the distribution of H_2S in California, presenting parts per million of H_2S gas in some California oil and geothermal fields. Table IV-4 shows the documented concentration by oil field in each district. Three of the districts are discussed here.

District 1 of the Division of Oil and Gas has three oil and gas inspectors and seven energy engineers who inspect well drilling and rework operations. The inspectors wear tri-gas monitors (H_2S, oxygen, and combustibles). The well-permitting program does not specify H_2S limits. All wells are inspected at least once a year. Idle wells must be pressure-tested periodically to minimize casing leaks. Steam flooding, an enhancement process that often creates H_2S, is used frequently in the district. District 1 authorities know of past H_2S incidents leading to human injuries; however, because records are not computerized, exact data are not available (personal communication, K. Carlson, CDOG, 8/27/92).

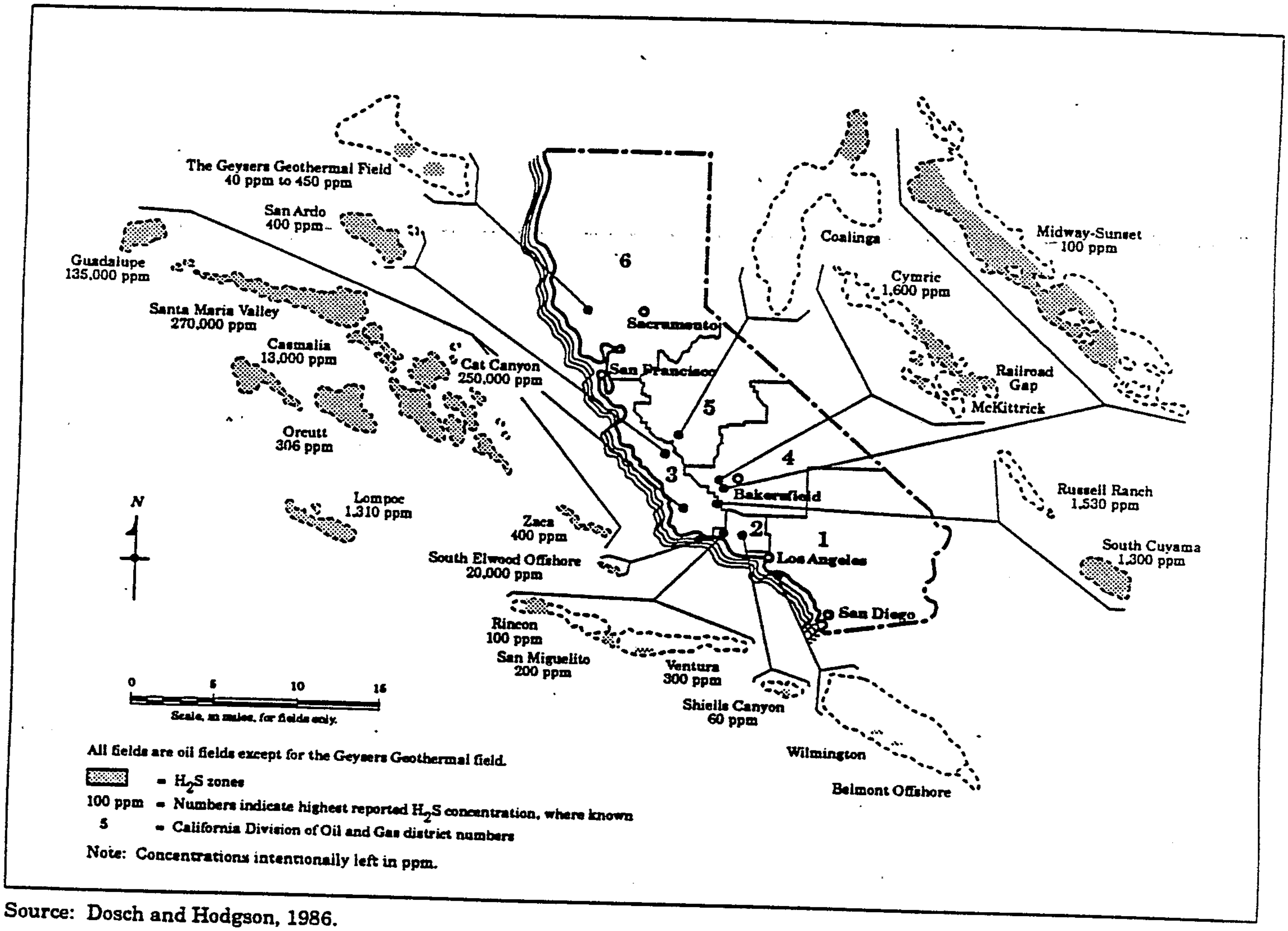
District 3 has 1,929 producing wells and 2,845 shut-in wells (i.e., no production is made on the well; its pump is turned off, the stuffing box is closed, and it is inspected to ensure no leakage). Three field inspectors cover District 3 (personal communication, A. Kollar, CDOG, 8/28/92).

District 4, which includes Kern County, has nine field inspectors, each equipped with an "escape pack" for H_2S protection. An environmental inspection is performed for every lease on every well. The inspection covers the surface area, well condition, tank condition, and operation. There are more than 40,000 wells in Kern County alone. District 4 had no records of H_2S incidents. However, inspectors in Kern County/San Joaquin Air District (described below) have documented incidents of H_2S releases (personal communication, R. Bowles, CDOG, 8/27/92).

The California Air Resources Board is authorized to enforce a statewide ambient air quality limit for H_2S emissions of 30 ppb over one hour's averaging time. However, California's air quality program is managed on a smaller scale by the 33 county or multi-county air pollution control districts (APCDs) shown in Figure IV-2 (CA Air Resources Board, 1991). Each district acts as an independent regulatory agency, establishing and

Table IV-3. Highlights of Title 14, Chapter 4 of the California Code of Regulations – Development, Regulation, and Conservation of Oil and Gas Resources

Article, Section	Subject	Description
Subchapter 1		
1, 1712	Scope	Onshore drilling and production; grants Oil and Gas Division Supervisor authority to establish field rules
2, 1720	Critical well	Addresses distances to public areas and navigable waters
2.1, 1721	Well spacing	Objectives include protecting public health, safety, welfare and the environment
3, 1722	General	Good oilfield practices, blowout prevention and control plan, prompt reporting of significant gas leaks
3, 1724.3	Well Safety Devices	Required of certain critical wells
3, 1724.4	Testing/inspecting Safety Devices	Test at least every 6 months
Subchapter 2	Environmental Protection	Requires covers on well cellars, no excessive leakage including wellheads and pipelines



Source: Dosch and Hodgson, 1986.

Figure IV-1. Parts per million of H_2S gas in some California oil and geothermal fields. Data compiled in 1976.

Table IV-4. H_2S in California Oil, Gas, and Geothermal Fields

Oil and Gas District	Fields with H_2S Concentrations $1x10^5$ ppb or Above	Fields with H_2S Concentrations Under 100 ppm	Fields with H_2S Odor, But With Concentrations Unknown
1	—	—	Wilmington, Huntington Beach, Newport, Torrance, Brea Olinda
2	Rincon, 1×10^5 ppb San Miguelito, 2×10^5 ppb Ventura, 3×10^5 ppb	Shiells Canyon 60 ppm	Aliso Canyon, Bardsdale, Big Mountain, Del Valle, Las Llajas, Oak Park, Oakridge, Ojai, Piru, Santa Paula, Santa Susana, Simi, South Mountain, Tapo Canyon So., Temescal, Torrey Canyon, and West Mountain
3	Casmalia, 1.3×10^7 ppb Cat Canyon, 2.5×10^8 ppb Cuyama So., 1.3×10^6 ppb Elwood So., Offshore, 2×10^7 ppb Guadalupe, 1.35×10^8 ppb Lompoc, 1.31×10^6 ppb Orcutt, 3.06×10^5 ppb Russell Ranch, 1.53×10^6 ppb San Ardo, 4×10^5 ppb Santa Maria Valley, 2.7×10^8 ppb Zaca, 4×10^5 ppb	—	Capitan Onshore, King City Four Deer
4	Midway Sunset, 1×10^5 ppb Cymric, 1.6×10^6 ppb	—	North Belridge, South Belridge, Blackwells Corner, Edison, Northeast Edison, Kern River, Lost Hills, McKittrick, Mount Poso, Poso Creek, Railroad Gap, and Wheeler Ridge
5	—	—	Coalinga
6	—	—	—
Geothermal District			
G3	The Geysers, $4x10^4$ - $4.5x10^6$ ppb	—	—

H_2S in some California oil and geothermal fields. Data compiled in September 1976. (Data in the first two columns are on Figure IV-1).

Source: Dosch and Hodgson, 1986.

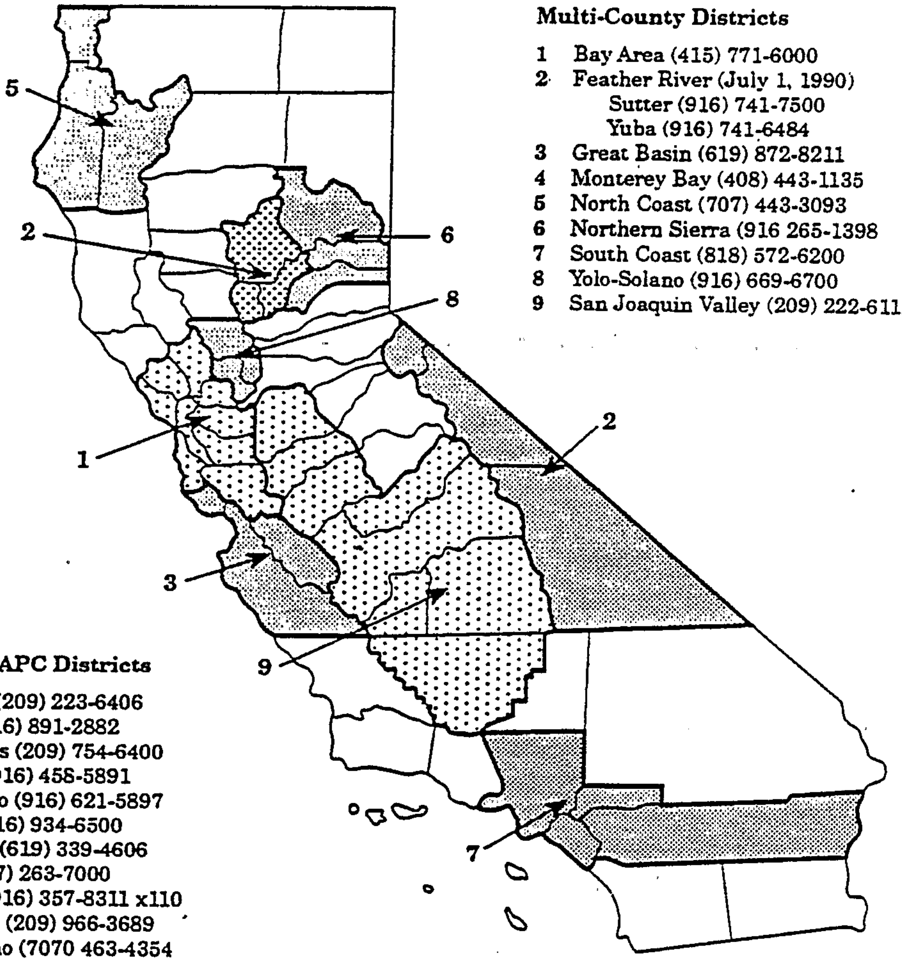
enforcing air quality rules tailored to the district's needs. Districts with significant oil production are:

Ventura County
Santa Barbara County
San Joaquin Unified Air District
South Coast Air Quality Management District
Monterey Bay Unified Air District
Bay Area Air Quality Management District.

This report highlights H_2S emissions programs in four districts: Ventura County, Santa Barbara County, San Joaquin Unified Air District, and the South Coast District.

Ventura County has Rule 54, "Sulfur Compounds," in place for air emissions containing sulfur compounds. This rule, adopted in 1968 and most recently revised in 1983, includes a limit for H_2S not to exceed 1×10^4 ppb by volume at the point of discharge. The point of discharge includes any distinguishable emission point such as valves, flanges, or process vents. There are no control technology regulations for H_2S in Ventura County other than these equipment standards. Another H_2S rule requires that the aboveground average concentration at or beyond the property boundary shall not be in excess of 60 ppb for over 3 minutes. The Ventura County limits were adopted in 1968 when the APCD was formed. Natural emissions of H_2S are low in the county's oil well fields, and H_2S monitoring is only performed when a problem is suspected (i.e., when the odor is detected). The APCD uses hand-held monitoring devices to inspect problem areas. No routine monitoring records are kept on file in Ventura County, but wells are inspected at least once a year, with large wells inspected more frequently (personal communication, K. Duval, Ventura APCD, 8/29/92). Ventura County has an enforcement staff of about 20 people, including 8 field inspectors (personal communication, K. Duval, Ventura APCD, 11/23/92).

Emission standards in Santa Barbara County are basically the same as in Ventura County. However, tighter emission limits are applied in parts of the county with SO_2 (an oxidation product of H_2S) nonattainment areas. Rule 309, "Specific Contaminants," for Santa Barbara County states that sulfur recovery units shall not emit more than 5×10^5 ppb as SO_2 or 1×10^4 ppb as H_2S. Rule 310 for odorous organic sulfides states that concentrations of organic sulfides beyond the property boundary shall not exceed 60 ppb/3 minutes or 30 ppb/hr. For gas produced and used as fuel in equipment on a well site, the sulfur content limit in the county's northern air shed is 7.96×10^5 ppb sulfur; in the southern county air shed, the limit is 2.5×10^5 ppb. Control technologies are not used on well heads for H_2S emissions. However, controls do exist for volatile organic compound (VOC) emissions from well fittings, stuffing boxes, well cellars, sumps and pits. Rules are being developed to require these controls, primarily in the surface area of the well cellar to control the release of VOC. This technology will also control H_2S emissions indirectly. The county's 10 field inspectors inspect wells for all types of emission sources at least once a year. H_2S violations via the total sulfur emission limit are not a problem because by the time



Multi-County Districts

1	Bay Area	(415) 771-6000
2	Feather River (July 1, 1990)	
	Sutter	(916) 741-7500
	Yuba	(916) 741-6484
3	Great Basin	(619) 872-8211
4	Monterey Bay	(408) 443-1135
5	North Coast	(707) 443-3093
6	Northern Sierra	(916 265-1398
7	South Coast	(818) 572-6200
8	Yolo-Solano	(916) 669-6700
9	San Joaquin Valley	(209) 222-6111

County APC Districts

Amador	(209) 223-6406
Butte	(916) 891-2882
Calaveras	(209) 754-6400
Colusa	(916) 458-5891
El Dorado	(916) 621-5897
Glenn	(916) 934-6500
Imperial	(619) 339-4606
Lake	(707) 263-7000
Lassen	(916) 357-8311 x110
Mariposa	(209) 966-3689
Mendocino	(7070 463-4354
Modoc	(916) 233-3939 x401
No. Sonoma	(707) 433-5911
Placer	(916) 889-7130
Sacramento	(916) 386-6650
San Bernardino	(619) 243-8920
San Diego	(619) 694-3307
San Luis Obispo	(805) 549-5912
Santa Barbara	(805) 961-8800
Shasta	(916) 225-5674
Siskiyou	(916) 842-8029
Tehama	(916) 527-4504
Tuolumne	(209) 533-5693
Ventura	(805) 654-2806

Source: California Air Resources Board, 1991.

Figure IV-2. Multi-county districts.

the ambient air quality standard is exceeded, the operator has already been alerted to a safety problem and is responding. The county has seven currently active H_2S ambient monitoring stations; however, these are at oil and gas processing facilities, rather than at well fields (personal communication, J. Top, St. Barbara APCD, 8/20/92).

The San Joaquin Unified Air District enforces Rule 407, "Sulfur Compounds," which limits the emission concentration of sulfur compounds at the point of discharge to 0.2 percent volume calculated as SO_2 (or 2 x 10^6 ppb SO_2). This rule, adopted in 1972 and renumbered in 1989, applies to any gas line or vapor control line from a well. Rule 220.1, "New and Modified Stationary Source Review Rules," has a trigger value for H_2S or total reduced sulfur or sulfur compounds other than SO_x of 54.79 lb/day. If this value is exceeded, the responsible party must use Best Available Control Technology (BACT) on the emission source. Rule 220.1 was adopted in September 1991 and revised March of 1992.

The San Joaquin District does not look at or enforce H_2S regulations until the 2 x 10^6 ppb SO_2 emission limit is exceeded, because the rule is based on the impact of SO_2 on human health and the environment, not on the health effects of H_2S. No ambient monitoring of H_2S is required by the district. However, the oil companies are required to keep their own records of SO_2 monitoring for two years. Companies also have H_2S monitoring data, and the State has the authority to request these data at any time (personal communication, M. Amundsen, San Joaquin, 8/21/92).

Kern County, part of the San Joaquin Unified Air District, has three of the largest producing wells in the United States. The county's production volume is exceeded only by Alaska, Texas, and Louisiana. The wells in Kern County produce a unique heavy crude and some use steam injection to enhance pumping. H_2S is a problem in well fields in the county, where numerous stripper wells (defined in Chapter II) are operating. The county has a ten-person enforcement team that performs inspections at least once a year. Steam casing collection systems, valves, fittings, etc., are inspected by staff wearing H_2S monitors. Inspectors in Kern County have been exposed to H_2S in the field. In one case, an inspector was exposed to greater than 1 x 10^6 ppb. The case involved a report from a fire department station downwind of a well and complaints of odor and illness. H_2S was measured at the station at 5 x 10^4 ppb. The source was a leaking underground gas recovery line. Companies are required to keep records of such incidents and report them to CAL OSHA (personal communication, M. Amundsen, San Joaquin Unified Air District, 8/21/92).

During conversations with Kern County representatives, it was noted that an important control technology for H_2S at wells is a casing collection system, which can be added to collect natural gas containing H_2S that has built up in the casing over time. If the natural gas pressure is not relieved, well production is hindered. Companies tend to release this gas to the atmosphere, but a casing collection system can treat the gas by vapor incineration (98 to 99 percent hydrocarbon destruction efficiency). However, the economic incentive to put casing collection systems on stripper wells is normally low due to the low volume of oil produced (personal communication, M. Amundsen, A. Phillips, San Joaquin, 8/21/92).

The South Coast Air Quality Management District has no specific regulations pertaining to H_2S or oil production. Rules in place that indirectly control H_2S emissions include Rule 431.1, "Sulfur Content of Gaseous Fuels," which states that, effective May 1994, natural gas cannot be burned or sold for burning if it contains greater than 4×10^4 ppb total sulfur. This rule also requires organic vapor recovery systems, which would recover any H_2S gas along with the volatile organics. Rule 402 could also apply to H_2S, particularly for stripper wells that are too small for permitting. This rule is a nuisance rule that could be used to close wells if, for example, neighbors complained about H_2S odors or other health effects (personal communication, C. Bhatti, South Coast AQMD, 8/25/92). The South Coast District's enforcement program is managed as part of the Stationary Source Compliance Office, which has a staff of 500 (personal communication, C. Bhatti, South Coast AQMD, 11/23/92).

California's Occupational Safety and Health Administration is authorized to administer the Federal OSHA program. There are two OSHA standards that apply to H_2S. One focuses on the maintenance and use of valves. The second is the Permissible Exposure Limit for H_2S. It is difficult to monitor compliance with this limit because operations are outdoors. CAL OSHA maintains a database of occupational accidents. No accidents were found in the database related to H_2S releases at California oil wells dating back to 1982 (personal communication, R. Hayes, CAOSHA, 9/11/92). However, H_2S incidents were recorded in some of the Air Pollution Control Districts and Division of Oil and Gas Districts (personal communication, M. Amundsen, San Joaquin Unified Air District, 8/21/92).

The California Water Resources Control Board is generally responsible for the protection of the State's waters and for preserving all present and anticipated beneficial uses of these waters. The California Department of Health Services is responsible for the regulation of hazardous wastes. It determines which waste streams and constituents are hazardous under California's laws. The State Land Commission has joint responsibility with the Division of Oil and Gas for wells on State-owned, onshore lands.

The Office of Emergency Services administers Chapter 6.95 of the California Health and Safety Code which states that every business handling any hazardous material greater than 55 gal., 500 lb. or 200 cubic feet (gaseous material) must register and develop an emergency response plan and business plan. If the business handles extremely hazardous substances onsite exceeding threshold planning quantities (500 lb for H_2S), a preliminary analysis of the facility must be made to determine if a significant risk potential exists for accidental release of the extremely hazardous substance. If the potential does exist, the facility must develop and submit a "risk management and prevention program" that addresses how to reduce or eliminate the potential for accidental release (personal communication, Dr. F. Lercari, Office of Emergency Services, 9/13/93).

A Comparison of H_2S Regulatory Programs in Four States

Table IV-5 presents a summary of regulatory programs for H_2S across California, Michigan, Oklahoma, and Texas. This summary addresses the area of "state ... control standards, techniques, and enforcement" designated for evaluation in Section 112(n)(5) of the Clean Air Act Amendments. Appendix B tabulates components of the States' regulatory programs in greater detail.

Texas, Oklahoma, and California have H_2S ambient air quality standards in place. The California standard (30 ppb over 1-hr averaging time) is more stringent than the Texas standard (80 ppb over 0.5-hr averaging time) and the Oklahoma standard (100 ppb over 0.5-hr averaging time). Michigan does not have ambient air quality standards for H_2S.

The number of agencies in each State regulating oil and gas operations ranges from two in Oklahoma and Michigan to eleven in California. The enforcement staff, which includes inspectors and field monitoring staff, numbers 69 in Oklahoma, 215 in Texas, and 47 in Michigan. California's air emissions program is regulated by districts. The Santa Barbara District, an area with high concentrations of H_2S in its oil fields, has 10 field inspectors who are also responsible for inspecting other commercial operations. Kern County, California, has a staff of 10 field inspectors who also have other inspection responsibilities.

Michigan, Oklahoma, and Texas each have H_2S-specific regulations related to public safety. In California, State law grants the Director of the Division of Oil and Gas discretion to require additional controls (for areas such as H_2S emissions) on a case-by-case basis. However, none of the four States has specific H_2S standards in place to protect the environment, i.e., ecological protection.

Of the four States reviewed, only Texas maintains an inventory of accidental releases of H_2S from drilling and production operations. However, all four states require notification when threatening accidental releases occur. None of the four States requires reporting of H_2S routine emissions. "Routine" excludes such incidents as vapor recovery unit failures and other equipment upsets.

Texas, Oklahoma, and Michigan require worker safety training for H_2S. California's Division of Oil and Gas, however, provides guidance on worker safety in the form of a publication (Dosch and Hodgson, 1986).

Other Large Producing States

The EPA gathered initial information on several State regulations and later contacted selected State agencies to obtain additional information on the unique aspects of the State regulations governing H_2S emissions in the oil and gas industry. The results of each State review are summarized in the following sections.

Table IV-5. A Comparison of Four States' H_2S Regulatory Programs

H_2S Area	Oklahoma	Texas	Michigan	California
Ambient air quality standard?	0.10 (0.5 hr)	0.08 (0.5 hr)	No	0.03 (1 hr)
Number of State agencies regulating oil/gas	3	4	2	6
Size of enforcement/ inspection staff	69	215	47	*
Specific H_2S regulations for:				
Public Safety	Yes	Yes	Yes	No
Ecological Protection (administered by environmental agency)	No	No	Not clear	No
Inventory of accidental releases kept by State?	No	Yes	No	No
Routine reporting of emissions required?	No	No	No	No
Notification of a threatening accidental release?	Yes	Yes	Yes	Yes
H_2S training required?	Yes	Yes	Yes	Guidance

*Enforcement staff in California (example counties)

Santa Barbara County Air Pollution Control District:	10
Kern County (in San Joaquin Unified Air District):	10
California Division of Oil and Gas – District 7:	10
California Division of Oil and Gas – District 4:	9

Louisiana

Five agencies regulate oil and gas activity in Louisiana:

- Louisiana Department of Natural Resources, Office of Conservation
- Louisiana Department of Environmental Quality
- U.S. Bureau of Land Management
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency.

The Louisiana Department of Natural Resources, Office of Conservation, regulates all subsurface and surface disposal of oil- and gas-associated wastes (*Statewide Order Governing the Drilling for the Producing of Oil and Gas in the State of Louisiana*). The office has primary responsibility for all classes of underground injection control wells. The Office of Conservation coordinates with the Louisiana Department of Environmental Quality, Office of Water Resources, on any problem dealing with discharges in the oil and gas industry. The U.S. Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. The Office of Conservation does not keep an emissions inventory for accidental H_2S releases. Any emissions of H_2S that exceed the Office of Conservation standard must be reported to the Office by the emitting facility.

The enforcement, field monitoring, and inspection departments of the Office of Conservation employ 34 inspectors. Emission data are sent to the Office of Conservation when an accidental release has occurred at the well site. The Office of Conservation, through administrative proceedings, can respond with the following enforcement actions when compliance is not met: compliance letters, compliance orders, civil penalty assessments, suspension/revocation of permits and pipeline severance.

In recent years, there has been no evidence of noncompliance and no emergencies involving the release of H_2S from oil or gas wells. The drilling process is not a significant threat because underground sources of H_2S are much deeper than the wells being drilled.

New Mexico

Five agencies have responsibilities for regulating oil and gas activities in New Mexico:

- New Mexico Oil Conservation Division of the Energy, Minerals and Natural Resources Department (OCD)
- New Mexico Oil Conservation Commission
- New Mexico Water Quality Control Commission
- U.S. Environmental Protection Agency

- U.S. Bureau of Land Management.

The Oil Conservation Division of the Energy, Minerals and Natural Resources Department is responsible for regulating oil and gas industry exploration and drilling, production, and refining. Its duties include regulating "nonhazardous" liquid and solid wastes from these operations to protect water quality, public health, and the environment. The Oil Conservation Commission works in conjunction with the Oil Conservation Division. The Commission initiates rules and orders to be administered by the Division. The Water Quality Control Commission develops water quality control standards and water pollution regulations. The U.S. Bureau of Land Management has jurisdiction over all Federally owned land, with the exception of Indian lands.

The Oil Conservation Division of Energy Resources (OCD) keeps emissions inventories at the district level. There are four districts in the State of New Mexico; any accidental release of H_2S must be reported to the district division of the OCD. The enforcement, field monitoring and inspection departments of the OCD employ 18 people. Inspections are made by each district OCD office. In recent years, there has been no evidence of noncompliance with the H_2S regulations set forth by the OCD, and no emergencies involving H_2S have been reported.

New Mexico's Oil Conservation Commission Rule 118 is intended to provide for the protection of the public safety in areas where H_2S concentrations greater than 1×10^5 ppb may be encountered. This rule adopts the guidance of the American Petroleum Institute publications RP 49 and RP 55 (discussed later in this chapter) and covers drilling, extraction, and abandonment.

North Dakota

Five agencies regulate oil and gas activities in North Dakota:

- North Dakota Industrial Commission, Oil and Gas Division
- North Dakota State Department of Health and Consolidated Laboratories
- U.S. Department of Agriculture, Forest Service
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The North Dakota Industrial Commission, Oil and Gas Division, has regulatory authority over the drilling and production of oil, and is responsible for protecting the correlative rights of the mineral owners, preventing waste, and protecting all sources of drinking water. The Bureau of Land Management has jurisdiction over drilling and production on Federal lands, but the operator must obtain a permit from the Division of Oil and Gas. Drilling on forest land must comply with the rules of the U.S. Forest Service.

Any well completed or recompleted on or after July 1, 1987 must be registered with the State Department of Health and Consolidated Laboratories (NDSDH&CL). The registration process includes completion and submittal of a form which provides information about the well operator, well equipment (such as size and number of storage tanks, existence of a heater treater and type of fuel on which it is fired, flare stack height, etc.), surface equipment location, and disposition of produced gas. This form, submitted along with an analysis showing the H_2S concentration of any produced gas, constitutes registration. Information derived from the registration is entered into a shared database, which is used by the North Dakota Industrial Commission's Oil and Gas Division, for storing production data; thus, an emissions inventory which represents actual emissions can be generated from the database for all registered wells. H_2S concentrations in wellhead gas are field-pool specific; for example, within the Little Knife Oil Field, gas produced from the Madison Pool will have an H_2S concentration of approximately 9.56 percent, gas produced from the Red River Pool will be approximately 7.91 percent H_2S, and gas produced from the Duperow and Bakken pools is likely to contain only negligible amounts of H_2S. H_2S data from the registrations are, therefore, entered into the database as field-pool specific data (personal communication, D. Harman, NDSDH&CL, 5/19/93).

The enforcement, field monitoring, and inspection departments of the Division of Oil and Gas employ 14 people. The NDSDH&CL handles most of these complaint-related inspections. The Division of Oil and Gas can shut down an operation and fine up to $12,500 per day when compliance is not met. The NDSDH&CL can impose a fine and/or imprisonment.

H_2S typically constitutes between 4 and 10 percent of the oil and gas found in North Dakota. Because of this prevalence, the State has established an ambient air quality standard (shown in Table IV-1).

The NDSDH&CL typically becomes more involved in situations where routine emissions (as opposed to catastrophic/episodical releases) from a production facility result in excessive ambient concentrations. This scenario typically manifests itself in the form of citizen complaints. In these situations, it has been the Department's experience that an equipment problem, such as flare stack ignitor malfunction (i.e., low efficiency flare), storage tank gasket degradation and leakage, etc., has been the primary cause. Correction of the immediate problem and implementation of a more rigorous maintenance schedule will typically resolve these cases (personal communication, D. Harman, NDSDH&CL, 5/19/93). Acute, unpredictable releases of H_2S, such as natural gas pipeline rupture, etc., are typically handled by the North Dakota Industrial Commission; however, the Industrial Commission has had no reports of emergencies involving accidental releases of H_2S in the past two years.

Pennsylvania

Six agencies regulate oil and gas activities in Pennsylvania:

- Department of Environmental Resources,
- Bureau of Oil and Gas Management (BOGM)
- U.S. Environmental Protection Agency, Region III
- Pennsylvania Fish Commission
- U.S. Forest Service
- U.S. Bureau of Land Management.

The Bureau of Oil and Gas Management (BOGM) was created to coordinate and combine all regulatory activities of the oil and gas industry (*Oil and Gas Operators' Manual*). The U.S. Environmental Protection Agency issues permits for underground injection and secondary recovery. The Pennsylvania Fish Commission identifies pollution of surface waters and takes appropriate action under the Pennsylvania Fish and Boat Code.

The BOGM does keep records of any accidental releases; however, routine emission rates are not reported. Nearly all of Pennsylvania's H_2S problems have occurred in the northern part of the State, around Lake Erie.

The enforcement, field monitoring, and inspection departments of the BOGM employ 38 people. The Department of Environmental Resources has the following enforcement options available when compliance is not met: notice of violation, citation for summary offense, misdemeanor, civil penalty, injunction, administrative order, consent order and agreement, permit suspension and/or revocation, and bond forfeiture.

Six wells near Lake Erie have significant concentrations of H_2S that could be a threat to the surrounding environment and people. One incident in 1990 involved discharges of H_2S from a well blowout. Local authorities evacuated a neighboring town until the H_2S could be contained and the well plugged. The blowout did not cause any negative health effects or other types of injury.

In the past, Pennsylvania explored the possibility of establishing a committee that would include consultants, gubernatorial appointees, and citizens to examine H_2S in relation to the oil and gas industry and determine if a serious problem exists. It is understood that this project is currently inactive due to budget limitations.

Wyoming

There are four agencies that regulate oil and gas activities in Wyoming:

- Wyoming Oil and Gas Conservation Commission
- Wyoming Department of Environmental Quality
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The Oil and Gas Conservation Commission has the general authority over oil and gas production in the State. The Department of Environmental Quality is responsible for land applications of all types of exploration and production wastes. The Bureau of Land Management is responsible for all drilling and production on Federal lands.

The Wyoming Oil and Gas Conservation Commission does keep emissions inventories on accidental releases of H_2S. Any accidental release of the gas must be reported to the Commission immediately.

The enforcement, field monitoring, and inspection departments of the Oil and Gas Conservation Commission employ ten people. The Commission has the following enforcement options when compliance is not met: civil assessments, permits denial and revocations, and bond forfeiture.

In 1989, approximately 2,982 stripper wells in Wyoming produced over 5 million barrels of oil. In recent years, there have been no signs of noncompliance; however, there have been emergencies involving accidental H_2S releases.

FEDERAL REGULATORY PROGRAMS

Current Federal regulations potentially applicable to the oil and gas production industry's handling of hydrogen sulfide are summarized below. These include regulations of the Occupational Safety and Health Administration (OSHA), Bureau of Land Management, (BLM), U.S. Geological Survey, (USGS), Superfund Amendments and Reauthorization Act (SARA) Title III, the Clean Air Act, and others. Although the OSHA standards are applicable only to workers, they are analyzed as guidelines for reducing exposure to H_2S from both accidental releases and routine emissions.

OSHA Regulations

Currently, hydrogen sulfide emissions from oil and gas exploration and drilling are not directly addressed by OSHA regulations. The regulations that are in effect to protect workers are: OSHA Standards for General Industry (29 CFR Part 1910.1000), and the respirator standards (29 CFR Part 1910.134) and the OSHA Process Safety Management Standards (listed in Chapter III). Industries in which hydrogen sulfide occurs in quantities in excess of 1500 pounds are covered in the Process Safety Management of Highly Hazardous

Chemicals Standard (29 CFR 1910.119), but retail facilities and remote, unmanned operations are exempted. Oil and gas well drilling or servicing operations are also exempted. The potential exists that oil and gas operations that are the focus of this Report to Congress may be exempt from this OSHA standard if the facility is remotely located or if servicing operations include those studied in this Report. Table IV-6 lists current and proposed regulations pertaining to hydrogen sulfide.

Current Regulations

General Industry Standards (29 CFR 1910.1000). Acceptable concentrations for chemical exposure are listed in Section 1910 under Table Z-1-A., Limits for Air Contaminants, of the General Industry Standard (1910.1000). Effective December 31, 1992, the permissible exposure limit (PEL) time weighted average (TWA) for H_2S is 1×10^4 ppb) (14 mg/m^3). That is, an 8-hour time weighted average, such that an employee's exposure to hydrogen sulfide in any 8-hour workshift of a 40-hour workweek, shall not exceed 1×10^4 ppb. Also for hydrogen sulfide, the short-term exposure limit (STEL) is 1.5×10^4 ppb (21 mg/m^3). The 1.5×10^4 ppb STEL is the employee's 15-minute (time weighted average) exposure, which shall not be exceeded at any time during the workday. The basis for the STEL is eye irritation.

The transitional OSHA standard, whose levels have been in effect since 1966, are ceiling limits and are listed in Table Z-2 of the OSHA standard. The acceptable ceiling concentration for hydrogen sulfide is 2×10^4 ppb, with an acceptable maximum peak above the ceiling concentration of 5×10^4 ppb lasting no more than 10 minutes, and occurring only once in an 8-hour shift, if no other measurable exposure occurs. The definition of a ceiling is the employee's exposure that shall not be exceeded during any part of the workday. If instantaneous monitoring is not feasible, then the ceiling shall be assessed as a 15-minute time weighted average exposure that shall not be exceeded at any time over a working day.

Respirator Standards (29 CFR 1910.134). The OSHA Personal Protective Equipment Standard (29 CFR 1910.134) outlines the types of personal protective devices (respirators) that should be worn when the ambient concentration exceeds the standards. Specific rules pertaining to hydrogen sulfide are not included in the standard. Covered in the standard are rules requiring written standard operating procedures, and employee training and screening for ability to use the equipment. Respirator selection, use, inspection and maintenance, storage, and cleaning are covered in the standard, as is air quality in supplied air respirators.

Process Safety Management of Highly Hazardous Chemicals (29 CFR 1910.119). The CAAA instructed OSHA (in section 304), in coordination with EPA, to promulgate a chemical process safety standard to prevent accidental releases of chemicals that could pose a threat to employees. This standard was finalized in February 1992 (57 *Federal Register* 6356).

The OSHA requirements for employers include standards to:

Table IV-6. Summary of Occupational Exposure Standards for H_2S

Agency/Association	Background	Standard or Guideline
Occupational Safety and Health Administration (OSHA)[a] General Industry Standards 29 CFR 1910.1000	Current: Lists acceptable concentrations for chemical exposure in the work environment. H_2S – listed under Table Z-1-A.	TWA 10 ppm 8-hour Time Weighted Average (TWA) STEL 15 ppm 15-minute Short Term 29 Exposure Limit (STEL)
OSHA Respirator Standards 29 CFR 1910.134	Current: Covers respirator selection, use, inspection and maintenance, storage and cleaning. Requires standard operating procedures; employee screening and training.	No specific rules pertaining to H_2S
OSHA Process Safety Management of Highly Hazardous Chemicals Standards 29 CFR 1910.119	Current: Remote unmanned facilities and drilling and servicing exempted. Purpose: To prevent or minimize the consequences of catastrophic releases of highly hazardous chemicals. Some elements specified by the 1990 Clean Air Act Amendments.	Threshold quantity for H_2S: 1500 pounds; meaning that the potential exists for a catastrophic accident at facilities with more than 1500 pounds on site.
OSHA Oil and Gas Well Drilling and Servicing Standards 29 CFR 1910.270	Proposed: 1983 proposal; OSHA still supports a specific standard for oil and gas production, thus their exemption from 29 CFR 1910.119 above.	Specifics pertaining to H_2S include: monitoring programs, personal protective devices, automatic flare ignitors, spark arrestors, drilling mud programs.
National Institute for Occupational Safety and Health (NIOSH)[b] Criteria Document for a Recommended Standard for Occupational Safety and Health	Recommendations for safe levels of worker exposure to H_2S. Standards developed for healthy workers, not for the public at large.	H_2S ceiling conc.: 15 mg/m^3 (approx. 1 x 10^4 ppb), 10-minute sampling, 10-hour workday, 40-hour workweek. Evacuation: 70 mg/m^3 (approx. 5 x 10^4 ppb)
American Conference of Governmental Industrial Hygienists (ACGIH)[b] Threshold Limit Values for Chemical Substances in the Work Environment	Professional organization of industrial hygienists which publishes annually updated Threshold Limit Values (TLVs) as guidelines in the control of ocupational health standards.	TLV-TWA: 1 x 10^4 ppb, for an 8-hour workday, 40-hour workweek. TLV-STEL: 1.5 x 10^4 ppb, 15-minute weighted average, not more than 4 times/dayday.

[a] Federal regulatory agency with enforceable standards; 25 of the States and territories run their own occupational safety programs.

[b] Recommended standard.

1) Develop and maintain written safety information identifying workplace chemical and process hazards, equipment, and process technology;

2) Perform a process hazard analysis which shall include an estimate of workplace effects of a range of releases and their health and safety effects on employees;

3) Consult with employees and their representatives on the conduct and development of the process safety management program.

4) Develop and implement written operating procedures for the chemical process;

5) Provide training to employees;

6) Evaluate and monitor contractor safety standards and performance;

7) Perform pre-startup safety reviews for new and modified facilities;

8) Establish maintenance systems for critical process related equipment;

9) Establish and implement written procedures to manage changes to the process;

10) Investigate every incident that has resulted or could result in a major accident;

11) Establish and implement a plant emergency action plan.

OSHA issued its final process safety standard on February 24, 1992.

Appendix A to the process safety standard (1910.119), lists the chemicals that present a potential for a catastrophic event with respective threshold quantities. For H_2S, the threshold quantity is 1500 pounds. This means that facilities with 1500 lbs or greater of H_2S on-site would be subject to the process safety management standard. OSHA further requires that the 25 States and territories with their own occupational safety organizations adopt similar rules within 6 months.

Although hydrogen sulfide is covered in this standard, oil and gas drilling or servicing operations are exempted, along with retail facilities and normally unoccupied remote facilities. OSHA explains the reason for the drilling and servicing exemptions in its preamble to the final rulemaking (57 FR 6369), stating that "OSHA continues to believe that oil and gas well drilling and servicing operations should be covered in a standard designed to address the uniqueness of the industry." This exclusion is retained in the final standard since OSHA continues to believe that a separate standard dealing with such operation is necessary. The potential exists that oil and gas operations that are the focus of this Report to Congress may be exempt form this OSHA standard if the facility is remotely located or if servicing operations include those studied in this Report. Table IV-6 lists current and proposed regulations pertaining to hydrogen sulfide.

Proposed Regulations

In 1983, OSHA proposed an Oil and Gas Well Drilling and Servicing Standard (48 FR 57202). The proposed standard would supplement the general standards already in effect and address the operation's unique hazards, such as those related to the unusual equipment, special situations dictated by the locations of operations, and hazards resulting from well pressures. According to the Bureau of Labor Statistics, the oil and gas well drilling and servicing industry was ranked among the most hazardous industries in the United States. OSHA estimated that 95,000 workers at approximately 5,400 rigs were employed in various occupations relating to oil and gas well drilling and servicing operations. The National Institute for Occupational Safety and Health (NIOSH) conducted a study of the oil and gas industry and provided OSHA with recommendations for developing a standard. In addition to a discussion of the Bureau of Labor Statistics injury data, NIOSH's "Comprehensive Safety Recommendation - Land Based Oil and Gas Well Drilling" also referenced in an early draft a study of data NIOSH received on fatalities and injuries occurring between 1973 and 1978 in Texas and California drilling operations. NIOSH applied these statistics for the entire drilling industry and concluded that the injury incidence and severity rates for the oil and gas drilling industry were more than six times the rate of general industry. However, these statistics include hazards other than H_2S.

In 1973 OSHA decided to regulate this industry under its Construction Safety Standards (29 CFR 1926); however, the applicability of this rule was contested by the industry. As a result of the industry contention, the Occupational Safety and Health Review Commission (OSHRC) ruled several times that the construction standards were not applicable. According to OSHRC, employers engaged in oil and gas well drilling and servicing should be subject to the general industry standards found in 29 CFR 1910. New enforcement problems emerged as a result of applying general industry standards. At the time of the issuance of the proposed standard, OSHA data showed that the oil and gas industry received a higher percentage of citations than any other industry. These citations are issued only when a standard does not exist to address the hazard, but the hazard is well recognized as a potential source of serious injury. OSHA felt that the high number of citations indicated the need for standards directed to these hazards in order to assist employers in meeting their obligations under the Occupational Safety and Health Act. They stated that it was apparent that the general industry standards either did not address or inadequately addressed hazards unique to oil and gas production, possibly even contributing to the higher injury and illness rate experienced by this industry. With the help of data from numerous studies of injury and illness in the oil and gas production industry, and input from numerous states, trade associations, labor unions and industry representatives, the draft oil and gas standards were proposed in 1983. No known action on this proposal has occurred since then. Currently, the proposed oil and gas well drilling and servicing rule has not been withdrawn, but it is also not on the regulatory agenda for finalizing.

OSHA proposed specific requirements for drilling, servicing, and special services operations performed in areas where a potential for exposure to H_2S gas exists. The requirements proposed establishing and implementing a monitoring program in specified areas of the rig. The monitoring program would be applicable where the potential exists for H_2S exposure, including areas where data are unavailable or inconclusive with respect to the potential H_2S exposure. The program would use automatic environmental monitoring systems connected to an employee alarm system. Details of the program and its procedures would be required from the regulated community in written form. Testing and maintenance of the monitoring system would also be regulated under the proposal, because improperly maintained or untested systems may lead to a false sense of security for employees who rely on them for warning.

Specific respiratory protection equipment requirements were also included in the proposed regulation. All employees working in an area of potential hydrogen sulfide exposure would be required to wear or carry an approved escape-type, self-contained breathing apparatus. An approved positive-pressure respirator would be required for employees who remain in or return to the danger area.

In Appendix A to the proposed rule, OSHA also suggested the following practices to control or limit hydrogen sulfide exposure:

- automatic ignitors on the flare from the degasser, choke manifold, and mud-gas separator to burn off hydrogen sulfide;
- spark arrestors for all internal combustion engines to lessen the chance of the engine serving as a source of ignition in the event of a blowout;
- regular checking of drilling mud to assure it has the right constituents and pH to counteract H_2S;
- addition of hydrogen sulfide neutralizer to the drilling mud to prevent the gas from reaching the surface;
- installation of H_2S monitoring systems on all rigs working within 1000 feet of known or suspected H_2S zones.

Although the oil and gas well drilling and servicing rule (1910.270) was proposed in 1983 and has not been enacted, OSHA has continued to express a preference for a specific regulation pertaining to the oil and gas drilling and servicing operation in 1992, by exempting these industries from the Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents Final Rule (29 CFR 1910.109 and 1910.119; 57 FR 6356).

Impact of OSHA Regulations on Occupational and Human Health

OSHA regulations are designed to protect the worker rather than the general public or the environment. In this respect, they set levels that protect the health of workers exposed for a 40-hour workweek, rather than residents who may be exposed continuously. The OSHA permissible exposure limit (PEL) for H_2S is 10 ppb. Levels set to protect human health in general are often much more conservative since they are often based on models which assume exposure scenarios in which the person is exposed 24-hours a day for a lifetime. Non-occupational health effects levels may also account for possible developmental effects on young children and the effects of pollutants on those whose health is already compromised due to age or a chronic condition.

Four OSHA standards have the potential to protect workers exposed to H_2S. Two of these OSHA standards could apply to both workers and the public, while the other two apply specifically to workers. The OSHA general industry air contaminants and respirator standards protect the worker from H_2S exposures above certain levels. These standards address the protection of the worker from an exposure in excess of a set level through the use of personal protective equipment. The public is not protected through these two standards, since they aim to protect workers from contact with H_2S rather than prevent the release of the H_2S into the atmosphere. The process safety management standard and the proposed oil and gas well drilling and servicing standard have the potential to protect both the worker and the general public by preventing the release of H_2S.

National Institute for Occupational Safety and Health

Recommendations for safe levels of worker environmental exposure to H_2S are presented in the May 1977, *National Institute for Occupational Safety and Health (NIOSH) Criteria Document for a Recommended Standard for Occupational Exposure to Hydrogen Sulfide* (NIOSH, 1977). Hydrogen sulfide was cited as the leading cause of sudden death in the workplace (Ellenhorn and Barceloux, 1988). It was recognized as a serious hazard to the health of workers employed in energy production from hydrocarbon or geothermal sources, in the production of fibers or sheets from viscous syrup, in the production of deuterium oxide (heavy water), in tanneries, sewers, sewage treatment and animal waste disposal, in work below ground, fishing boats, and in chemical operations. Table IV-6 presents specific work practices recommended by NIOSH for the gas and oil industry.

A ceiling concentration was proposed to prevent eye effects and other adverse effects, including anorexia, nausea, weight loss, insomnia, fatigue, and headache, from prolonged exposure to hydrogen sulfide at low concentrations. The proposed ceiling concentration would also prevent acute eye effects, unconsciousness, and death, which can rapidly follow exposure to hydrogen sulfide at high concentrations. NIOSH suggests no employee be exposed to hydrogen sulfide at a ceiling concentration greater than 15 mg/m^3 (approximately 1 x 10^4 ppb), as determined with a sampling period of 10 minutes, for up to a 10-hour work shift in a 40-hour workweek. Evacuation of the area shall be required if the concentration of hydrogen sulfide equals or exceeds 70 mg/m^3 (approximately 5 x 10^4 ppb). NIOSH warns that the standard was not developed for the population-at-large, and any extrapolation beyond occupational exposures is not warranted.

The document includes monitoring requirements for all areas where there is occupational exposure to H_2S. First, there should be personal monitoring to detect each employee's ceiling exposure, with source and area monitoring as a supplement. The monitoring should be done quarterly, or as recommended by an industrial hygienist. Recording automatic monitors would be permitted to show short-term (less than 1-minute) peaks of up to 5 x 10^4 ppb, as long as no more than one occurs in any 30-minute period. These recording automatic monitors should be set up to signal spark-proof audible or visual alarms. They should have different alarms to signal concentrations of 1 x 10^4 ppb as an alert level to employees and 5 x 10^4 ppb as the level for employee evacuation.

The Secretary of Labor weighs NIOSH's recommendations, along with other considerations such as feasibility and means of implementation, in developing regulatory standards. The criteria document also contains sections on medical screening and followup of exposed employees, labeling and posting of H_2S hazards, personal protective equipment, hazard information for employees, work practices, sanitation, and monitoring and recordkeeping.

Bureau of Land Management

If a sour oil and gas well is located on Federal or Indian land, the facility operator or owner is subject to the requirements imposed by the Onshore Oil and Gas Order No. 6 developed by the Bureau of Land Management. This order requires submittal of a public protection plan by operators of sour oil and gas facilities upon detection of the potential to release a hazardous volume of H_2S (defined as concentrations of H_2S that exceed 1 x 10^5 parts per billion in the gas stream). Site-specific conditions are also criteria for determining whether or not a facility needs to submit a public protection plan. These conditions include (1) proximity to public buildings, public gathering centers, and roadways used for public use; and (2) radius and concentration of exposure. The order also has requirements for danger signs, fencing and gates, and wind direction indicators. Additional requirements include well control equipment, corrosion protection, and automatic safety valves or shutdowns for accidental release prevention.

The Bureau of Land Management does have procedures for enforcing Onshore Oil and Gas Order No. 6. Penalties for failure to comply with are cited in 43 C.F.R. 3163.1 (1992).

Minerals Management Service

The Minerals Management Service (Department of the Interior) Outer Continental Shelf Standard, MMS-OCS-1, Safety Requirements for Drilling Operations in a H_2S

Environment is the name for the former U.S. Geological Survey Outer Continental Shelf (OCS) Standard No.1. In February of 1976, the Conservation Division of the U. S. Geological Survey (USGS) released offshore rules for safety and pollution prevention in Standard No. 1, Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment (USGS, 1976). Required details of a contingency plan for emergency hydrogen sulfide situations are listed in the standard, and each platform is required to have the plan developed prior to drilling. The standard also specifies details of the personnel training program, and type, storage location and use of personnel protective equipment. Finally, the standard requires state-of-the-art equipment for blowout prevention, and specifies details of the mud program, well-testing procedures and flare system.

The standard requires H_2S monitoring equipment at all wells, except when drilling in areas known to be free of hydrogen sulfide. Upon encountering hydrogen sulfide, the safety requirements of the rules go into effect, and when concentrations reach 2×10^4 ppb the remainder of the rules dealing with hydrogen sulfide's corrosive effects must be observed. The precautions in the American Petroleum Institute Recommended Practice for Safe Drilling of Wells Containing Hydrogen Sulfide, (API RP 49) are considered supplemental to the requirements of the standard (API, 1987).

Two separate operational conditions are outlined with requirements for warning flags and notification of authorities. Moderate danger, when the threshold limit value of 10 ppm is reached, requires the display of signs and flags reading "DANGER - HYDROGEN SULFIDE - H_2S." If the concentration reaches 2×10^4 ppb, protective-breathing apparatus is required to be worn by all working personnel, and non-working personnel are required to evacuate to safe briefing areas. Extreme danger, when H_2S reaches the injurious level (5×10^4 ppb), is the point when all personnel (or all non-working personnel as appropriate) are required to evacuate. Radio communications are required to alert all known air and water craft in the immediate vicinity of the danger.

The Minerals Management Service is in the process of reproposing its standards for hydrogen sulfide.

CERCLA and EPCRA

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980 establishes broad Federal authority to deal with releases or threatened releases of hazardous substances from vessels and facilities. The Act defines a set of hazardous substances chiefly by reference to other environmental statutes; currently there are over 700 CERCLA hazardous substances. Commonly known as "Superfund," CERCLA requires that the person in charge of a vessel or facility notify the National Response Center as soon as that person has knowledge of a release of a hazardous substance in an amount equal to or greater than the reportable quantity (RQ) for that substance. Currently, hydrogen sulfide is listed as a CERCLA hazardous substance with a reportable quantity of 100 pounds.

On October 17, 1986, the President signed into law the Superfund Amendments and Reauthorization Act of 1986 (SARA), which revises and extends the authorities established under CERCLA and other laws. The Emergency Planning and Community Right-to-Know Act (EPCRA), enacted in 1986 as Title III of SARA, establishes new authorities for emergency planning and preparedness, community right-to-know reporting, and toxic chemical release reporting. It is intended to encourage and support emergency planning efforts at the State and local levels and to provide citizens and local governments with information concerning potential chemical hazards present in their communities. EPCRA is organized into three subtitles (A-C), each containing a number of subsections.

Subtitle A establishes the framework for State and local emergency planning. Section 301 requires each State to establish an emergency response commission and local emergency planning committees. Section 303 governs the development of comprehensive emergency response plans by local emergency planning committees and provision of facility information to the committee. Section 302 requires EPA to publish a list of extremely hazardous substances and threshold planning quantities (TPQs) for such substances. This list was established by EPA to identify chemical substances that could cause serious irreversible health effects from accidental releases. The list includes hydrogen sulfide, with a threshold planning quantity of 500 pounds. Any facility where an extremely hazardous substance is present in an amount in excess of the threshold planning quantity is required to notify the State commission and be included in local planning efforts. Section 304 establishes requirements for immediate reporting of certain releases of reportable quantities of extremely hazardous substances, and CERCLA Hazardous Substances, to the local planning committees and State emergency response commissions. These requirements are similar to the release reporting provisions under Section 103 of CERCLA. Section 304 also requires follow-up reports on each release, its effects, and response actions taken.

Only those sour oil and gas wells and well-site facilities that have 500 pounds or more of H_2S present at the well facility are subject to the planning requirements. The reportable quantity of H_2S is 100 pounds. Therefore, releases into the environment at or above 100 pounds must be reported in accordance with CERCLA 103 and EPCRA 304.

Subtitle B provides the mechanism for community awareness of hazardous chemicals present in the locality. This information is critical for effective local contingency planning. If the owner or operator of a facility is required to prepare or have available a Material Safety Data Sheet (MSDS) for a hazardous chemical under the Occupational Safety and Health Act of 1970 and regulations promulgated under that Act, Section 311 requires that owner or operator to submit MSDSs, or a list of the chemicals for which the facility is required to have an MSDS, to the local emergency planning committees, State emergency response commissions, and local fire departments. Under Section 312, owners and operators of facilities that must submit an MSDS under Section 311 are also required to submit chemical inventory information on the hazardous chemicals present at the facility. The threshold for reporting for H_2S under sections 311 and 312 is 500 pounds. Only facilities that have more than the threshold quantity need to report under sections 311 and 312, unless

MSDS or inventory information is specifically requested by the State Emergency Response Commission (SERC) or Local Emergency Planning Committee (LEPC). The owner or operator must submit an inventory form containing an estimate of the maximum amount of hazardous chemicals present at the facility during the preceding year, an estimate of the average daily amount of hazardous chemicals at the facility, and the location of these chemicals at the facility. Section 313 requires that certain facilities with ten or more employees that manufacture, process, or use a "toxic chemical" in excess of a statutorily-prescribed quantity submit annual information on the chemical and releases of the chemical into the environment. This information must be submitted to EPA and to the appropriate State offices annually. Hydrogen sulfide is not listed as a toxic chemical for which annual release information is required.

Subtitle C contains general provisions concerning trade secret protection, enforcement, citizen suits, and public availability of information.

Clean Air Act Section 112(r) - Accident Prevention

The Clean Air Act Amendments of 1990 established programs to prevent accidental releases of extremely hazardous substances and to assure that mitigation and response measures are in place in the event that a release does occur. Section 112(r) of the Clean Air Act establishes the responsibility for prevention of releases of extremely hazardous substances as the general duty of owners and operators of facilities that produce, process, handle or store such substances. Section 112(r) also requires that EPA promulgate a list of at least 100 substances that could cause death, injury or serious adverse effects to human health or the environment. Facilities with threshold quantities of the listed substances will be required to establish risk management programs and to prepare risk management plans. The statute requires EPA to promulgate regulations concerning risk management plans and other aspects of accident prevention. H_2S is one substance to which these requirements will apply as mandated in the statute.

The general duty clause is intended to establish as a responsibility of the facility owner the prevention of accidental releases and minimization of the consequences of accidental releases which do occur. Responsibilities include the conduct of appropriate hazard assessments and the design, operation, and maintenance of a safe facility. This means that facilities must be equipped for release mitigation and community protection should a release occur. The clause in the Clean Air Act Amendments refers to and is correlated with the general duty clause contained in the Occupational Safety and Health Act administered by OSHA. The OSHA clause was designed for situations for which there is no specific OSHA regulation or standard. Recognition of the hazard by the owner or operator, or within an industry, of the industry has been one standard under the OSHA general duty clause (U.S. Senate 1989). Therefore, the general duty clause places on the owners and operators of facilities the responsibility to adhere to applicable industry codes and standards for safety, accident prevention, and response.

The accidental release prevention list criteria include severity of acute adverse health effects, likelihood of accidental release, and potential magnitude of human exposure. A threshold quantity is to be established for each regulated substance to account for toxicity, dispersibility, reactivity, volatility, combustibility, or flammability of the substance and the amount anticipated to cause adverse health effects in an accidental release. The list and threshold quantities were proposed on January 19, 1993 (58 FR 5102). H_2S is listed as a toxic, and other substances present at oil and gas sites, such as methane, ethane, propane, and other hydrocarbons, are listed as flammables. Facilities with threshold quantities of the regulated substances will be required to prepare risk management plans (RMPs) and implement risk management programs. The RMPs will include a summary of assessments of offsite consequences for a range of accidental releases (including worst-case accidental releases) and a history of accidental releases. Facilities must also describe release prevention and emergency response programs developed under the risk management regulations as part of the RMP process.

Clean Air Act - PSD Program

There is no NAAQS which addresses hydrogen sulfide; however, emissions of H_2S are regulated under the Prevention of Significant Air Quality Deterioration (PSD) Program. PSD is designed to allow for industrial growth within specific air quality goals. The basic goals of the PSD regulations are (1) to ensure that economic growth will occur in harmony with the preservation of existing clean air resources to prevent any new nonattainment problems; (2) to protect the public health and welfare from any adverse effect which might occur even at air pollution levels better than the national ambient air quality standards; and (3) to preserve, protect and enhance the air quality in areas of special national or regional natural, recreational, scenic, or historic value, such as national parks and wilderness areas.

PSD permits are required for stationary sources located in areas designated, pursuant to section 107 of the CAA, as attainment or unclassifiable for a criteria pollutant. Major sources or modifications are those emitting either at least 100 tons per year or 250 tons per year of any pollutant regulated under the CAA, depending on the source category of the PSD listed pollutants. Major sources in nonattainment areas would be regulated under permit requirements persuant to Part D under title I of the CAA.

The CAA has set significance levels, below which a PSD permit is not required. Two tables set the significance values, one for defining significant emissions changes, in tons per year; and the other for defining significant air quality changes, in $\mu g/m^3$. For hydrogen sulfide, the applicable emissions threshold is the significant emission rate of 10 tons per year. An exemption from the monitoring provision of the permitting regulations for hydrogen sulfide is set as a 1-hour average concentration of 0.02 $\mu g/m^3$. Hydrogen sulfide emissions are also counted as part of the Total Reduced Sulfur and Reduced Sulfur, both having significance values set at 10 tons per year. These pollutant classes are regulated primarily to avoid nuisance (odor) problems.

The applicability of the PSD permit program to oil and gas extraction wells would be dependent on the amount of emissions and the grouping of the wells (i.e., whether several wells would be combined for calculation of emissions). In general, it appears that most oil and gas extraction wells would not likely be subject to PSD regulations based on the applicability criteria.

INDUSTRY-RECOMMENDED SAFETY AND ENVIRONMENTAL PROTECTION PROCEDURES

This section summarizes selected industry standards and practices for managing H_2S releases to the atmosphere. The American Petroleum Institute (API) has developed and published design, construction, and operating standards. Certain aspects of these standards pertaining to accidental release prevention were discussed in the previous chapter.

API Recommended Practices

The American Petroleum Institute (API), an industry-wide technical organization, has published several recommended practices (RP) pertaining to hydrogen sulfide in the oil and gas production industry. These voluntary guidelines are intended to maintain worker and public safety and health. Table IV-7 lists API Recommended Practices pertinent to production and operations in formations containing H_2S.

Control Standards

API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide (April 15, 1987) and API RP 55, Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide (October 1981; reissued March, 1983; and preparation of a second edition began in 1990) are the two main documents dealing with H_2S in oil and gas production. It is expected that the revised RP 55 will provide information similar in scope to that in the document currently under revision, but with additional detail and more current references. These recommended practices do not set a control level for H_2S emissions; rather they identify situations to which the practices apply. They are applicable in oil and gas operations where the potential exists for atmospheric concentrations of H_2S to reach 2×10^4 ppb. They also apply "where the fluids handled contain sufficient H_2S to produce a partial pressure above 0.05 pounds per square inch absolute (psia) and the total pressure is 65 psia or greater, or where internal or external stresses are present which could result in pipe or equipment failure due to sulfide stress cracking and/or hydrogen embrittlement" (API, 1987). In these cases, materials must meet National Association of Corrosion Engineers (NACE) standards.

Control Techniques

The control techniques discussed in the API Recommended Practices take two approaches to worker and public safety. First, when hydrogen sulfide has already been

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Table IV-7. Reviewed American Petroleum Institute* Documents Pertaining to H_2S in Oil and Gas Production

Document	Date	Title	Topics Covered
Recommended Practice 49 (RP49)	2nd Edition April 15, 1987	Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide	Personnel training and protective equipment. Locations. Rig and well equipment. Rig operations in H_2S environments. Contingency planning and emergency procedures. Properties and effects of H_2S and SO_2. Sour environment definition.
Recommended Practice 51 (RP51)	1st Edition October 1974 Reissued May 1982	API Recommended Onshore Production Operating Practices for Protection of the Environment	Producing wells. Lease roads, gathering systems and pipelines. Production and water handling facilities. Oil discharge – prevention and cleanup.
Recommended Practice 53 (RP53)	2nd Edition May 25, 1984	Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells	Arrangement (surface and subsea) and/or installation of: blowout preventers, choke and kill units and lines, closing units, auxilliary equipment, pipe stripping, marine riser systems. Inspection and testing. Sealing components. Blowout modifications for H_2S environments.
Recommended Practice 54 (RP54)	2nd Edition May 1, 1992	Recommended Practices for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations	Injuries and first aid. Protective equipment. Fire prevention. Drilling and well servicing rig equipment and electrical systems. Wireline service. Stripping and snubbing. Drill stem testing. Operations (including H_2S environment).
Recommended Practice 55 (RP55)	1st Edition October 1981 Reissued March 1983 (revision in progress)	Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide	Personnel training and protective equipment. Contingency plans and emergency procedures. Design, construction, and operating procedures. Surveillance and maintenance. Continuous H_2S monitoring equipment. Supplementary guidance and reference material for H_2S operations.
Specification 6A (SPEC 6A)	16th Edition October 1, 1989	Specification for Wellhead and Christmas Tree Equipment, Supplement 1 and 2	Design and performance. Materials. Welding. Quality control. Equipment marking, shipping, storing, and specific requirements.

*American Petroleum Institute; 1220 L Street, Northwest; Washington, DC 20005.

released, worker and public safety is protected through the use of monitoring programs, personal protective devices and contingency plans for evacuations. Second, the engineering approach uses design, construction, and operating procedures to prevent the release of hydrogen sulfide to the atmosphere. The prevention of equipment damage due to corrosion (sulfide stress cracking) and the techniques for prevention of blowouts in API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells, are two main considerations in this more site- specific engineering control technique.

API RP 49, which deals with drilling in a hydrogen sulfide environment, contains the following recommendations for well siting in order to protect workers from the effects of hydrogen sulfide accumulation at the well site: "Rig components should be arranged on a location such that prevailing winds blow across the rig in a direction that will disperse any vented gas from the areas of the wellhead, choke manifold, flare stack or line, mud/gas separator, drilling fluid tanks, reserve pits, shale shaker, and degasser away from any potential ignition source (i.e., engines, generators, compressors, crew quarters, etc.) and areas used for personnel assembly. All equipment should be located and spaced to take advantage of prevailing winds and to provide for good air movement to eliminate as many sources of potential gas accumulation as possible" (API, 1987).

Other siting recommendations in API RP 49, shown in Figure III-4, are the use of caution signs at entrance and exit roads to warn of hydrogen sulfide concentrations above 2×10^4 ppb and danger flags to warn of extreme danger when the concentration exceeds 5×10^4 ppb. These signs are required to stay in place when flaring of the hydrogen sulfide could produce sulfur dioxide concentrations in excess of 5×10^3 ppb. Protection or briefing centers should be placed upwind or perpendicular to the prevailing wind, with wind direction indicators easily visible from the briefing location and all work locations. Mechanical ventilation, large fans or bug blowers, should be available for use during light wind conditions to prevent the hydrogen sulfide from accumulating in low lying locations. The locations of drilling fluid systems, power plants, burn pits, and flare stacks are also discussed from the vantage point of worker safety after the release of hydrogen sulfide.

Both API RP 49 (pertaining to drilling in a hydrogen sulfide environment) and API RP 55 (dealing with production operations) contain recommendations for personnel training. RP 55 training program topics include: the effects upon humans of various concentrations of hydrogen sulfide; protective equipment, including the use of self contained breathing apparatus rather than canister type gas masks (a filtering type mask is not appropriate for protection from hydrogen sulfide); monitoring devices; emergency procedures; material selection; and the importance of ventilation. Monitoring equipment that would set off a visual alarm at 1×10^4 ppb and an audible one at 2×10^4 ppb is recommended. Breathing equipment requirements are also discussed, including selection and storage (where they are readily available in an emergency).

Contingency plans are outlined in Section 4 of API RP 55 (API, 1983). They are recommended for each operation that has the potential for an accidental release capable of exposing the public to hazardous concentrations of hydrogen sulfide. Contingency plans should include the locations of: equipment that contains hydrogen sulfide, residences and other public facilities, evacuation routes, safety equipment, telephones, and designated briefing areas for employees. The contingency plan should also include procedures for calculating the dispersion of releases and lists of emergency telephone numbers. Finally, it is suggested that public and local officials should be briefed about the potential hazard prior to an incident, and that periodic tests of the contingency plan should be conducted.

RP 55 also covers protection of workers from the toxic effects of hydrogen sulfide due to build-up of gas concentration in confined areas. Protective equipment or purging is recommended for vessels that have previously held hydrogen sulfide. Extreme caution should be used when entering buildings containing equipment used to handle fluids containing hazardous concentrations of hydrogen sulfide. Routine use of personal protective devices is suggested in these instances.

API RP 54, Recommended Practices for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations (May 1, 1992) also addresses some aspects of personal protection from the toxic effects of hydrogen sulfide (API, 1992). This document was released after OSHA's implementation of the 1×10^4 ppb time-weighted average standard. RP 54 does not mention any specific standard or level, rather it refers the reader back to API RP 49 and API RP 55, which state that they apply to oil and gas operations where the potential exists for atmospheric concentrations to reach 2×10^4 ppb (the old OSHA ceiling standard), or where the gas could cause corrosion of the equipment. API does caution throughout their documents that the latest local, State and Federal regulations should be consulted.

Engineering controls used to prevent the production of, or the release of, hydrogen sulfide to the atmosphere are covered in the recommended practices for drilling and production (RP 49 and RP 55). API RP 55, pertaining to production, warns of the potential for introducing sulfur-reducing bacteria, which produce hydrogen sulfide, into a formation during pressure maintenance or water flooding operations (i.e., enhanced oil recovery). Operators are warned to be aware of the possibility and to act quickly if introduction occurs. If care is taken to prevent the bacteria from being introduced into formations that do not contain hydrogen sulfide, the danger of hydrogen sulfide pollution will be prevented.

Other engineering controls such as those used in design, construction, and operating practices are covered in Section 5 of RP 55. API recommends that construction materials meet specifications of the National Association of Corrosion Engineers (NACE) Standard MR-01-75: Material Requirements for Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment. These materials include all those that are exposed to fluids containing hydrogen sulfide and critical to its containment. Process factors for consideration are discussed, including the concentration of hydrogen sulfide, the maximum atmospheric temperatures expected, pressure, pH, water content of fluids, mechanical stresses, corrosional or scale effects on the system, and any others unique to each situation. Finally, piping design should eliminate dead or slow-flow areas where fluids containing hydrogen sulfide gas can collect.

Drilling fluids are important to the control of the drilling environment. According to API RP 49 (Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide), the following practices help to maintain environmental control: maintenance of a pH of 10 or higher to neutralize hydrogen sulfide (failing to maintain proper pH can cause release of hydrogen sulfide from the drilling fluid system), the use of chemical sulfide scavengers, and the use of oil-based drilling fluids. When hydrogen sulfide gas is breaking out of drilling fluids, the fluids should be routed through a mud-gas separator until the level is reduced to a safe one. Corrosion inhibitors that create a film which protects the equipment from pitting and eventual sulfide stress cracking are also recommended. Finally, extreme caution is urged in storing fluids that have been exposed to hydrogen sulfide, and in entering enclosed areas where drilling fluids have been stored.

Drill stem, casing, tubing, and wellhead selection must meet specifications of API, NACE, the American Society of Mechanical Engineers, and the American National Standards Institute, detailed in Section 5 of RP 49. Section 5 also covers procedures for limited entry tests and equipment considerations for blowout preventer units, closing units, remote choke control lines, and kill lines. Hydrogen sulfide considerations in mud/gas separators, degassers and flare system are also discussed.

Abandonment procedures are included in API RP 55, with the disclaimer that the suggested procedures do not supersede local, State or Federal regulations. Section 6.5 discusses spontaneous combustion of iron sulfide, which is produced by the reaction of H_2S with steel. Because spontaneous combustion is possible when iron sulfide is exposed to air, RP 55 suggests that iron sulfide be kept wet until it can be burned or buried. Iron sulfide also poses a hazard during well servicing operations. Acids react with the iron sulfide to produce H_2S. Damage may also occur in pipes exposed alternately to hydrogen sulfide and air. API stresses the use of monitoring equipment when well servicing operations are performed on wells where a hydrogen sulfide hazard exists.

Hydrogen sulfide in oil and gas production is also mentioned in API RP 51, API Recommended Onshore Production Operating Practices for Protection of the Environment (October 1974, reissued May 1982). General information on the protection of personnel and equipment are presented in this document (API, 1982).

FINDINGS

1. Eighteen States have short-term H_2S ambient air quality standards. Four of the nine major oil and gas producing States reviewed in this report do not have ambient air standards.

2. Ambient air quality standards range from 160 ppb per 24 hr average time to 50 ppb per 0.5 hr average time.

3. The number of State agencies involved in controlling oil and gas operations varies widely.

4. The size of enforcement staffs at the State level varies greatly, with some staff having inspection responsibility beyond oil and gas operations.

5. No specific H_2S environmental (i.e., ecological) protection standards were found for Texas, Michigan, Oklahoma and California.

6. Not all States maintain notification requirements for accidental releases of H_2S from oil and gas wells. Some do require notification when a threatening accidental release occur.

7. Reporting of routine H_2S emissions is not required in Texas, Oklahoma, Michigan, or California. "Routine" excludes such incidents as vapor recovery unit failures and other equipment upsets.

8. NIOSH suggests no employee be exposed to H_2S at a ceiling concentration greater than 15 mg/m^3 (about 1×10^4 ppb) for up to a 10 hr work shift in a 40 hr work week. Evacuation is required if the concentration equals or exceeds 70 mg/m^3 (5×10^4 ppb).

9. NIOSH requires monitoring in work areas with alarms sounding at 1×10^4 ppb and 5×10^4 ppb.

10. The Minerals Management Service requires for offshore rigs drilling in an H_2S environment: contingency plan, personnel training, state-of-the-art blowout prevention equipment, monitoring equipment and response procedures at 1×10^4, 2×10^4, and 5×10^4 ppb. Special mud programs, well-testing procedures, and flare systems are also required. This Federal regulatory program does not have an equivalent onshore program.

11. The PSD permit program applies to significant emissions of H_2S from new sources emitting greater than 250 tons per year (or 100 tons per year for certain source categories) of any regulated pollutant, i.e., major PSD sources. It also applies to modifications of existing facilities if the net emissions increase of H_2S from the modification is significant. In either case, the significant emission rate for H_2S is 10 tons per year. Also, permits do not require monitoring if the 1-hr average concentration is below 0.014 ppb (0.02 μg/m^3). H_2S is also regulated under the PSD program for its nuisance odor as part of a larger group of Total Reduced Sulfur and Reduced Sulfur (significant $\geq$ 10 tons/yr).

12. Accidental releases of H_2S can be prevented by application of process safety management principles. The following are among the ways that these principles are adopted:

    a. Under the Clean Air Act, as amended, industry has a responsibility to identify hazards, take the actions necessary to prevent chemical accidents, and to take action to mitigate accidents in the event that they do occur.
    b. OSHA has promulgated a process safety management standard that requires facilities to implement process safety management programs for chemicals including H_2S to protect workers from accidents. These same measures can also prevent chemical accidents that might affect the public. However, the OSHA requirements do not apply to remote or unstaffed facilities such as most oil and gas well sites.
    c. Under the Clean Air Act, as amended, EPA must promulgate rules that require facilities handling H_2S to implement a risk management plan designed to prevent chemical accidents that adversely affect the public.
    d. The Bureau of Land Management's Onshore Oil and Gas Order No. 6 addresses the prevention of accidental releases of H_2S on Federal or Indian lands.
    e. Several State programs address the prevention of accidental releases of H_2S. States with such programs include Oklahoma, Texas, Michigan, California, and New Mexico.
    f. Voluntary industry initiatives (e.g., codes, standards, recommended practices) such as the API RP 55, Recommended Practices for Conducting Oil and Gas Operations Involving H_2S, which is currently being revised, have been implemented by many facilities.

13. A number of Federal and State requirements exist for emergency planning in the event that an accidental release of H_2S occurs.

    a. Facilities handling quantities of H_2S greater than threshold amounts are subject to the emergency planning requirements of the Emergency Planning and Community Right-to-Know Act (EPCRA).
    b. The accidental release prevention provisions of the Clean Air Act Amendments will require facilities handling amounts of H_2S above threshold quantities to implement an emergency response program.
    c. For Federal and Indian lands, the Bureau of Land Management requires public protection plans for sour oil and gas production operations that meet certain criteria.
    d. Several States require contingency plans in the event of accidental H_2S releases. State requirements include those of Oklahoma, Texas, Michigan, California, and New Mexico.

e. API RP 55 recommends that contingency plans be developed for oil and gas extraction facilities where an accidental release of H_2S could be immediately hazardous to life or health.

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CHAPTER V
RECOMMENDATIONS

ROUTINE EMISSIONS

From the limited data available, there appears to be no evidence that a significant threat to public health or the environment exists from routine H_2S emissions from sour oil and gas extraction. States and industry are encouraged to evaluate existing design, construction, and operation principles within the framework of process safety management. EPA recommends no further legislation pertaining to routine H_2S emissions from oil and gas extraction at this time.

ACCIDENTAL RELEASES

General

The EPA recommends no further legislative action pertaining to accidental H_2S releases from oil and gas extraction activities at this time. The regulations already promulgated, and being developed, under the authorities provided to EPA in CERCLA, EPCRA, and the accidental release prevention provisions of the CAA, provide a good framework for the prevention of accidental releases and preparedness in the event that they occur.

- EPA should track implementation of current and future industry standards and recommended practices at sour oil and gas extraction facilities. An example of such industry standards is the American Petroleum Institute Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide (API RP55). EPA should consider outreach specifically directed at non-participating sectors.

- The EPA should participate in the investigation of any accidental releases associated with H_2S that cause or have the potential to cause public impacts in order to determine the root cause of such accidents. Such investigations should be coordinated with the Occupational Safety and Health Administration (OSHA) in order to encompass worker safety issues.

- The EPA should continue to investigate the need for additional rulemaking under the accidental release prevention provisions of the Clean Air Act to require implementation of certain prevention, detection, monitoring and mitigation efforts at facilities where extremely hazardous substances (such as H_2S) could generate dense gas clouds and impact the public. The level of voluntary industry initiatives and degree of participation, and accident history should be taken into account.

Facility and Local Emergency Planning Committee (LEPC)

Facilities that handle hazardous substances that could form dense vapor clouds if accidentally released, such as H_2S, should work closely with their LEPC to prevent accidents and to be prepared to respond to such accidents.

- Facilities should identify and thoroughly understand the hazards and conditions that can lead to accidental releases and the potential impacts on the public. These hazards and potential impacts should be communicated to the LEPC.
- All sour oil and gas extraction facilities and the LEPC for that area should conduct drills and exercises with workers, the community, first responders and others to test mitigation, response, and medical treatment for a simulated major H_2S accident. All such facilities should have training programs in place for H_2S emergencies.

Preparedness and Response

All sour oil and gas extraction facilities should actively conduct outreach efforts to ensure that the community is aware of the hazards of H_2S, that protective measures are in place to prevent public health impacts, and that proper actions will be taken during an emergency. Such outreach should be conducted through the LEPCs.

- All sour oil and gas extraction facilities should able to rapidly detect, mitigate, and respond to accidental releases in order to minimize the consequences. Site-specific risk factors should be taken into account.
- Because a general duty exists to design, operate, and maintain a safe facility, owners and operators of sour oil and gas facilities should use appropriate equipment for the facility to provide public safety and should implement a program to remedy the effects of wear and tear and corrosion on equipment.
- In addition to regular inspection of all equipment, owners and operators should pay particular attention to corrosion monitoring of existing flow and gathering lines and to the condition of temporarily abandoned equipment. Remedial action should be taken before accidental releases occur.
- EPA should foster the development and continued refinement of release detection and mitigation systems for hazardous substances, such as H_2S, in order to improve their reliability and effectiveness.
- All facilities that handle oil and gas with potentially harmful levels of H_2S should have proper medical treatment supplies and trained personnel available and should ensure that first responders, hospitals, and clinics in the area are prepared to treat H_2S exposure.

Research and Further Studies

- Further study on the acute exposure levels of H_2S that result in irreversible health effects or lethality in humans should be continued in order to improve emergency planning tools such as atmospheric dispersion models.

- Further research on the effects of surface roughness and obstacles on dense-gas dispersion behavior should be continued to determine their influences on toxic substance concentrations in a dispersing vapor cloud. The Liquefied Gaseous Fuels Spill Test Facility could be used for spill tests to assist in this research.

- EPA should continue to study the issues surrounding worst-case releases, their consequences, and the likelihood of worst-case or other significant releases for extremely hazardous substances and the role and relationship of these issues to prevention, preparedness, and response.

GLOSSARY

Abandon: To cease producing oil or gas from a well when it becomes unprofitable. A wildcat may be abandoned after it has been proven nonproductive. Usually, before a well is abandoned, some of the casing is removed and salvaged and one or more cement plugs are placed in the borehole to prevent migration of fluids between the various formations. In many States, wells may not be abandoned unless approved by an official regulatory agency.

Accidental Release: The unanticipated emissions of a regulated substance or other extremely hazardous substance into the air from a stationary source.

Acid: Any chemical compound, one element of which is hydrogen, that dissociates in solution to produce free-hydrogen ions. For example, hydrochloric acid, HCl, dissociates in water to produce hydrogen ions, H^+, and chloride ions, Cl^-.

Additive: A substance or compound added in small amounts to a larger volume of another substance to change some characteristic of the latter. In the oil industry, additives are used in lubricating oil, fuel, drilling mud, and cement for cementing casing.

Air drilling: A method of rotary drilling that uses compressed air as its circulation medium. This method of removing cuttings from the wellbore is as efficient or more efficient than the traditional methods using water or drilling mud; in addition, the rate of penetration is increased considerably when air drilling is used. However, a principal problem in air drilling is the penetration of formations containing water, since the entry of water into the system reduces its efficiency.

Alkalinity: The combining power of a base, or alkali, as measured by the number of equivalents of an acid with which it reacts to form a salt.

Annular injection: Long-term disposal of wastes between the outer wall of the drill stem or tubing and the inner wall of the casing or open hole.

Annulus or annular space: The space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing.

API: The American Petroleum Institute. Founded in 1920, this national oil trade organization is the leading standardizing organization on oil-field drilling and production equipment. It maintains departments of transportation, refining, and marketing in Washington, D.C., and a department of production in Dallas.

Artificial lift: Any method used to raise oil to the surface through a well after reservoir pressure has declined to the point at which the well no longer produces by means of natural energy. Artificial lift may also be used during primary recovery if the initial reservoir pressure is inadequate to bring the hydrocarbons to the surface. Sucker-rod pumps, hydraulic pumps, submersible pumps, and gas lift are the most common methods of artificial lift.

Barrel (bbl): A measure of volume for petroleum products. One barrel (1 bbl) is equivalent to 42 U.S. gallons or 158.97 liters. One cubic meter (1 m^3) equals 6.2897 bbl.

Basin: A synclinal structure in the subsurface, formerly the bed of an ancient sea. Because it is composed of sedimentary rock and its contours provide traps for petroleum, a basin is a good prospect for exploration. For example, the Permian Basin in West Texas is a major oil producing area.

Bit: The cutting or boring element used in drilling oil and gas wells. Most bits used in rotary drilling are roller-cone bits. The bit consists of the cutting element and the circulating element. The circulating element permits the passage of drilling fluid and uses the hydraulic force of the fluid stream to improve drilling rates. In rotary drilling, several drill collars are joined to the bottom end of the drill-pipe column for added weight. The bit is attached to the end of the drill collar.

Blowdown: The emptying or depressurizing of a material from a vessel. The material thus discarded.

Blowout preventer (BOP): Equipment installed at the wellhead, at surface level on land rigs and on the seafloor of floating offshore rigs, to prevent the escape of pressure either in the annular space between the casing and drill pipe or in an open hole during drilling and completion operations.

Blow out: To suddenly expel oil-well fluids from the borehole with great velocity. To expel a portion of water and steam from a boiler to limit its concentration of minerals.

Borehole: The wellbore; the hole made by drilling or boring.

Casing: Steel pipe placed in an oil or gas well as drilling progresses to prevent the wall of the well from caving in during drilling and to provide a means of extracting petroleum if the well is productive.

Casing string: Casing is manufactured in lengths of about 30 ft, each length or joint being joined to another as casing is run in a well. The entire length of all the joints of casing is called the casing string.

Cement: A powder consisting of alumina, silica, lime, and other substances which hardens when mixed with water. Extensively used in the oil industry to bond casing to the walls of the wellbore.

Cement plug: A portion of cement placed at some point in the wellbore to seal it.

Christmas tree: Assembly of fittings and valves at the tip of the casing of an oil well that controls the flow of oil from the well.

Close-in: A well capable of producing oil or gas, but temporarily not producing.

Collar: A coupling device used to join two lengths of pipe. A combination collar has left-hand threads in one end and right-hand threads in the other. A drill collar.

Commercial production: Oil and gas output of sufficient quantity to justify keeping a well in production.

Completion fluid: A special drilling mud used when a well is being completed. It is selected not only for its ability to control formation pressure, but also for its properties that minimize formation damage.

Completion operations: Work performed in an oil or gas well after the well has been drilled to the point at which the production string of casing is to be set. This work includes setting the casing, perforating, artificial stimulation, production testing, and equipping the well for production. It is done prior to the commencement of the actual production of oil or gas in paying quantities, or in the case of an injection or service well, prior to when the well is plugged and abandoned.

Corrosion: A complex chemical or electrochemical process by which metal is destroyed through reaction with its environment. Rust is an example of corrosion.

Crude oil: Unrefined liquid petroleum. It ranges in gravity from 9° to 55° API and in color from yellow to black, and it may have a paraffin, asphalt, or mixed base. If a crude oil, or crude, contains a sizable amount of sulfur or sulfur compounds, it is called a sour crude; if it has little or no sulfur, it is called a sweet crude. In addition, crude oils may be referred to as heavy or light according to API gravity, the lighter oils having the higher gravities.

Cuttings: The fragments of rock dislodged by the bit and brought to the surface in the drilling mud. Washed and dried samples of the cuttings are analyzed by geologists to obtain information about the formations drilled.

Demulsify: To resolve an emulsion, especially of water and oil, into its components.

Desander: A centrifugal device used to remove fine particles of sand from drilling fluid to prevent abrasion of the pumps. A desander usually operates on the principle of a fast-moving stream of fluid being put into a whirling motion inside a cone-shaped vessel.

Desilter: A centrifugal device, similar to a desander, used to remove very fine particles, or silt, from drilling fluid to keep the amount of solids in the fluid to the lowest possible level. The lower the solids content of the mud, the faster the rate of penetration.

Disposal well: A well into which salt water is pumped; usually part of a saltwater-disposal system.

Drill: To bore a hole in the earth, usually to find and remove subsurface formation fluids such as oil and gas.

Drill collar: A heavy, thick-walled tube, usually steel, used between the drill pipe and the bit in the drill stem to weight the bit in order to improve its performance.

Drill cutting: The formation rock fragments that are created by the drill bit during the drilling process.

Drilling fluid: The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-based drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspended medium for solids, whether or not oil is present. An oil-based drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase. Drilling fluids are circulated down the drill pipe and back up the hole between the drill pipe and the walls of the hole, usually to a surface pit. Drilling fluids are used to lubricate the drill bit, to lift cuttings, to seal off porous zones, and to prevent blowouts. There are two basic drilling media: muds (liquid) and gases. Each medium comprises a number of general types. The type of drilling fluid may be further broken down into numerous specific formulations.

Drill pipe: The heavy seamless tubing used to rotate the bit and circulate the drilling fluid. Joints of pipe 30 ft long are coupled together by means of tool joints.

Drill site: The location of a drilling rig.

Drill stem: The entire length of tubular pipes, composed of the kelly, the drill pipe, and drill collars, that make up the drilling assembly from the surface to the bottom of the hole.

Drill string: The column, or string, of drill pipe, not including the drill collars or kelly. Often, however, the term is loosely applied to include both the drill pipe and drill collars.

Emulsion: A mixture in which one liquid, termed the dispersed phase, is uniformly distributed (usually as minute globules) in another liquid, called the continuous phase or dispersion medium. In an oil-water emulsion, the oil is the dispersed phase and the water the dispersion medium; in a water-oil emulsion the reverse holds. A typical product of oil wells, water-oil emulsion also is used as a drilling fluid.

Embrittlement: Through chemical reactions with H_2S, steel and other materials become more brittle and more likely to break.

Emulsion breaker: A system, device, or process used for breaking down an emulsion and rendering it into two or more easily separated compounds (like water and oil). Emulsion breakers may be (1) devices to heat the emulsion, thus achieving separation by lowering the viscosity of the emulsion and allowing the water to settle out; (2) chemical compounds, which destroy or weaken the film around each globule of water, thus uniting all the drops; (3) mechanical devices such as settling tanks and wash tanks; or (4) electrostatic treaters, which use an electric field to cause coalescence of the water globules. This is also called electric dehydration.

Enhanced oil recovery (EOR): A method or methods applied to depleted reservoirs to make them productive once again. After an oil well has reached depletion, a certain amount of oil remains in the reservoir, which enhanced recovery is targeted to produce. EOR can encompass secondary and tertiary production.

EPA: United States Environmental Protection Agency.

Exploration: The search for reservoirs of oil and gas, including aerial and geophysical surveys, geological studies, core testing, and the drilling of wildcats.

Extraction: The physical removal of oil and gas from a well.

Field: A geographical area in which a number of oil or gas wells produce from a continuous reservoir. A field may refer to surface area only or to underground productive formations as well. In a single field, there may be several separate reservoirs at varying depths.

Flare: Combustion of wastegases, such as H_2S or natural gas, which are not able to be profitably brought to market.

Flowing well: A well that produces oil or gas without any means of artificial lift.

Formation: A bed or deposit composed throughout of substantially the same kinds of rock; a lithologic unit. Each different formation is given a name, frequently as a result of the study of the formation outcrop at the surface and sometimes based on fossils found in the formation.

Gas plant: A plant for the processing of natural gas, by other than solely mechanical means, for the extraction of natural gas liquids, and/or the fractionation of the liquids into natural gas liquid products such as ethane, butane, propane, and natural gasoline.

Heater-treater: A vessel that heats an emulsion and removes water and gas from the oil to raise it to a quality acceptable for pipeline transmission. A heater-treater is a combination of a heater, free-water knockout, and oil and gas separator.

Hydrocarbons: Organic compounds of hydrogen and carbon, whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous; the largest are solid.

Ignitability (RCRA): The hazardous characteristic of ignitability for purposes of RCRA is defined in 40 CFR 261.21 and is generally a liquid with a flash point less than 140 degrees F., a non-liquid that causes fire under a friction condition, an ignitable compressed gas, or is an oxidizer.

Inhibitor: An additive used to retard undesirable chemical action in a product. It is added in small quantities to gasolines to prevent oxidation and gum formation, to lubricating oils to stop color change, and to corrosive environments to decrease corrosive action.

Injection well: A well in which fluids have been injected into an underground stratum to increase reservoir pressure.

Kelly: A pipe attached to the top of a drill string and turned during drilling. It transmits twisting torque from the rotary machinery to the drill string and ultimately to the bit.

LC_{50} (median lethal concentration): The concentration of a chemical required to cause death in 50% of the exposed population when exposed for a specified time period, and observed for a specified period of time after exposure. Refers to inhalation exposure concentration in the context of air toxics (may refer to water concentration for tests of aquatic organisms or systems).

Lease: A legal document executed between a landowner (or a lessor) and a company or individual, as lessee, that grants the right to exploit the premises for minerals or other products. The area where production wells, stock tanks, separators, and production equipment are located.

Lowest-observed-adverse-effect level (LOAEL): The lowest dose or exposure level of a chemical in a study at which there is a statistically or biologically significant increase in the frequency or severity of an adverse effect in the exposed population as compared with an appropriate, unexposed control group.

Mud: The liquid circulated through the wellbore during rotary drilling and workover operations. In addition to its function of bringing cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids to the formation. Although it originally was a suspension of earth solids (especially clays) in water, the mud used in modern drilling operations is a more complex, three-phase mixture of liquids, reactive solids, and inert solids. The liquid phase may be fresh water, diesel oil, or crude oil and may contain one or more conditioners.

Natural gas: Naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface. The principal hydrocarbon constituent is methane.

No-observed-adverse-effect level (NOAEL). The highest experimental dose at which there is no statistically or biologically significant increases in frequency or severity of adverse health effects, as seen in the exposed population compared with an appropriate, unexposed population. Effects may be produced at this level, but they are not considered to be adverse.

Odor perception threshold: The lowest concentration at which a substance is first able to be smelled.

Oil base muds: A drilling fluid that is a water-oil emulsion with oil as the continuous phase. The oil content ranges from 50-98% oil. Oil muds are used to reduce drilling torque and to stabilize reactive shales that impede the drilling process.

Oil and gas separator: An item of production equipment used to separate the liquid components of the well stream from the gaseous elements. Separators are vertical or horizontal and are cylindrical or spherical in shape. Separation is accomplished principally by gravity, the heavier liquids falling to the bottom and the gas rising to the top. A float valve or other liquid-level control regulates the level of oil in the bottom of the separator.

Oil field: The surface area overlying an oil reservoir or reservoirs. Commonly, the term includes not only the surface area but also the reservoir, wells, and production equipment.

Operator: The person or company, either proprietor or lessee, actually operating an oil well or lease.

Packer: A piece of downhole equipment, consisting of a sealing device, a holding or setting device, and an inside passage for fluids. It is used to block the flow of fluids through the annular space between the tubing and the wall of the wellbore by sealing off the space. The packer is usually made up in the tubing string some distance above the producing zone. A sealing element expands to prevent fluid flow except through the inside bore of the packer and into the tubing. Packers are classified according to configuration, use, and method of setting and whether or not they are retrievable (i.e., whether they can be removed when necessary, or whether they must be milled or drilled out and thus destroyed).

Perforate: To pierce the casing wall and cement to provide holes through which formation fluids may enter, or to provide holes in the casing so that materials may be introduced into the annulus between the casing and the wall of the borehole. Perforating is accomplished by lowering into the well a perforating gun, or perforator, that fires electrically detonated bullets or shaped charges from the surface.

Permeability: A measure of the ease with which fluids can flow through a porous rock.

pH: A measure of the acidity or alkalinity of a solution, numerically equal to 7 for neutral solutions, increasing with increasing alkalinity and decreasing with increasing acidity.

Primary recovery: Oil production in which only existing natural energy sources in the reservoir provide for movement of the well fluids to the wellbore.

Produced water: The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas. It can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Producing zone: The zone or formation from which oil or gas is produced.

Production: The phase of the petroleum industry that deals with bringing the well fluids to the surface and separating them. Production also includes storing, gauging, and otherwise preparing the product for the pipeline.

Production casing: The last string of casing or liner that is set in a well, inside of which is usually suspended the tubing string.

RCRA (Resource Conservation and Recovery Act): The Federal statute enacted in 1976 (and subsequent amendments) which amended the Solid Waste Disposal Act. Among other things, RCRA and its amendments established and/or augmented three significant programs: the hazardous waste management program, the solid waste program, and the underground storage tank program.

Reference concentration (RfC): An estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime.

Reservoir: A subsurface, porous, permeable rock body in which oil or gas or both are stored. Most reservoir rocks are limestones, dolomites, sandstones, or a combination of these. The three basic types of hydrocarbon reservoirs are oil, gas, and condensate. An oil reservoir generally contains three fluids--gas, oil, and water--with oil the dominant product. In the typical oil reservoir, these fluids occur in different phases because of the variance in their gravities. Gas, the lightest, occupies the upper part of the reservoir rocks; water occupies, the lower part; and oil occupies, the intermediate section. In addition to occurring as a cap or in solution, gas may accumulate independently of the oil; if so, the reservoir is called a gas reservoir. Associated with the gas, in most instances, are salt water and some oil. In a condensate reservoir, the hydrocarbons may exist as a gas, but when brought to the surface, some of the heavier ones condense to a liquid or condensate. At the surface the hydrocarbons from a condensate reservoir consist of gas and a high gravity crude (i.e., the condensate). Condensate wells are sometimes called gas-condensate reservoirs).

Rig: The derrick, drawworks, and attendant surface equipment of a drilling or workover unit.

Routine emissions: The anticipated emissions of a regulated substance or other extremely hazardous substance into the air from a stationary source during its normal operation.

Secondary recovery: Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from extraneous sources) into the wellbore. This injection effects a restoration of reservoir energy, which moves the formerly unrecoverable secondary reserves through the reservoir to the wellbore.

Shale shaker: A series of trays with sieves that vibrate to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the sieve is carefully selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. It is also called a shaker.

Short-term exposure limit (STEL): A time-weighted average that the American Conference of Government and Industrial Hygienists (ACGIH) indicates should not be exceeded any time during the work day. Exposures at the STEL should not be longer than 15 minutes and should not be repeated more than 4 times per day. There should be at least 60 minutes between successive exposure at the STEL.

Shut-in well: A non-producing well with its pump turned off, and the stuffing box closed, which has been inspected to ensure there is no leakage.

Sour: Containing hydrogen sulfide or caused by hydrogen sulfide or another sulfur compound.

Stripper well: A well nearing depletion that produces a very small amount of oil or gas.

Tail gas: gas that leaves a sulfur recovery process after most of the H_2S has been converted to SO_2.

Tank battery: A group of production tanks located in the field, used for storage of crude oil.

Tertiary recovery: A recovery method used to remove additional hydrocarbons after secondary recovery methods have been applied to a reservoir. Sometimes more hydrocarbons can be removed by injecting liquids or gases (usually different from those used in secondary recovery and applied with different techniques) into the reservoir.

Threshold limit value (TLV): The concentration of a substance below which no adverse health effects are expected to occur for workers, assuming exposure for 8 hours per day, 40 hours per week. TLVs are published by the American Conference of Governmental Hygienists (ACGIH). This listing may be useful in identifying substances used in the workplace and having the potential to be emitted into the ambient air.

Time-weighted average (TWA): An approach to calculating the average exposure over a specified time period.

Tubing: Small-diameter pipe that is run into a well to serve as a conduit for the passage of oil and gas to the surface.

Uncertainty factor (UF): One of several, generally 10-fold factors, applied to a NOAEL or a LOAEL to derive a reference dose (RfD) from experimental data. UFs are intended to account for (a) the variation in the sensitivity among the members of the human population; (b) the uncertainty in extrapolating animal data to humans; (c) the uncertainty in extrapolating from data obtained in a less-than-lifetime exposure study to chronic exposure; and (d) the uncertainty in using a LOAEL rather than a NOAEL for estimating the threshold region.

Volatile: Readily vaporized.

Waterflood: A method of secondary recovery in which water is injected into a reservoir to remove additional quantities of oil that have been left behind after primary recovery. Usually, a waterflood involves the injection of water through wells specially set up for water injection and the removal of the water and oil from the wells drilled adjacent to the injection wells.

Wellbore: A borehole; the hole drilled by the bit. A wellbore may have casing in it or may be open (i.e., uncased); or a portion of it may be cased and a portion of it may be open.

Well completion: The activities and methods necessary to prepare a well for the production of oil and gas; the method by which a flow line for hydrocarbons is established between the reservoir and the surface. The method of well completion used by the operator depends on the individual characteristics of the producing formation or formations. These techniques include open-hole completions, conventional perforated completions, sand-exclusion completions, tubingless completions, multiple completions, and miniaturized completions.

Wellhead: The equipment used to maintain surface control of a well, including the casinghead, tubing head, and Christmas tree.

Workover: One of more of a variety of remedial operations performed on a producing oil well to try to increase production. Some examples of workover operations are deepening, plugging back, pulling and resetting the liner, and squeeze-cementing.

Workover fluids: A special drilling mud used to keep a well under control when it is being worked over. A workover fluid is compounded carefully so it will not cause formation damage.

APPENDIX A

BACKGROUND INFORMATION ON THE OIL AND GAS PRODUCTION INDUSTRY

APPENDIX A

BACKGROUND INFORMATION ON THE OIL AND GAS PRODUCTION INDUSTRY

EXPLORATION AND DEVELOPMENT

Although geological and geophysical studies provide information about potential accumulations of petroleum, only exploratory drilling can confirm the presence of petroleum.

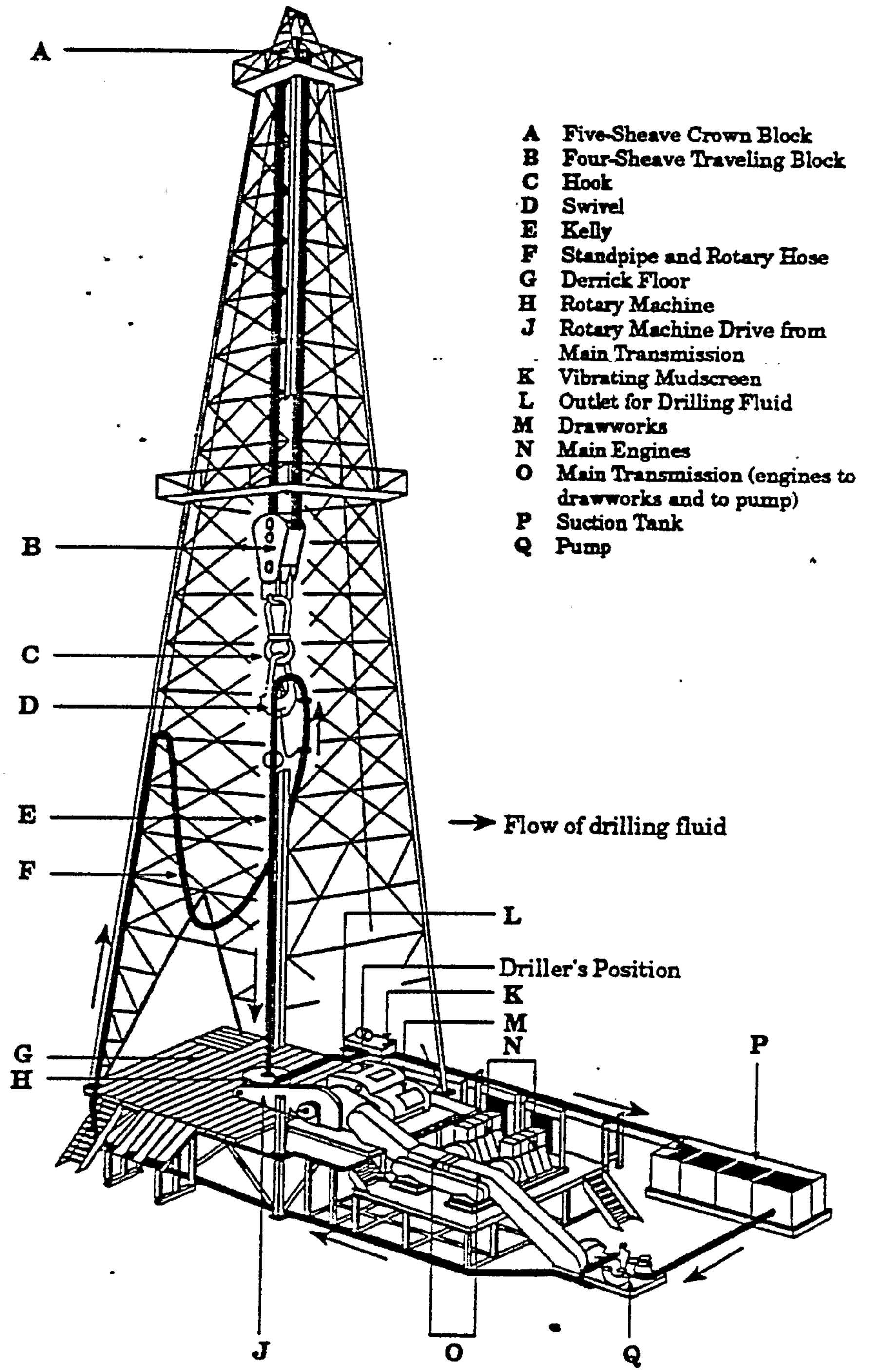
Rotary drilling, the primary drilling method in the United States, provides a safe way to control high-pressure oil/gas/water flows and allow for the simultaneous drilling of the well and removal of cuttings. This makes it possible to drill wells over 30,000 feet deep. Figure A-1 illustrates the process. Most rotary drilling operations employ a circulation system using a water- or oil-based fluid, called "mud" because of its appearance. The mud is pumped down the hollow drill pipe and across the face of the bit to provide lubrication and remove cuttings. Cuttings are removed at the surface by shale shakers, desanders, and desilters; they are then deposited in the reserve pit excavated or constructed next to the rig. Air drilling, which is considerably faster and less expensive than drilling with water- or oil-based fluids, is used in areas where high pressure or water-bearing formations are not anticipated.

Potential producing zones are normally measured and analyzed during exploratory drilling. If evidence of hydrocarbons is found, a drill stem test can show whether commercial quantities of oil and gas are present. If so, the well is prepared for production. This is called "completion." The most common method is the "cased hole" completion. Production casing is run into the hole and cemented permanently in place. Then one or more strings of production tubing are set in the hole, productive intervals are isolated with packers, and surface equipment is installed. The well is not actually completed until a gun or explosive charge perforates the production casing and begins the flow of petroleum into the well (U.S. EPA, 1987). Figure A-2 shows a cross section of a common well.

While a well is being drilled, heavy fittings have to be installed at the surface where the casing is attached, as each string of casing is inserted into the hole. Each part of the casing head is supported by a part of the casing head which was installed at the top of the next larger string of casing when it was run (U.S. EPA, 1987).

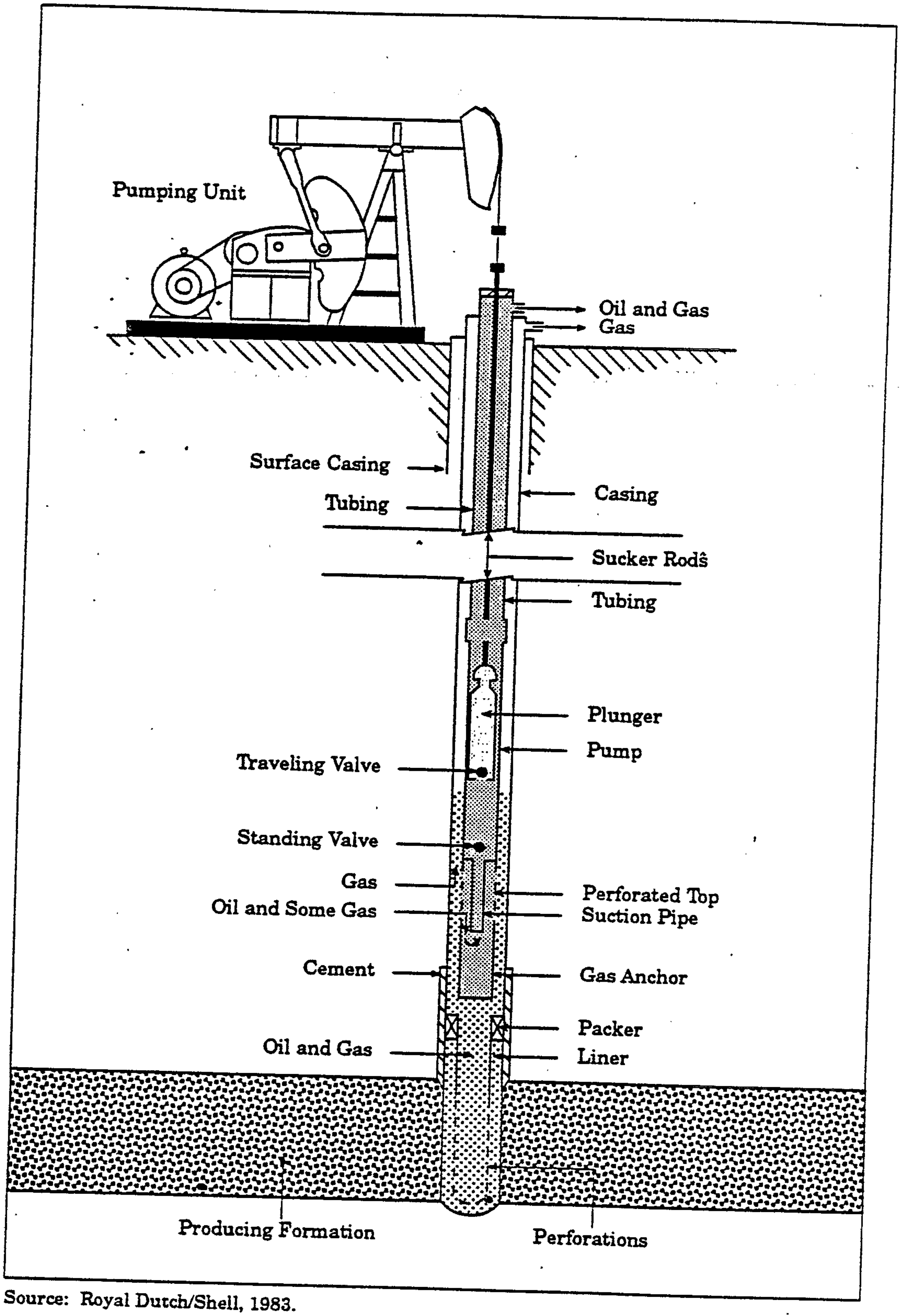
HOW OIL AND GAS ARE PRODUCED

Production operations generally include all activities associated with the recovery of oil and gas from geologic formations. They can be divided into activities associated with downhole operations and activities associated with surface operations. Downhole operations include primary secondary, and tertiary recovery methods, well workovers, and well stimulation activities. Activities associated with surface operations include oil/gas/water



Source: Royal Dutch/Shell, 1983.

Figure A-1. Rotary drilling rig.



Source: Royal Dutch/Shell, 1983.

Figure A-2. Cross section of a well pumping installation.

separation, fluid treatment, and disposal of produced water. The term "extraction" is commonly used to refer to activities associated with getting oil or gas to the surface; production includes both extraction and the surface operations involved in processing the materials extracted from the well. Production, as discussed in this report, is limited to the processing and storage that occurs at the well site. Transportation and further processing is not included in the scope of this report.

Downhole Operations

The initial production of oil or gas from the reservoir is called primary recovery. Natural pressure or artificial lift methods (surface or subsurface pumps and gas lifts) are used to bring the gas or oil out of the formation and to the surface (see Figure A-3). High-pressure gas can also be injected to lift the oil from the reservoir.

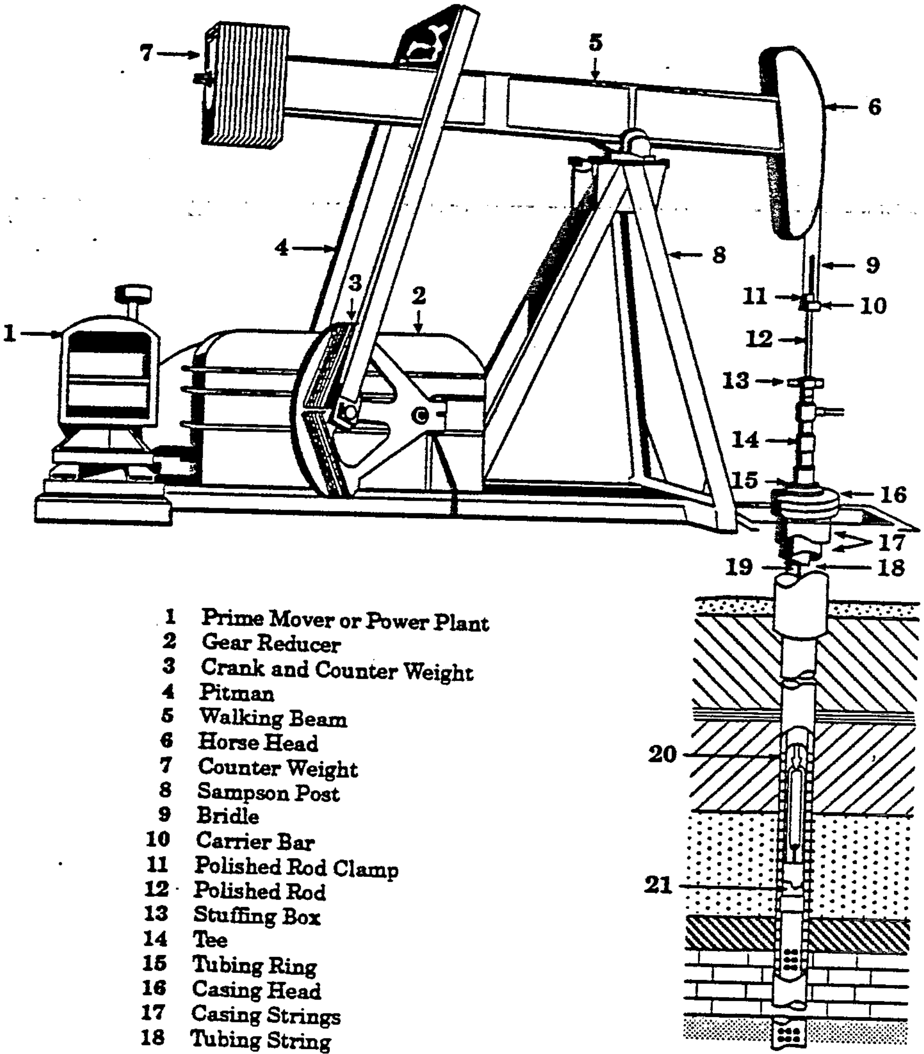
During the primary recovery stage, natural pressure in the reservoir may decline and artificial lift may be needed. One of three general types of pumps may be used: (1) pumps at the bottom of the hole run by a string of rods; (2) pumps at the bottom of the hole run by high-pressure liquids; and (3) bottom-hole centrifugal pumps (API, 1976).

The pumping unit includes a complete set of surface equipment that imparts an up-and-down motion to the sucker-rod string, which is connected the bottom-hole pump. Figure A-2 shows the parts of such as unit. Deep wells often require the long-stroke pumping provided by hydraulic units.

A stuffing box is used in a pumping well to pack or seal off the pressure inside the tubing so that liquid and gas cannot leak outside the polished rod. A stuffing box consists of flexible material or packing housed in a box which provides a method of compressing the packing. The packing material gradually wears out and must be replaced before it loses its effectiveness as a seal (API, 1976).

Primary recovery methods alone can produce oil and gas from most reservoirs, but over the life of the well production gradually decreases. Some form of secondary recovery will eventually be needed in nearly all wells. Secondary recovery methods inject gas or liquid into the reservoir to maintain pressure. The most frequent method is waterflooding, which involves injecting treated water (seawater, fresh water or produced water) into the formation through a separate well.

When secondary recovery methods are no longer adequate, the last portion of the oil that can be economically produced is recovered by tertiary methods. These include chemical, physical, and thermal methods or some combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery methods inject gases such as carbon dioxide and natural gas that combine with the oil. Thermal recovery methods include steam injection and *in situ* combustion (or "fire flooding"). The injected gases or fluids from secondary and tertiary recovery operations are



1	Prime Mover or Power Plant
2	Gear Reducer
3	Crank and Counter Weight
4	Pitman
5	Walking Beam
6	Horse Head
7	Counter Weight
8	Sampson Post
9	Bridle
10	Carrier Bar
11	Polished Rod Clamp
12	Polished Rod
13	Stuffing Box
14	Tee
15	Tubing Ring
16	Casing Head
17	Casing Strings
18	Tubing String
19	Sucker Rod
20	Fluid Level
21	Rod Pump

Source: API, 1976.

Figure A-3. Main parts of a pumping unit.

dissolved or mixed with the oil produced by the well and must be removed during surface production operations (U.S. EPA, 1987).

Workovers are another type of downhole production operation. Workovers are used to restore or increase production when downhole mechanical failures or blockages, such as sand or paraffin deposits have inhibited the flow of a well. Fluids circulated into the well for a workover must be compatible with the formation and must not adversely affect permeability. The workover fluid may be reclaimed or disposed of when the well is put back into production. Workover fluids are similar to completion fluids, which are special fluids used when the well is completed (ready for the production phase), to minimize formation damage and control potential problems such as H_2S corrosion.

Other chemicals are used periodically or continuously to inhibit corrosion, reduce friction, or simply keep the well flowing (U.S. EPA, 1987).

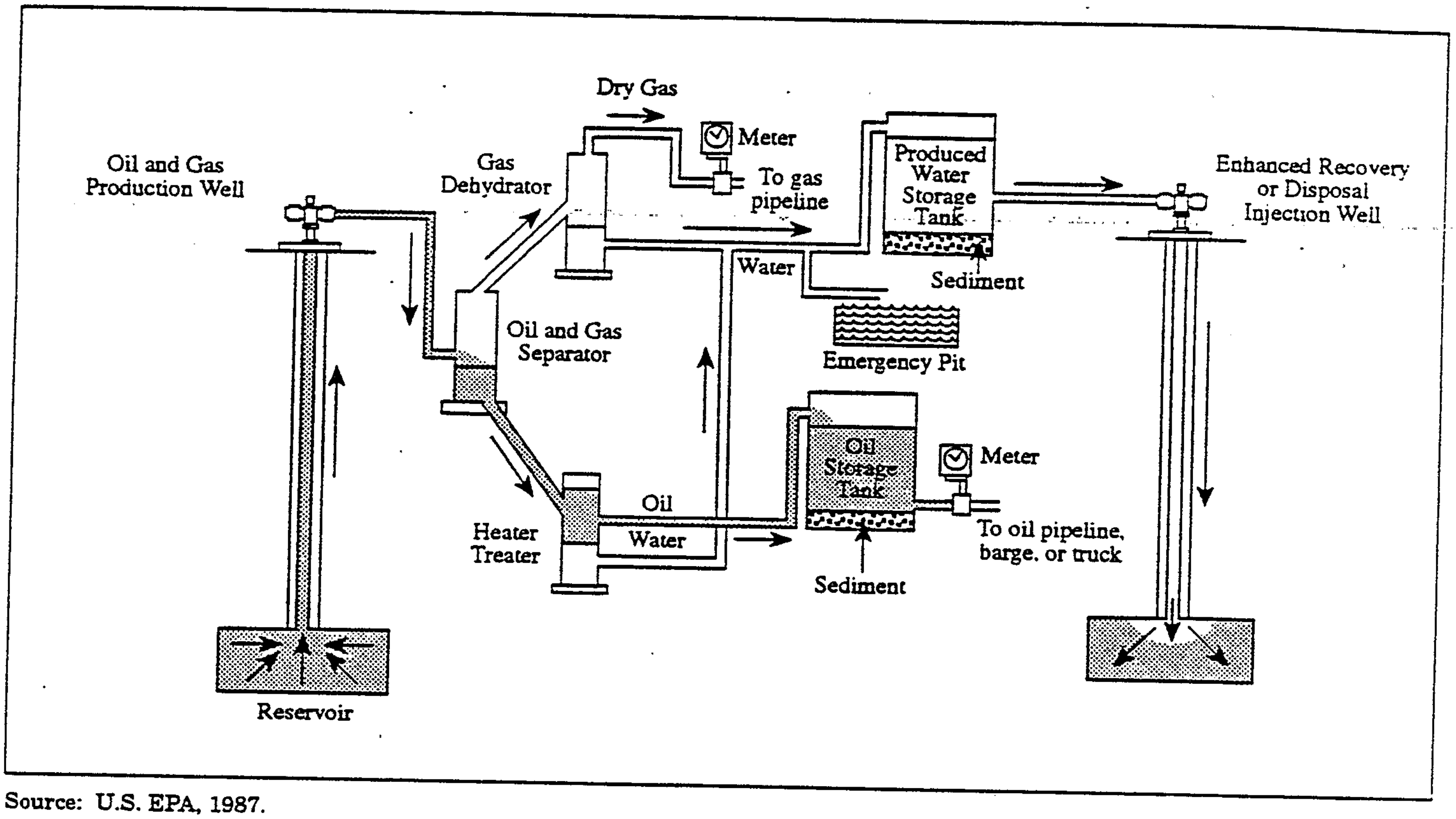
Surface Operations

As fluids are pumped to the surface, they are collected and treated to separate the various components (oil, gas, gas liquids, and water). Figure A-4 shows the separation process. These surface operations become more complex as secondary and tertiary recovery methods are employed. The ratio of water and other fluids to oil tends to increase as producing reservoirs are depleted. In new wells little or no water may be produced. The volume of water produced by stripper wells varies greatly. Stripper wells may produce more than 100 barrels of water for every barrel of oil, especially if waterflooding is used as a secondary recovery (U.S. EPA, 1987).

Separation involves the use of equipment to separate the gas, oil and water from each other. The actual separation may be accomplished in a single step or several steps depending on the relative amounts and the physical characteristics of the material which is delivered to the surface. Complete separation may require several stages involving different pressures, temperatures, and possibly additives if the material is delivered to the surface at a high pressure and the oil and gas are present in an emulsion.

After separation, the gas is transported by pipeline to a gas processing facility if the quantities from a specific well are adequate. If the quantities are inadequate, the gas is flared (burned). Gas processing facilities remove inerts (N_2, CO_2), hydrogen sulfide (H_2S), and liquids (oil and water) to produce pipeline quality gas which has a nominal heating value of 1000 BTU per cubic foot. Gas can also be re-injected into the well if necessary to help manage the reservoir or the production from the well.

Oil that is recovered from the separators at the well is placed in tanks and transported to a refinery for processing. This transportation is by pipeline if the quantities are adequate to justify installation of a pipeline or by truck if the production is small.



Source: U.S. EPA, 1987.

Figure A-4. Typical extraction operation showing separation of oil, gas, and water.

Water recovered from the separators at the well is placed in tanks or pools. This water will ultimately be reinjected into the producing formation, injected into a disposal well, or discharged. Reinjection into the producing formation and injection into a disposal well are the most common methods for water disposal; discharge is rarely used. Permits are usually required for these water disposition options.

The equipment used at the surface to control the well is called the well head. If high production or significant gas pressure is expected, the well head is usually built of cast or forged steel, and machined to a close fit. These sealed fittings prevent well fluids from blowing or leaking at the surface. Parts of the well head may be designed to hold pressures up to 20,000 lb per sq in (psi). Some well heads are just simple assemblies to support the weight of the tubing in the well, and may not be built to hold pressure. For stripper wells, or other low-production, low-pressure wells, a simple well head can be used as long as only small amounts of gas are produced with the oil (API, 1976).

High pressures or corrosive gases such as H_2S require well heads with special valves and control equipment to control the flow of oil and gas from the well. These are constructed of heavy metal and installed above the casing head or tubing head before the well is completed. This collection of valves is called a Christmas tree because of its shape and the large number of fittings branching out above the well head. The tree diverts fluids through alternative chokes (API, 1976).

Safety measures should be adequate to prevent high pressure wells from going out of control. Equipment is available that automatically shuts off production if there is damage to the wellhead or to automatic surface safety valves at the wellhead.

Simpler types of Christmas trees can be used on low pressure or pumping wells. Pressure gauges on the well head and Christmas tree measure the pressure in the casing and tubing. If the pressures under various operating conditions are known, better control can be maintained (API, 1976).

OVERVIEW OF THE INDUSTRY

The U.S. petroleum industry drilled its first oil well in 1859. Since that first well, the oil and gas industry has grown to be extremely complex and diverse. In 1990, approximately 869,887 wells in over 33 States were producing oil and gas in the United States. The oil and gas obtained from these wells is found at depths ranging from 30 feet to 30,000 feet below the earth's surface. The major U.S. areas of onshore production include the southwest (including California), the midwest, and Alaska, with lesser contributions from the Appalachians. Table A-1 lists production estimates for the oil and gas producing States. In 1990-1991, Texas led all States in oil and natural gas production, turning out 705 million barrels of oil and 6.3 trillion cubic feet of natural gas (Petroleum Independent, 1992). Figure A-5 shows U.S. oil and gas production by State. The bar graph in Figure A-6 shows distribution of States containing more than 70 percent of gas wells in the U.S. Some of these

Table A-1. 1991 Oil and 1990 Gas Production Estimates

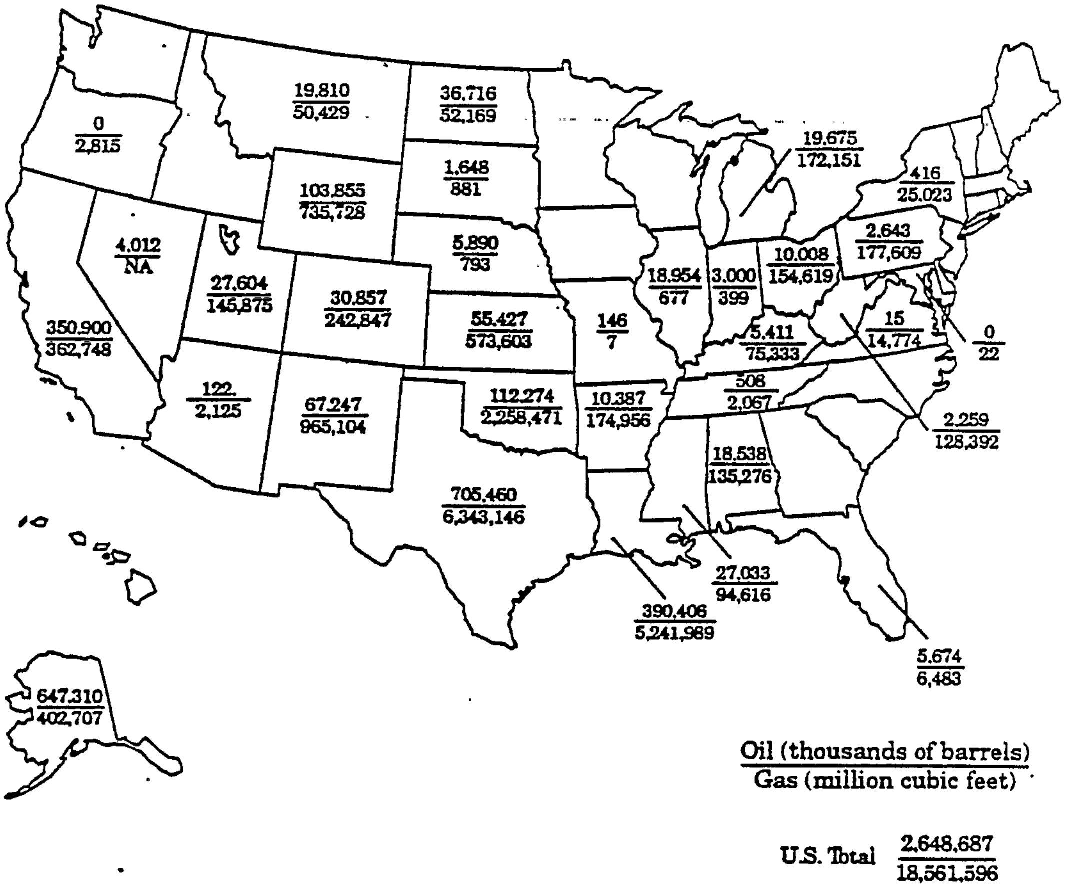
State	Number of Producing Oil Wells[a]	Oil Production (thousands of barrels)[b]	Number of Producing Gas Wells[a]	Gas Production (million cubic feet)[b]
Alabama	872	18,538	2,038	135,276
Alaska	1,466	647,310	109	402,907
Arizona	22	122	NA	2,125
Arkansas	7,265	10,387	3,460	174,956
California	43,375	350,900	1,169	362,748
Colorado	6,596	30,857	5,097	242,897
Florida	83	5,674	NA	6,483
Illinois	31,874	19,954	356	677
Indiana	7,506	3,000	1,311	399
Kansas	45,470	55,427	14,043	573,603
Kentucky	22,741	5,411	11,713	75,333
Louisiana	23,812	390,406	13,530	5,241,989
Maryland	0	0	NA	22
Michigan	4,570	19,675	1,438	172,151
Mississippi	2,168	27,033	629	94,616
Missouri	854	146	NA	7
Montana	3,854	19,810	2,428	50,429
Nebraska	1,440	5,890	NA	793
Nevada	46	4,012	NA	NA
New Mexico	18,546	67,247	19,537	965,104
New York	4,043	416	5,406	25,023
North Dakota	3,546	36,716	103	52,169
Ohio	30,089	10,008	34,697	154,619
Oklahoma	95,468	112,274	27,919	2,258,471
Oregon	0	0	NA	2,815
Pennsylvania	22,338	2,643	30,000	177,609
South Dakota	149	1,648	52	881
Tennessee	736	508	527	2,067
Texas	188,829	705,460	48,075	6,343,146
Utah	1,972	27,604	742	145,875
Virginia	25	15	819	14,774
West Virginia	15,950	2,143	37,000	178,000
Wyoming	11,397	103,855	2,431	735,728
Federal Waters	4,468	NA	3,591	NA
Other	25	NA	147	NA
U.S.	601,520	2,684,687	268,367	18,561,596

Combined Source: Petroleum Independent, September 1992, attributes the individual column sources to:

[a] World Oil.

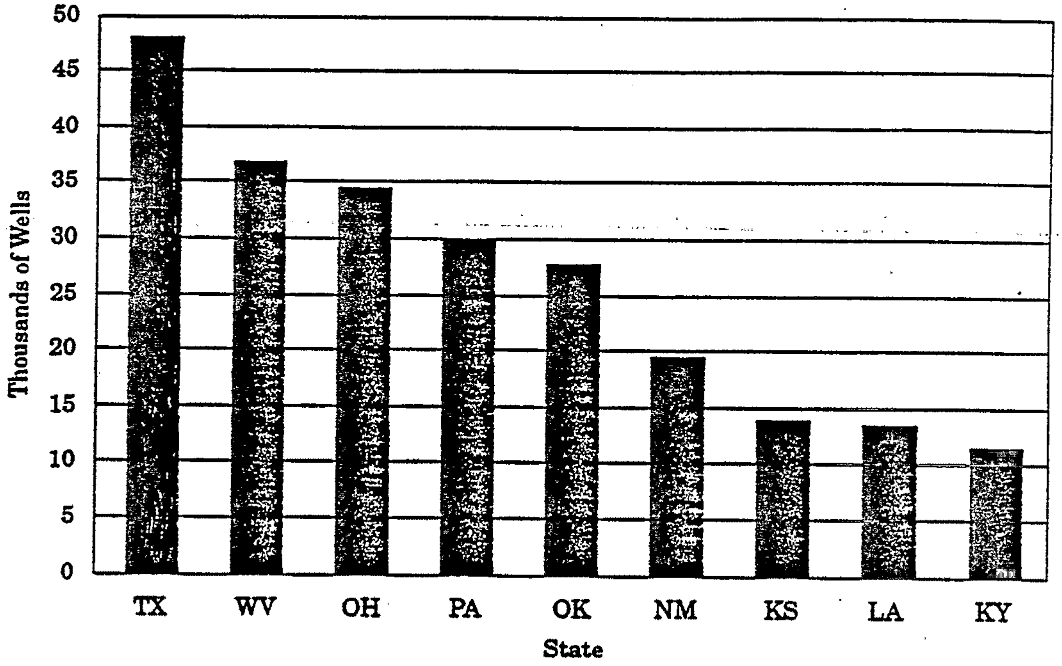
[b] Energy Information Administration.

–NA Not available.



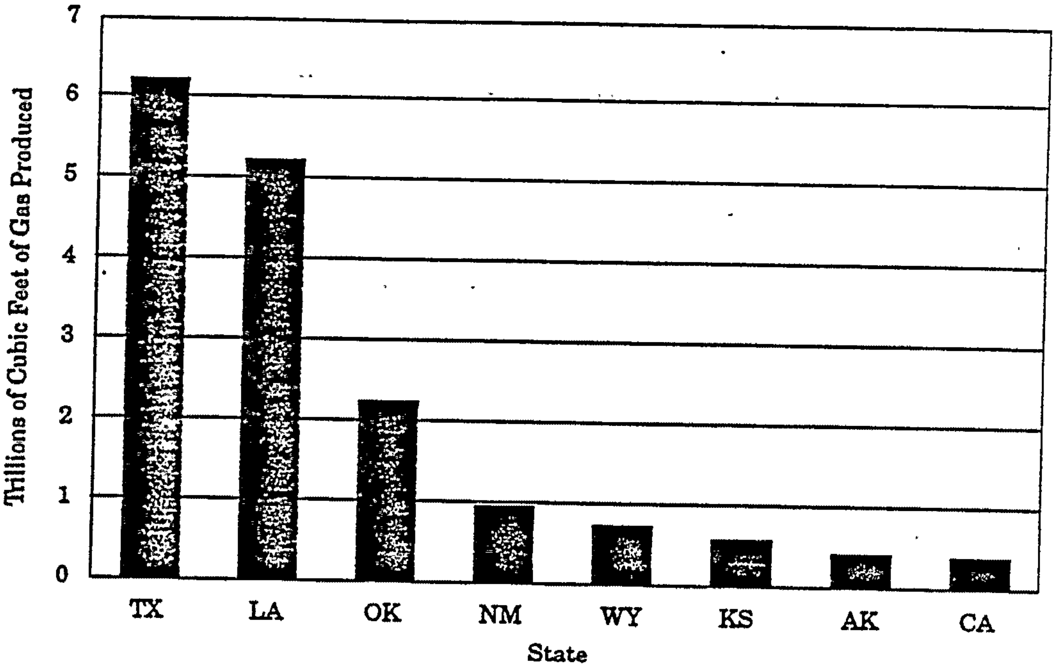
Combined Source: Petroleum Independent, September 1992, attributes the oil and gas sources to: World Oil Energy Information Administration.

Figure A-5. 1991 U.S. oil and gas production by State.



Source: World Oil (in Petroleum Independent, September 1992)

Figure A-6. States with the most producing gas wells in 1990.



Source: Energy Information Administration (in Petroleum Independent, September 1992).

Figure A-7. Gas production in 1990 from the top producing states.

States, however, are not the largest gas producers. Figure A-7 shows that Texas, Louisiana, Oklahoma, New Mexico, Wyoming, Kansas, Alaska, and California account for 92 percent of domestic gas production. Alaska, California, Louisiana, and Texas account for 78 percent of domestic oil production.

Principal Production Industry Groups

The industry can be divided into four groups. The first group consists of the major oil companies. These companies are highly vertically integrated, which means that they perform both "upstream" activities (oil exploration, development and production) and "downstream" activities (transportation, refining and marketing).

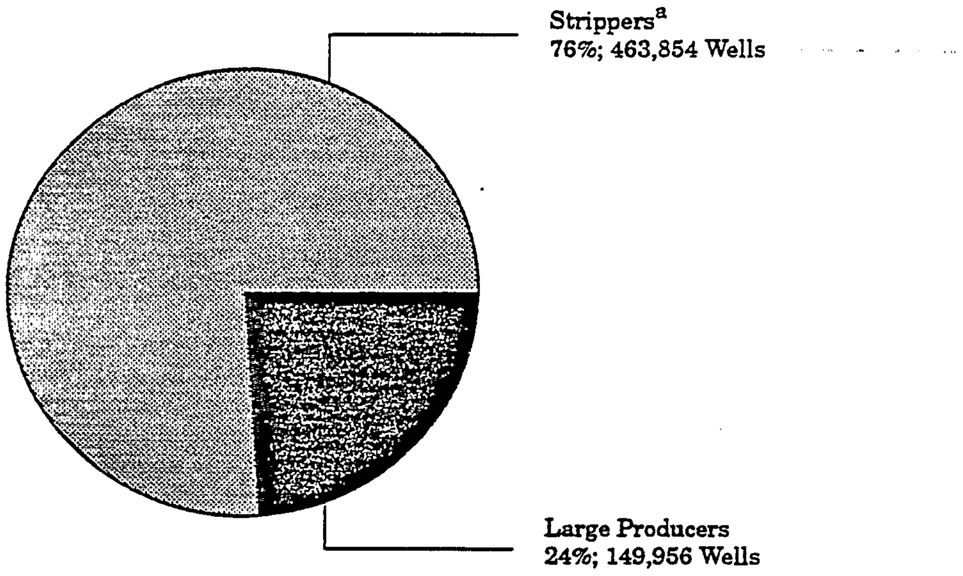
The second group is the large independents. These companies primarily explore, develop, and produce oil and gas, but do not perform downstream activities. Some large independents produce oil and gas only, while others provide such additional services as contract drilling and pipeline operations.

The third group is the small independents. Little information is available that would characterize this group quantitatively. However, small independents are known to have fewer wells and/or lower production wells. The lower operating expenses of small independents makes it more affordable to continue producing small quantities from low volume wells.

The fourth group consists of companies that provide a variety of specialized services to the oil and gas drilling rigs and platforms, such as designing, manufacturing, and installing specialized hardware. They also provide geophysical support, drilling mud, and logging services.

Diversity of Production

Production from individual wells varies greatly from a high of 11,500 barrels per day to less than 10 barrels per day. As shown in Figure A-8, over 70 percent of U.S. oil wells are "stripper" wells. The definition of a stripper well varies from State to State. However, these wells are generally defined as wells that produce 10 barrels of oil per day or less, or 100 thousand cubic feet (mcf) of gas per day or less. In 1990, 463,854 stripper wells existed and produced a total of 383,197,000 barrels of oil (NSWA, 1991). Stripper well production is shown in Table A-2. Figure A-9 shows that stripper wells produced 14 percent of the 2,684,687,000 barrels of oil produced in the United States in 1990 (U.S. EIA, 1991; U.S. EIA, 1987). Figure A-10 shows the proportion of stripper wells in the 10 States with the largest numbers of wells overall. In all 10 States, stripper wells comprised more 50 percent of producing wells. However, Figure A-11 demonstrates that in the 10 top oil producing States, oil from stripper wells is relatively low in volume. These wells typically are near depletion of recoverable natural resources and produce only a small quantity of oil or gas.



[a] Strippers are defined as those producing 10 barrels a day or less.

Source: Interstate Oil and Gas Compact Commission and National Stripper Well Association.

Figure A-8. Number of producing oil wells in the U.S. in 1990.

Table A-2. 1990 Oil Production from Stripper Wells by State

Location	Number of Producing Wells[a]	Number of Producing Stripper[c] Wells	Percentage of Producing Wells Which Are Stripper Wells[*]	Amount of Crude Oil Produced (thousands of barrels)[b]
Alabama	872	514	58%	18,538
Alaska	1,466	0	0%	647,310
Arizona	22	12	55%	122
Arkansas	7,265	7,290	NA*	10,387
California	43,375	26,128	60%	350,900
Colorado	6,596	5,234	79%	30,857
Florida	83	0	0%	5,674
Illinois	31,874	33,700	NA*	19,954
Indiana	7,506	5,764	77%	3,000
Kansas	45,470	45,227	99%	55,427
Kentucky	22,741	19,330	85%	5,411
Louisiana	23,812	17,695	74%	390,406
Michigan	4,570	3,967	87%	19,675
Mississippi	2,168	615	28%	27,033
Missouri	854	375	44%	146
Montana	3,854	3084	80%	19,810
Nebraska	1,440	1,269	88%	5,890
Nevada	46	0	0%	4,012
New Mexico	18,546	15,261	82%	67,247
New York	4,043	3,748	93%	416
North Dakota	3,546	1,205	34%	36,716
Ohio	30,089	29,576	98%	10,008
Oklahoma	95,468	73,345	77%	112,274
Pennsylvania	22,338	21,800	98%	2,643
South Dakota	149	26	17%	1,648
Tennessee	736	923	NA*	508
Texas	188,829	127,790	68%	705,460
Utah	1,972	1,026	52%	27,604
Virginia	25	22	88%	15
West Virginia	15,950	15,975	NA	2,143
Wyoming	11,397	2,953	26%	103,855
U.S.	601,520	463,854	77%	2,684,687

Combined Source: Petroleum Independent, September 1992, attributes the individual column sources to:

[a] World Oil.

[b] Energy Information Administration.

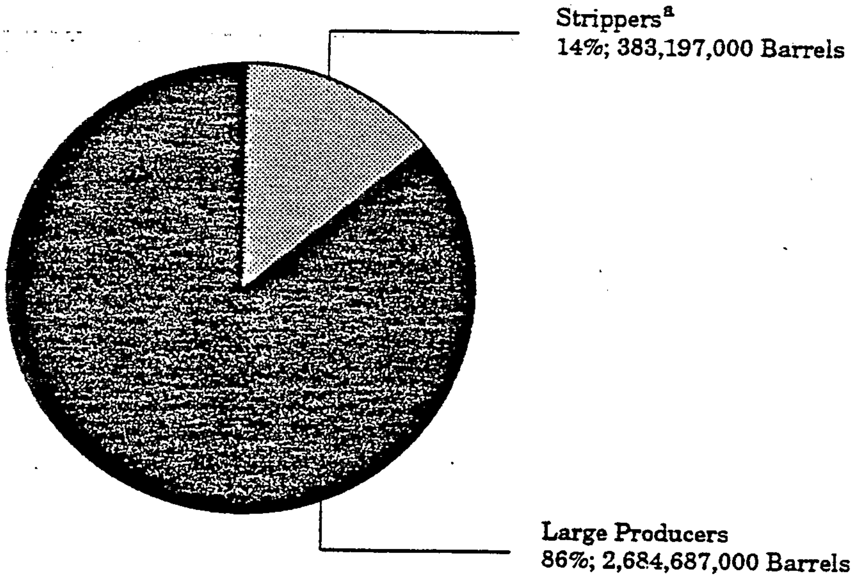
[c] Interstate Oil and Gas Compact Commission and National Stripper Well Association.

*Petroleum Independent warns "[number of producing stripper wells]-data cannot be compared to "Producing Oil Wells" table due to different sources and technology."

NA Unable to calculate.

Table A-2. 1990 Oil Production from Stripper Wells by State (continued)

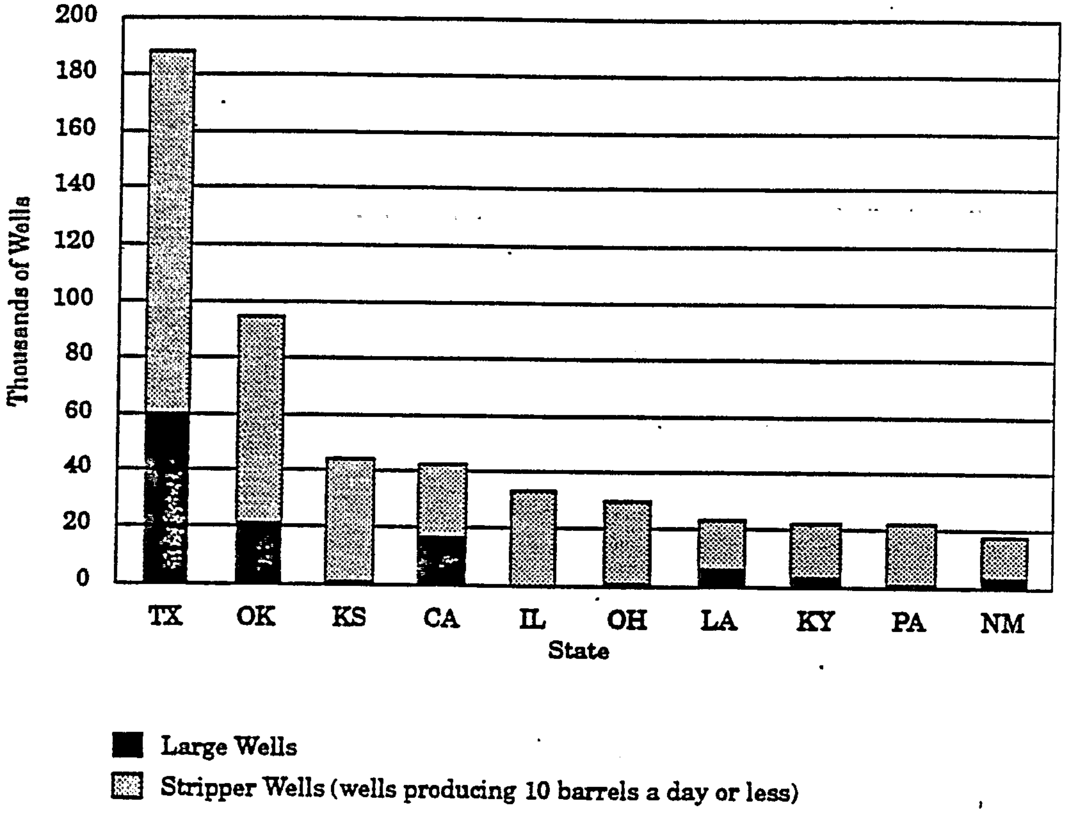
Amount of Crude Oil Produced from Stripper Wells (thousands of barrels)[c]	Percentage of Crude Oil Produced from Stripper Wells
1,486	8%
0	0%
26	21%
5,693	55%
36,405	10%
5,698	19%
0	0%
18,520	93%
3,002	NA*
40,873	74%
4,338	80%
7,154	2%
4,599	23%
802	3%
120	82%
2,449	12%
2,011	34%
0	0%
14,296	21%
383	92%
2,053	6%
7,271	73%
78,599	70%
2,622	99%
64	4%
419	83%
135,850	19%
1,035	4%
12	80%
2,122	99%
5,297	5%
389,197	14%



[a] Strippers are defined as those producing 10 barrels a day or less.

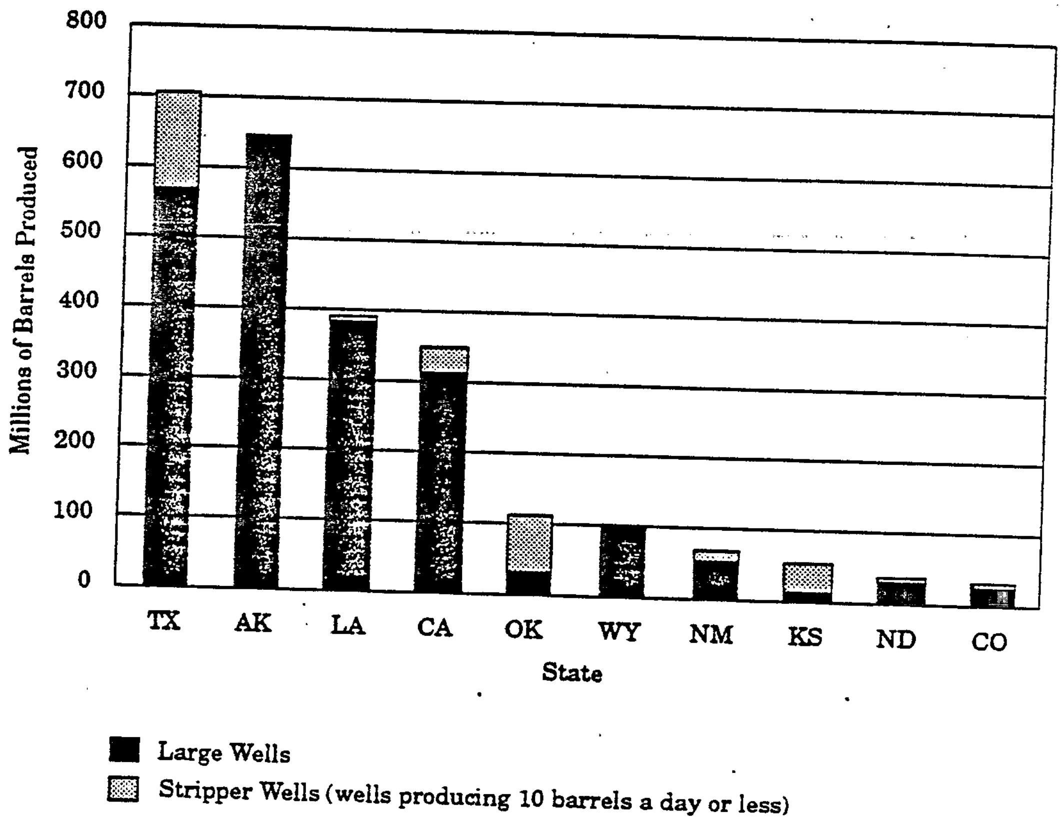
Source: Interstate Oil and Gas Compact Commission and National Stripper Well Association.

Figure A-9. 1990 U.S. oil production.



Source: World Oil (in Petroleum Independent, September 1992).

Figure A-10. States with the largest number of producing oil wells in 1990.



Source: World Oil (in Petroleum Independent, September 1992).

Figure A-11. Oil production in 1990 from the top producing states.

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APPENDIX B

SUBJECTS OF STATE H_2S REGULATIONS AND GUIDELINES

Table B-1. Subjects of State H_2S Regulations and Guidelines

Regulations and Guidelines	Oklahoma	Texas	Michigan	California*
Characteristics and Effects of H_2S (including emergency rescue, resuscitators, effects on metal and artificial respiration)	NA	●	●	●
Initial Testing	●	NA	●	●
Periodic Gas Analyses	●	NA	NA	NA
Nuisance Odors	●	NA	NJ	NA
Guidelines for Safe Drilling Operations				
A. Location Requirements	●	●	●	●
B. Drilling Equipment (Including blowout preventer, controls, piping and accessories, etc.)	●	●	●	●
C. Monitoring Equipment (including alarm systems and gas detection equipment)	●	●	●	●
D. Personal Protective Equipment (including all personnel, breathing apparatus, equipment specs., etc.)	●	●	●	●
E. Employee Physical Requirements	NA	●	NA	NA
F. Training Requirements	●	●	●	NA
G. Drills and Orientations	●	●	●	●
H. Maintenance of Equipment	●	●	●	●
I. Warning Systems	●	●	●	●
J. Evacuation	●	●	●	●
Guidelines for Safe Production Operations				
A. Applicability	NA	●	●	NA
B. General Provisions	NA	●	●	NA
1. Concentration Determination	●	●	●	NA
2. Radius of Evacuation (ROE)	●	●	●	●
3. Escape Rate Volume Determinators	●	●	●	NA
4. Storage Tank Provisions	●	●	●	NA
5. . . . ppm ROE in excess of . . . feet	●	●	●	●
6. Implementation	●	●	●	NA
7. Control and Safety Equipment	●	●	●	●
8. Contingency Plan	●	●	●	●
9. Training	●	●	●	NA
10. Injection Provision	●	●	●	NA
11. Certificate of Compliance Provision	●	●	●	NA
12. Accident Notification	●	●	●	●

NA Not available in reviewed literature.
● The subject was identified under the State's H_2S regulations or guidelines.
A Rule 36 references API RP19.
NJ Not under Congressional jurisdiction.
MMIOSH Required by Michigan OSHA.
*CA grants the supervisor of the Oil and Gas Division discretionary authority to control H_2S releases.

APPENDIX C

ATMOSPHERIC DISPERSION CALCULATIONS FOR H_2S RELEASES FROM OIL AND GAS EXTRACTION FACILITIES

APPENDIX C

ATMOSPHERIC DISPERSION CALCULATIONS FOR H_2S RELEASES FROM OIL AND GAS EXTRACTION FACILITIES

INTRODUCTION

The purpose of this appendix is to provide supporting details for the analyses of atmospheric dispersion of H_2S conducted for this report. In Chapter III, computer models were used, together with information on published studies of sour gas releases, to examine the range of predictions of the distances of concern for scenarios of H_2S releases from wellheads or pipelines. The inputs to the analyses are reviewed, and the outputs of three sample calculations for two of the scenarios are described. Outputs for a horizontal wellhead release are described for calculations using the SLAB and SAPLUME models. The output for a vertical wellhead release using the DEGADIS model is also described.

SUMMARY INPUT AND OUTPUT DATA

Summary data for the wellhead blowout and pipe rupture scenarios are presented in Tables C-1 and C-2, respectively. As described in Chapter III, analyses for wellhead blowouts were conducted using the SLAB, DEGADIS, and SAPLUME models. Analyses of the pipe rupture scenarios were conducted using the SACRUNCH and SAPLUME models.

The wellhead blowout scenarios in Chapter III result from various assumed flow rates as presented again in Table C-1. The following discussion presents some justification for the choice of these flow rates. Flow rates are functions of such factors as rock permeabilities, gas properties, depth, and tube and casing diameters. In practice, there are large variabilities in these parameters. One measure of the potential rate of flow from a well is the Calculated Absolute Open Flow Rate (CAOF), which is the rate of flow of gas into the well bore when the pressure is atmospheric. A sample of 15 wells in western Wyoming had CAOFs with a geometrical mean of 4.7×10^6 standard cubic feet per day (scf/d) or 1.3×10^5 cubic meters per day (m^3/d) (Layton et al., 1983). The 95 percent confidence interval spanned the range from 2.1×10^5 scf/d (5.9×10^3 m^3/d) to 10^8 scf/d (2.8×10^6 m^3/d). Alp et al. (1990) considered CAOFs of between 5×10^4 and 5×10^6 m^3/d as representative of wells in Alberta and chose 10^6 m^3/d as representative for the purposes of risk analysis. The Quest report (1992) considered CAOFs in the range 2.2×10^5 to 7.3×10^6 m^3/d for a system of wells in southwestern Wyoming. The actual flow rates out of a ruptured well will be less than the CAOF because of frictional effects in the pipework. By contrast, the Quest report and Layton et al. use the CAOF as a conservative estimate of flow rate. Based on the above discussions, a flow rate of 2×10^7 scf/d was chosen for representative calculations, with a flow rate of 10^8 scf/d being taken as an example of a very high flow rate.

TABLE C-1

SUMMARY OF INPUT AND OUTPUT DATA WELLHEAD BLOWOUT SCENARIOS

SCENARIO[a]	A	B	C	D	D(E)*
INPUTS					
Flow rate (m^3/d)	$6x10^5$	$6x10^5$	$6x10^5$	$6x10^5$	$3x10^6$
Vol. % H_2S	7.5	27	15	30	30
Density[b] @ 0°C (kg/m^3)	0.862	1.293	1.038	1.128	1.128
Release temperature (°C)	0	0	0	0	0
Total release rate (kg/s)	5.99	8.98	7.21	7.83	39.2
Release rate of H_2S (kg/s)	0.79	2.85	1.58	3.17	15.8
Ambient temperature (°C)	5	5	5	5	5
Relative humidity (%)	75	75	75	75	75
Atmospheric stability category	F	F	F	F	F
Windspeed (m/s)	1.5	1.5	1.5	1.5	1.5
Surface roughness length (m)	0.1	0.1	0.1	0.1	0.1
Effective area of release (m_2)	0.02	0.02	0.02	0.02	0.1
OUTPUTS: HORIZONTAL RELEASE					
SLAB:					
Distance to:					
LC_{01}(m)	700	2,800	1,500	2,900	7,000
ERPG-2(m)	2,800	7,000	4,700	7,000	>10,000
SAPLUME:					
Distance to:					
LC_{01} (m)	1,000	2,700	1,500	3,000	>10,000
ERPG-2(m)	3,100	10,000	5,700	10,000	>10,000
OUTPUTS: VERTICAL RELEASE					
SLAB:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0
DEGADIS:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0
SAPLUME:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0

[a] Scenarios from Table III-7.

[b] For comparison, density of air @ 0°C=1.293 kg/m^3.

* E=Extreme Case.

TABLE C-2

PIPE RUPTURE SCENARIOS
INPUTS AND OUTPUTS (SADENZ MODEL)

Parameters/Scenario	Composition A[a], rupture of 4" diameter pipeline[b]	Composition D[a], rupture of 16" diameter pipeline[c]
INPUTS		
Total mass released (kg)[d]	640	31,000
Total mass of H_2S (kg)	84	12,500
Duration of release (s)[d]	16	310
Density @ 0°C (kg/m^3)	0.862	1.128
Release temperature (°C)	0 (32 °F)	0 (32 °F)
Ambient temperature (°C)	5 (41 °F)	5 (41 °F)
Relative humidity (%)	75	75
Atmospheric stability category	F	F
Windspeed (m/s)	1.5	1.5
Surface roughness length(m)	0.1	0.1
OUTPUTS		
Distance to:		
LC_{01} (m)	600	4,300
ERPG-2 (m)	750	5,600

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[a] Composition from Table III-5.
[b] Spacing between emergency shutdown valves is 1,000 m.
[c] Spacing between emergency shutdown valves is 3,000 m.
[d] From Figure III-22.

Table C-1 also presents values for the effective area of release. These values are derived by dividing the volumetric release rate by the velocity of release and were not the bases for the release scenarios. As stated in Chapter III, the velocity of release was assumed to be "choked," or limited, to sonic velocity (approximately 330 m/s) as a result of the high initial gas pressure.

The temperature of the gas in a well prior to expansion to atmospheric pressure through a rupture depends on the depth of the gas reservoir. The amount of cooling that results from expansion to atmospheric pressure as a result of release depends on the initial pressure and the composition. Alp et al. (1990) assume a representative release temperature of 15°C (288 K) at atmospheric pressure. In the Quest report, the authors assume a reservoir temperature of 60°C and calculate expansion temperatures of between -9°C and 3°C. The calculated results of wellhead blowout and pipeline rupture scenarios in this study are based on a representative release temperature of 0°C. This temperature is below the assumed ambient temperature of 5°C.

Atmospheric conditions characterized by low turbulence and low wind speed provide for decreased dilution of a released chemical with the surrounding air. Thus, these conditions are directionally conservative in terms of potential exposure to accidental releases. Atmospheric thermal stability, impacted by the difference between surface and air temperatures, is often described by Pasquill atmospheric stability categories. These categories range from high turbulence (A) through low turbulence (F). The "F" category is typical of still, nighttime conditions (AIChE, 1989). This category was chosen for the calculations conducted to conservatively evaluate the wellhead blowout and pipeline rupture scenarios. Wind speeds of less than 2 m/s are considered low and create little turbulence. The calculations used in this study's analyses assume a wind speed of 1.5 m/s to conservatively simulate nonturbulent conditions. Actual conditions of A - D stability and higher wind speeds will cause more rapid dilution of an accidental release and will result in a decreased affected distance. The assumption that conditions of low wind speed and stable atmospheric conditions exist uniformly for extended distances also provides conservatism to the analyses.

Terrain is another factor that may influence atmospheric dispersion of a release. The surface roughness length is a measure of the "roughness" of the terrain. Roughness is a function of the type of terrain and the presence of such features as trees and buildings. The models in this study assume that the study of the behavior of dense gas flow around obstacles and through rough terrain is controversial and is an area where further research is needed. Rough terrain will cause more turbulence to atmospheric flows above it than smooth terrain. The value of surface roughness length, 0.1 m, used in the calculated dispersion predictions, is considered to be an intermediate roughness length and typical of highly vegetated rural terrain. It should be noted that lower, more conservative values would be more appropriate in flat, barren terrain.

SAMPLE SLAB CALCULATIONS

SLAB Input

The following illustrates how the input is prepared for SLAB, using composition D from Table III-5 as an example. The SLAB input is displayed on Table C-3. The SLAB users' manual provides further guidance (Ermak, 1989).

Line 1: IDSPL is the spill source type. For an evaporating pool, IDSPL =1. For a horizontal jet release IDSPL=2. For a vertical jet release IDSPL=3. For a puff, IDSPL = 4. For the present example, the release is assumed to be horizontal, IDSPL=2.

Line 2: NCALC is a numerical substep parameter. The code developer recommends using NCALC=1. However, NCALC can be increased if numerical stability problems are encountered.

Line 3: WMS is the molecular weight of the wellhead gas in kg/gmole. From Table III-6, it is 0.0252 kg/gmol (from 25.2 g/gmol). Note, however, that the value given in Table C-3 is 0.0289 kg/gmol, for the following reason. Initially, the dilution of the plume is dominated by entrainment caused by its high momentum (its initial velocity equals that of sound). There is considerable dilution in this early phase and, by the time it is over, the density of the plume is only slightly less than that of the surrounding atmosphere. Work on marginally buoyant plumes shows that they are not likely to lift off the ground (Briggs, 1973). However, SLAB runs with WMS = 0.0252 kg/gmol show predicted plume rise that continues to a height of over 100 m. This is regarded as physically unrealistic and the computer model is "fooled" into ignoring plume rise by setting WMS equal to the effective molecular weight of air which is 28.9 g/gmol (0.0 289 kg/gmol). As noted above, this is thought to be physically realistic. The results predicted in this way will be conservative if plume rise does in fact take place.

Line 4: CPS is the vapor heat capacity at constant pressure. Similar to the above molecular weight calculation, the gas mixture vapor heat capacity is calculated by summing the product of the constituents' mole percent and vapor heat capacity. For composition D it is approximately 1,500 J/kg/K.

Line 5: TBP is the boiling point of the released material. For a pure vapor release, SLAB does not in fact use this quantity, which has been arbitrarily set equal to the boiling point of methane, 111.5K.

Line 6: CMEDO is the liquid mass fraction in the initial release and is set to zero because the release is pure vapor.

Lines 7, 8: DHE=509,880 (J/kg) and CPSL=3,349 (J/kg/K) are the heat of vaporization and the liquid specific heat for methane. Their values are taken from Table 2 of the SLAB

Users' Guide. When the released material is pure vapor, as it is in the present case, and the temperature of the cloud does not drop below the boiling point, these values are adequate because the liquid properties will not be used in the SLAB calculation. However, a value for all SLAB input properties must be specified whether they are used or not.

Line 9: RHOSL is the liquid density of the released material. This is another quantity that is not used in the calculations. It has been set equal to the density of water (1,000 kg/m^3).

Lines 10,11: SPB and SPC are parameters that go into the saturated vapor pressure formula:

$$P_s = P_a * \exp[SPA - SPB/(T + SPC)],$$

where P_s is the saturated vapor pressure, P_a is the ambient pressure (1.01×10^5 N/m^2), SPA is defined in the code and T is the local cloud temperature. Table 2 of the SLAB Users' Guide contains some values of SPB and SPC, but not for the mixture modeled here. When these values are unknown, the Users' Guide recommends default values of SPB = -1 and SPC = 0. The code then uses the Clapeyron equation to define the value of SPB. When the released material is pure vapor, as it is in the present case, and the temperature of the cloud does not drop below the boiling point, this default is adequate because the saturation pressure will not be used in the SLAB calculation. However, a value for all SLAB input properties must be specified whether they are used or not.

Lines 12-17: These lines specify the spill parameters. TS is the temperature of the released material, taken to be 273K. QS is the rate of release, estimated at 20 million scfd (7.69 kg/s). AS is the effective area of the release, 1.93×10^{-2} m^2, obtained by dividing the volumetric flow rate by the speed of sound (340 m/s). TSD is the duration of the release, 3,600.s, the assumed duration of release for a wellhead blowout. QTIS is zero except when modeling an instantaneous puff release. Finally, HS is the height of the release, arbitrarily taken to be 5 m (close to the ground).

Line 18: TAV is the concentration averaging time. This is set equal to 3,600 to be consistent with the exposure time of concern.

Line 19: XFFM is the maximum downwind extent of the calculation. A value of 10 km is used in order to obtain cloud concentration results at large distances away from the release. It is set to 2×10^4 m, which should be enough to ensure that any results of interest lie within this distance.

Lines 20-23: ZP(I) allows the user to specify up to four heights at which the concentration is calculated as a function of downwind distance. ZP(1) is set to 1.6 m (approximate head elevation above grade). The remaining ZP(I)s are zero, which means that SLAB only considers the first height.

Lines 24-29: These lines specify the meteorological conditions. ZO is the surface roughness length, which is set to 0.1 m, depicting a relatively smooth surface. ZA is the height at which the windspeed is measured (10 m). UA is the windspeed at height ZA (1.5 m/s). TA is the ambient temperature (273K). RH is the relative humidity (75%, chosen as being typical of Category F weather conditions). Finally, STAB is the stability class (F=stable). The weather conditions (Category F with a low windspeed of 1.5 m/s) have been chosen to simulate unfavorable (close to worst case) conditions.

Line 30: TER is the end of file designator. TER < 0 terminates the run.

SLAB Output

A partial SLAB output corresponding to the inputs of Table C-3 is given in Table C-4. The interpretation is as follows. The first column gives the downwind distance, x. The second column gives the time at which the maximum concentration arrives at x and the third gives the duration of cloud passage. As can be seen, the duration of passage remains equal to the duration of release until the cloud has traveled several kilometers downwind. The fourth column gives the approximate half-width of the plume, bbc. The remaining six columns give the average concentration (volume fraction) at a height of 1.6 m (as chosen in the SLAB input) for six off-axis distances that are multiples of bbc, 0.5, 1.0, 1.5, etc. The predicted concentrations are zero close in because the plume was arbitrarily released at a height of 5 m. As the plume broadens, the concentrations at height 5 m rise above zero to a maximum at about 25 m to 30 m downwind and then begin to decline as the plume dilutes further.

The effective ERPG-2 is 100 ppm and the effective LC_{01} is about 4.7×10^5 ppb. These number values are derived as follows: the ERPG-2 for pure H_2S for an exposure time of 1 hour is 3×10^4 ppb. The volume concentration of H_2S in composition D is 30 percent (see Table III-5). Therefore, the overall concentration of the total released material when the H_2S in it is at 3×10^4 ppb is $30/0.3 = 1 \times 10^5$ ppb. Similarly, the LC_{01} for pure H_2S is 1.4×10^5 ppb for an exposure time of 1 hour (see Chapter III). Therefore, the effective LC_{01} for the plume is $140/0.3 = 4.7 \times 10^5$ ppb. As explained in Chapter III, the ERPG-2 is regarded as a threshold at which emergency response might be necessary and the LC_{01} is an approximate threshold for the occurrence of fatalities among the affected population. Reading down the column headed "y/bbc=0," the concentrations first fall below 4.7×10^5 ppb (= a volume fraction of 4.7×10^{-4}) at a distance of about 3 km and below 1×10^5 ppb (= a volume fraction of 1.0×10^{-4}) at a distance of about 7 km.

SAMPLE DEGADIS CALCULATIONS

DEGADIS Input

Table C-5 displays the DEGADIS input for the same case as was prepared for SLAB in Table C-3 except that DEGADIS can only simulate a vertical jet release. The chosen values for most of the parameters have already been explained in the section on SLAB.

Lines 1-4 allow the user to input up to four lines of title.

Line 5 requires the windspeed (1.5 m/s) and the height at which the windspeed is measured (10 m).

Line 6 gives the surface roughness length (0.1 m).

Line 7 requires the parameter INDVEL, the atmospheric stability category (F=6) and the Monin-Obukhov length RML. For INDVEL=1 (the present case) the model calculates RML from the stability category and the surface roughness length, so the user does not need to specify a value for RML.

Line 8 requires the ambient temperature (273K), the ambient pressure (1 atmosphere) and the relative humidity (75%).

Line 9 gives the surface temperature, which is here set equal to the ambient temperature (273K).

Line 10 is a name for the released gas, in this case CPD for ComPosition D.

Line 11 is the molecular weight, 25.2.

Line 12 is the averaging time, taken to be equal to the duration of release, 3,600 s. It is used to calculate the increase in the effective width of the plume as a function of exposure time.

Line 13 is the temperature of the released gas, 273K.

Line 14 contains the upper level of concern (470 ppm, expressed as a volume fraction), the lower level of concern (100 ppm) and the height at which the concentrations are calculated (1.6 m).

Line 15 contains first a variable INDHT=0, meaning that heat transfer from the ground is not included, which does not matter here because the plume, air, and ground all have the same temperature. The second entry is the specific heat of the released gas at constant pressure (1,500 J/kg/K). The third entry, CPP=0, indicates that an approximation was made in which the specific heat does not vary with temperature.

Line 16 is a parameter "NDEN" that is used to specify the density profile of the released material. For NDEN=0, the release is assumed to be an ideal gas with specific heat at constant pressure 1500J/kg/K. Water condensation effects are taken into account.

Line 17 is the mass rate of release, 7.69 kg/s.

Table C-3. SLAB Input - Horizonal Wellhead Release

Value	Parameter	Line No.
2 (horizontal), 3 (vertical)	IDSPL	1
1	NCALC	2
0.0289	WMS	3
1500.	CPS	4
111.50	TBP	5
0.0	CMEDO	6
509,880.	DHE	7
3,349.	CPSL	8
1,000.	RHOSL	9
-1.0	SPB	10
0.0	SPC	11
273.	TS	12
7.69	QS	13
$1.93x10^{-2}$	AS	14
3,600.	TSD	15
0.	QTIS	16
5.	HS	17
3,600.	TAV	18
20,000.	XFFM	19
1.6	ZP(1)	20
0.	ZP(2)	21
0.	ZP(3)	22
0.	ZP(4)	23
0.1	ZO	24
10.	ZA	25
1.5	UA	26
273.	TA	27
75.	RH	28
F	STAB	29
-1.	TER	30

Table C-4. Partial SLAB Output

Time Averaged (TAV = 3,600 s) Volume Concentration: Concentration in the z = 1.60 Plane.

Downwind Distance x (m)	Time of Max Conc (s)	Cloud Duration (s)	Effective Half Width bbc (m)	Average Concentration (Volume Fraction) at (x,y,z), y/bbc = 0.0	0.5	1.0	1.5	2.0	2.5
1.00	1.80×10^{3}	3.60×10^{3}	6.95×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.02	1.80×10^{3}	3.60×10^{3}	7.73×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.05	1.80×10^{3}	3.60×10^{3}	8.71×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.08	1.80×10^{3}	3.60×10^{3}	9.92×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.13	1.80×10^{3}	3.60×10^{3}	1.14×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.18	1.80×10^{3}	3.60×10^{3}	1.32×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.24	1.80×10^{3}	3.60×10^{3}	1.54×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.32	1.80×10^{3}	3.60×10^{3}	1.81×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.41	1.80×10^{3}	3.60×10^{3}	2.14×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.52	1.80×10^{3}	3.60×10^{3}	2.54×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.66	1.80×10^{3}	3.60×10^{3}	3.03×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.84	1.80×10^{3}	3.60×10^{3}	3.63×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
2.05	1.80×10^{3}	3.60×10^{3}	4.36×10^{-1}	8.35×10^{-41}	5.76×10^{-41}	1.88×10^{-41}	2.84×10^{-42}	1.93×10^{-43}	5.61×10^{-45}
2.31	1.80×10^{3}	3.60×10^{3}	5.24×10^{-1}	1.18×10^{-28}	8.13×10^{-29}	2.65×10^{-29}	4.02×10^{-30}	2.79×10^{-31}	8.76×10^{-33}
2.63	1.80×10^{3}	3.60×10^{3}	6.31×10^{-1}	3.14×10^{-20}	2.16×10^{-20}	7.03×10^{-21}	1.07×10^{-21}	7.54×10^{-23}	2.42×10^{-24}
3.01	1.80×10^{3}	3.60×10^{3}	7.61×10^{-1}	1.99×10^{-14}	1.37×10^{-14}	4.45×10^{-15}	6.79×10^{-16}	4.82×10^{-17}	1.58×10^{-18}
3.49	1.80×10^{3}	3.60×10^{3}	9.17×10^{-1}	1.86×10^{-10}	1.28×10^{-10}	4.16×10^{-11}	6.36×10^{-12}	4.55×10^{-13}	1.51×10^{-14}
4.08	1.80×10^{3}	3.60×10^{3}	1.10	9.38×10^{-8}	6.45×10^{-8}	2.10×10^{-8}	3.21×10^{-9}	2.30×10^{-10}	7.71×10^{-12}
4.79	1.80×10^{3}	3.60×10^{3}	1.33	6.31×10^{-6}	4.34×10^{-6}	1.41×10^{-6}	2.16×10^{-7}	1.55×10^{-8}	5.23×10^{-10}
5.67	1.80×10^{3}	3.60×10^{3}	1.60	1.07×10^{-4}	7.33×10^{-5}	2.38×10^{-5}	3.65×10^{-6}	2.63×10^{-7}	8.89×10^{-9}
6.75	1.80×10^{3}	3.60×10^{3}	1.91	6.99×10^{-4}	4.81×10^{-4}	1.56×10^{-4}	2.39×10^{-5}	1.73×10^{-6}	5.87×10^{-8}
8.07	1.80×10^{3}	3.60×10^{3}	2.28	2.41×10^{-3}	1.66×10^{-3}	5.37×10^{-4}	8.24×10^{-5}	5.95×10^{-6}	2.03×10^{-7}
9.68	1.80×10^{3}	3.60×10^{3}	2.72	5.35×10^{-3}	3.68×10^{1}	1.19×10^{-3}	1.83×10^{-4}	1.32×10^{-5}	4.51×10^{-7}
1.17×10^{1}	1.80×10^{3}	3.60×10^{3}	3.22	8.87×10^{-3}	6.09×10^{-3}	1.98×10^{-3}	3.03×10^{-4}	2.19×10^{-5}	7.48×10^{-7}
1.41×10^{1}	1.81×10^{3}	3.60×10^{3}	3.79	1.22×10^{-2}	8.38×10^{-3}	2.72×10^{-3}	4.17×10^{-4}	3.02×10^{-5}	1.03×10^{-6}
1.71×10^{1}	1.81×10^{3}	3.60×10^{3}	4.43	1.49×10^{-2}	1.03×10^{-2}	3.33×10^{-3}	5.11×10^{-4}	3.70×10^{-5}	1.27×10^{-6}
2.07×10^{1}	1.81×10^{3}	3.60×10^{3}	5.11	1.69×10^{-2}	1.16×10^{-2}	3.78×10^{-3}	5.80×10^{-4}	4.20×10^{-5}	1.43×10^{-6}
2.52×10^{1}	1.81×10^{3}	3.60×10^{3}	5.79	1.82×10^{-2}	1.25×10^{-2}	4.05×10^{-3}	6.22×10^{-4}	4.50×10^{-5}	1.54×10^{-6}
3.07×10^{1}	1.81×10^{3}	3.60×10^{3}	6.55	1.84×10^{-2}	1.27×10^{-2}	4.11×10^{-3}	6.31×10^{-4}	4.57×10^{-5}	1.57×10^{-6}

(continued)

Table C-4 (cont)

Time Averaged (TAV = 3,600 s) Volume Concentration: Concentration in the z = 1.60 Plane.

Downwind Distance x (m)	Time of Max Conc (s)	Cloud Duration (s)	Effective Half Width bbc (m)	Average Concentration (Volume Fraction) at (x,y,z), y/bbc =					
				0.0	0.5	1.0	1.5	2.0	2.5
3.74×10^{1}	1.82×10^{3}	3.60×10^{3}	7.42	1.80×10^{-2}	1.23×10^{-2}	4.01×10^{-3}	6.15×10^{-4}	4.45×10^{-5}	1.52×10^{-6}
4.56×10^{1}	1.82×10^{3}	3.60×10^{3}	8.39	1.70×10^{-2}	1.17×10^{-2}	3.78×10^{-3}	5.80×10^{-4}	4.20×10^{-5}	1.43×10^{-6}
5.57×10^{1}	1.83×10^{3}	3.60×10^{3}	9.47	1.56×10^{-2}	1.08×10^{-2}	3.49×10^{-3}	5.35×10^{-4}	3.88×10^{-5}	1.33×10^{-6}
6.81×10^{1}	1.83×10^{3}	3.60×10^{3}	1.07×10^{1}	1.42×10^{-2}	9.77×10^{-3}	3.17×10^{-3}	4.86×10^{-4}	3.52×10^{-5}	1.20×10^{-6}
8.32×10^{1}	1.84×10^{3}	3.60×10^{3}	1.20×10^{1}	1.28×10^{-2}	8.77×10^{-3}	2.85×10^{-3}	4.37×10^{-4}	3.16×10^{-5}	1.08×10^{-6}
1.02×10^{2}	1.85×10^{3}	3.60×10^{3}	1.34×10^{1}	1.14×10^{-2}	7.81×10^{-3}	2.53×10^{-3}	3.89×10^{-4}	2.82×10^{-5}	9.63×10^{-7}
1.25×10^{2}	1.86×10^{3}	3.60×10^{3}	1.51×10^{1}	1.00×10^{-2}	6.90×10^{-3}	2.24×10^{-3}	3.43×10^{-4}	2.49×10^{-5}	8.50×10^{-7}
1.52×10^{2}	1.87×10^{3}	3.60×10^{3}	1.70×10^{1}	8.80×10^{-3}	6.05×10^{-3}	1.96×10^{-3}	3.01×10^{-4}	2.18×10^{-5}	7.44×10^{-7}
1.87×10^{2}	1.89×10^{3}	3.60×10^{3}	1.92×10^{1}	7.68×10^{-3}	5.28×10^{-3}	1.71×10^{-3}	2.63×10^{-4}	1.90×10^{-5}	6.51×10^{-7}
2.29×10^{2}	1.90×10^{3}	3.60×10^{3}	2.18×10^{1}	6.65×10^{-3}	4.57×10^{-3}	1.48×10^{-3}	2.27×10^{-4}	1.65×10^{-5}	5.61×10^{-7}
2.80×10^{2}	1.93×10^{3}	3.60×10^{3}	2.49×10^{1}	5.71×10^{-3}	3.92×10^{-3}	1.27×10^{-3}	1.95×10^{-4}	1.41×10^{-5}	4.84×10^{-7}
3.43×10^{2}	1.96×10^{3}	3.60×10^{3}	2.87×10^{1}	4.85×10^{-3}	3.33×10^{-3}	1.08×10^{-3}	1.66×10^{-4}	1.20×10^{-5}	4.10×10^{-7}
4.20×10^{2}	1.99×10^{3}	3.60×10^{3}	3.33×10^{1}	4.07×10^{-3}	2.80×10^{-3}	9.09×10^{-4}	1.39×10^{-4}	1.01×10^{-5}	3.44×10^{-7}
5.15×10^{2}	2.04×10^{3}	3.60×10^{3}	3.91×10^{1}	3.38×10^{-3}	2.32×10^{-3}	7.55×10^{-4}	1.16×10^{-4}	8.38×10^{-6}	2.89×10^{-7}
6.30×10^{2}	2.09×10^{3}	3.60×10^{3}	4.65×10^{1}	2.77×10^{-3}	1.91×10^{-3}	6.19×10^{-4}	9.49×10^{-5}	6.87×10^{-6}	2.36×10^{-7}
7.73×10^{2}	2.15×10^{3}	3.60×10^{3}	5.58×10^{1}	2.25×10^{-3}	1.54×10^{-3}	5.01×10^{-4}	7.68×10^{-5}	5.57×10^{-6}	1.90×10^{-7}
9.47×10^{2}	2.23×10^{3}	3.60×10^{3}	6.75×10^{1}	1.80×10^{-3}	1.24×10^{-3}	4.02×10^{-4}	6.16×10^{-5}	4.46×10^{-6}	1.49×10^{-7}
1.16×10^{3}	2.33×10^{3}	3.60×10^{3}	8.23×10^{1}	1.43×10^{-3}	9.82×10^{-4}	3.19×10^{-4}	4.89×10^{-5}	3.54×10^{-6}	1.22×10^{-7}
1.42×10^{3}	2.45×10^{3}	3.60×10^{3}	1.01×10^{2}	1.12×10^{-3}	7.73×10^{-4}	2.51×10^{-4}	3.85×10^{-5}	2.79×10^{-6}	9.64×10^{-8}
1.74×10^{3}	2.60×10^{3}	3.60×10^{3}	1.24×10^{2}	8.81×10^{-4}	6.05×10^{-4}	1.96×10^{-4}	3.01×10^{-5}	2.18×10^{-6}	7.55×10^{-8}
2.13×10^{3}	2.78×10^{3}	3.60×10^{3}	1.52×10^{2}	6.86×10^{-4}	4.71×10^{-4}	1.53×10^{-4}	2.35×10^{-5}	1.70×10^{-6}	5.91×10^{-8}
2.62×10^{3}	3.00×10^{3}	3.60×10^{3}	1.86×10^{2}	5.31×10^{-4}	3.65×10^{-4}	1.19×10^{-4}	1.82×10^{-5}	1.32×10^{-6}	4.37×10^{-8}
3.21×10^{3}	3.27×10^{3}	3.60×10^{3}	2.28×10^{2}	4.08×10^{-4}	2.81×10^{-4}	9.11×10^{-5}	1.40×10^{-5}	1.01×10^{-6}	3.52×10^{-8}
3.93×10^{3}	3.60×10^{3}	3.60×10^{3}	2.77×10^{2}	3.09×10^{-4}	2.13×10^{-4}	6.90×10^{-5}	1.06×10^{-5}	7.65×10^{-7}	2.70×10^{-8}
4.82×10^{3}	4.10×10^{3}	3.87×10^{3}	3.40×10^{2}	2.05×10^{-4}	1.41×10^{-4}	4.58×10^{-5}	7.02×10^{-6}	5.10×10^{-7}	1.76×10^{-8}
5.94×10^{3}	4.70×10^{3}	4.19×10^{3}	4.14×10^{2}	1.39×10^{-4}	9.57×10^{-5}	3.11×10^{-5}	4.77×10^{-6}	3.46×10^{-7}	1.09×10^{-8}
7.33×10^{3}	5.45×10^{3}	4.58×10^{3}	5.02×10^{2}	9.06×10^{-5}	6.22×10^{-5}	2.02×10^{-5}	3.10×10^{-6}	2.24×10^{-7}	8.61×10^{-9}
9.07×10^{3}	6.36×10^{3}	5.03×10^{3}	6.05×10^{2}	5.27×10^{-5}	3.62×10^{-5}	1.17×10^{-5}	1.80×10^{-6}	1.31×10^{-7}	4.02×10^{-9}
1.13×10^{4}	7.47×10^{3}	5.57×10^{3}	7.23×10^{2}	2.55×10^{-5}	1.75×10^{-5}	5.70×10^{-6}	8.73×10^{-7}	6.35×10^{-8}	2.33×10^{-9}
1.40×10^{4}	8.84×10^{3}	6.11×10^{3}	8.62×10^{2}	1.46×10^{-5}	1.00×10^{-5}	3.26×10^{-6}	5.00×10^{-7}	3.61×10^{-8}	1.59×10^{-9}
1.75×10^{4}	1.05×10^{4}	6.67×10^{3}	1.02×10^{3}	1.04×10^{-5}	7.13×10^{-6}	2.31×10^{-6}	3.55×10^{-7}	2.58×10^{-8}	6.70×10^{-10}
2.20×10^{4}	1.26×10^{4}	7.49×10^{3}	1.21×10^{3}	5.98×10^{-6}	4.11×10^{-6}	1.33×10^{-6}	2.05×10^{-7}	1.48×10^{-8}	4.55×10^{-10}

Table C-5. Input for DEGADIS Simulation of a Vertical Wellhead Release

Value			Line Number
Release from a			1
Well Head:			2
Verticle Jet Simulation			3
			4
1.5	10.		5
0.1			6
1	6	0.	7
273.	1.	75.	8
273.			9
CPD			10
25.2			11
3,600.			12
273.			13
4.7×10^{-4}	1.0×10^{-4}	1.6	14
0	1,500.	0.0	15
0			16
7.69			17
5.0	0.0192		18
3,600.			19
50.			20

Line 18 contains the height of release (5 m) and the effective diameter (0.0192 m)

Line 19 is the duration of release, 3,600 s.

Line 20 is the distance between points at which DEGADIS calculates the output.

DEGADIS Output

A partial DEGADIS output is given in Table C-6. The first column gives the distance downwind and the second gives the elevation. As can be seen, the plume rises substantially because of its initial momentum. The third column gives the concentration of the released gas as a mole fraction, the fourth column gives the concentration in kg/m^3 and the fifth column gives the density in kg/m^3. As can be seen, the density rapidly approaches that of the surrounding air, 1.29 kg/m^3. The fifth column gives the temperature of the plume, which remains constant at 273K because the released plume and the air both have that temperature. The sixth column gives the plume horizontal standard deviation, σ y, and the seventh column gives the vertical standard deviation, σ z (the concentration across the plume is approximated by a Gaussian distribution in DEGADIS). As can be seen, at a height of 1.60 m, the predicted width of the plume (the distance across the wind to the upper or lower Levels of Concern, LC_{01} and ERPG-2) is zero so that LOCs are not predicted to be seen at ground level. This is a typical result for vertical jets of sour gas in stable weather conditions, whether DEGADIS, SLAB, or SAPLUME is used.

SAMPLE SAPLUME CALCULATIONS

SAPLUME Input

Table C-7 contains the input for the model SAPLUME corresponding to Table C-3, which contains the SLAB input for a horizontal release with composition D. The first few lines of input begin with four asterisks and are title cards, followed by a blank which tells the code that the titles have ended. Each subsequent line or group of lines begins with a keyword, followed by numbers in exponential notation to three significant figures.

"SITE" tells SAPLUME that there is a site with one radius and one sector (this is the default when the model is not considering a real site). The following line gives the one radius, arbitrarily set at 10,000 m, with one person arbitrarily set at that point (in the mode of operation chosen for the current problem, the model ignores these numbers).

"WEATHER" specifies that one weather condition only, category F, is being considered (because the 1.000 that follows WEATHER begins at space 61. For E the space would be 51, for D, 41 and so forth. The model can consider all six weather categories at once with up to four velocity subdivisions in each.) In this case, there is one velocity subdivision, specified as 1.5 m/s (first line after weather), and the probability that the wind blows into the one sector is unity (second line after weather).

Table C-6. Partial DEGADIS Output - Vertical Jet

Release from a Wellhead Pipeline Vertical Jet Simulation

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σ y (m)	σ z (m)	At z = 1.60 m			Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
								Mole Fraction	Width to mol%: 1.00×10^{-2} (m)	4.70×10^{-2} (m)		
1.000×10^{-30}	5.15	1.00	1.13	1.13	273	1.060×10^{-2}	1.059×10^{-2}	.000	0	0	1.00	5.15
29.5	120.	8.279×10^{-4}	9.314×10^{-4}	1.29	273	12.1	12.0	.000	0	0	8.279×10^{-4}	120.
61.4	142.	5.644×10^{-4}	6.349×10^{-4}	1.29	273	16.0	15.6	.000	0	0	5.644×10^{-4}	142.
99.6	157.	4.254×10^{-4}	4.786×10^{-4}	1.29	273	19.2	18.4	.000	0	0	4.254×10^{-4}	157.
142.	169.	3.425×10^{-4}	3.853×10^{-4}	1.29	273	22.0	20.6	.000	0	0	3.425×10^{-4}	169.
191.	180.	2.832×10^{-4}	3.186×10^{-4}	1.29	273	24.6	22.4	.000	0	0	2.832×10^{-4}	180.
240.	188.	2.432×10^{-4}	2.736×10^{-4}	1.29	273	27.0	23.9	.000	0	0	2.432×10^{-4}	188.
289.	196.	2.140×10^{-4}	2.408×10^{-4}	1.29	273	29.2	25.2	.000	0	0	2.140×10^{-4}	196.
339.	202.	1.915×10^{-4}	2.155×10^{-4}	1.29	273	31.4	26.3	.000	0	0	1.915×10^{-4}	202.
389.	207.	1.736×10^{-4}	1.953×10^{-4}	1.29	273	33.4	27.2	.000	0	0	1.736×10^{-4}	207.
438.	212.	1.588×10^{-4}	1.786×10^{-4}	1.29	273	35.5	28.1	.000	0	0	1.588×10^{-4}	212.
488.	217.	1.464×10^{-4}	1.647×10^{-4}	1.29	273	37.5	28.8	.000	0	0	1.464×10^{-4}	217.
538.	221.	1.358×10^{-4}	1.528×10^{-4}	1.29	273	39.4	29.5	.000	0	0	1.358×10^{-4}	221.
588.	225.	1.267×10^{-4}	1.425×10^{-4}	1.29	273	41.4	30.1	.000	0	0	1.267×10^{-4}	225.
638.	228.	1.187×10^{-4}	1.335×10^{-4}	1.29	273	43.4	30.7	.000	0	0	1.187×10^{-4}	228.
688.	231.	1.116×10^{-4}	1.255×10^{-4}	1.29	273	45.3	31.2	.000	0	0	1.116×10^{-4}	231.
738.	234.	1.053×10^{-4}	1.185×10^{-4}	1.29	273	47.2	31.7	.000	0	0	1.053×10^{-4}	234.
787.	237.	9.965×10^{-5}	1.121×10^{-4}	1.29	273	49.2	32.2	.000	0	0	9.965×10^{-5}	237.
837.	240.	9.457×10^{-5}	1.064×10^{-4}	1.29	273	51.1	32.6	.000	0	0	9.457×10^{-5}	240.
887.	242.	8.995×10^{-5}	1.012×10^{-4}	1.29	273	53.1	33.0	.000	0	0	8.995×10^{-5}	242.
937.	245.	8.575×10^{-5}	9.647×10^{-5}	1.29	273	55.0	33.4	.000	0	0	8.575×10^{-5}	245.
987.	247.	8.190×10^{-5}	9.213×10^{-5}	1.29	273	56.9	33.8	.000	0	0	8.190×10^{-5}	247.
1.037×10^{3}	249.	7.836×10^{-5}	8.816×10^{-5}	1.29	273	58.9	34.2	.000	0	0	7.836×10^{-5}	249.
1.087×10^{3}	251.	7.510×10^{-5}	8.449×10^{-5}	1.29	273	60.8	34.5	.000	0	0	7.510×10^{-5}	251.
1.137×10^{3}	253.	7.208×10^{-5}	8.109×10^{-5}	1.29	273	62.7	34.9	.000	0	0	7.208×10^{-5}	253.
1.187×10^{3}	255.	6.928×10^{-5}	7.794×10^{-5}	1.29	273	64.7	35.2	.000	0	0	6.928×10^{-5}	255.
1.237×10^{3}	257.	6.667×10^{-5}	7.501×10^{-5}	1.29	273	66.6	35.5	.000	0	0	6.667×10^{-5}	257.
1.287×10^{3}	258.	6.424×10^{-5}	7.228×10^{-5}	1.29	273	68.5	35.8	.000	0	0	6.424×10^{-5}	258.
1.337×10^{3}	260.	6.197×10^{-5}	6.972×10^{-5}	1.29	273	70.5	36.1	.000	0	0	6.197×10^{-5}	260.
1.387×10^{3}	262.	5.984×10^{-5}	6.733×10^{-5}	1.29	273	72.4	36.3	.000	0	0	5.984×10^{-5}	262.

Table C-6 (cont)

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σ y (m)	σ z (m)	At z = 1.60 m Mole Fraction	Width to mol%: 1.00 x 10^{-2} (m)	4.70 x 10^{-2} (m)	Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
1.437 x 10^3	263.	5.785 x 10^{-5}	6.508 x 10^{-5}	1.29	273	74.3	36.6	.000	0	0	5.785 x 10^{-5}	263.
1.487 x 10^3	265.	5.597 x 10^{-5}	6.296 x 10^{-5}	1.29	273	76.3	36.9	.000	0	0	5.597 x 10^{-5}	265.
1.537 x 10^3	266.	5.420 x 10^{-5}	6.097 x 10^{-5}	1.29	273	78.2	37.1	.000	0	0	5.420 x 10^{-5}	266.
1.587 x 10^3	267.	5.253 x 10^{-5}	5.909 x 10^{-5}	1.29	273	80.2	37.4	.000	0	0	5.253 x 10^{-5}	267.
1.637 x 10^3	269.	5.095 x 10^{-5}	5.732 x 10^{-5}	1.29	273	82.1	37.6	.000	0	0	5.095 x 10^{-5}	269.
1.687 x 10^3	270.	4.945 x 10^{-5}	5.564 x 10^{-5}	1.29	273	84.0	37.9	.000	0	0	4.945 x 10^{-5}	270.
1.737 x 10^3	271.	4.804 x 10^{-5}	5.404 x 10^{-5}	1.29	273	85.9	38.1	.000	0	0	4.804 x 10^{-5}	271.
1.787 x 10^3	273.	4.669 x 10^{-5}	5.253 x 10^{-5}	1.29	273	87.9	38.3	.000	0	0	4.669 x 10^{-5}	273.
1.837 x 10^3	274.	4.542 x 10^{-5}	5.109 x 10^{-5}	1.29	273	89.8	38.6	.000	0	0	4.542 x 10^{-5}	274.
1.887 x 10^3	275.	4.420 x 10^{-5}	4.973 x 10^{-5}	1.29	273	91.7	38.8	.000	0	0	4.420 x 10^{-5}	275.
1.937 x 10^3	276.	4.304 x 10^{-5}	4.842 x 10^{-5}	1.29	273	93.7	39.0	.000	0	0	4.304 x 10^{-5}	276.
1.987 x 10^3	277.	4.194 x 10^{-5}	4.718 x 10^{-5}	1.29	273	95.6	39.2	.000	0	0	4.194 x 10^{-5}	277.
2.037 x 10^3	278.	4.089 x 10^{-5}	4.600 x 10^{-5}	1.29	273	97.5	39.5	.000	0	0	4.089 x 10^{-5}	278.
2.087 x 10^3	279.	3.988 x 10^{-5}	4.487 x 10^{-5}	1.29	273	99.4	39.7	.000	0	0	3.988 x 10^{-5}	279.
2.137 x 10^3	280.	3.892 x 10^{-5}	4.378 x 10^{-5}	1.29	273	101.	39.9	.000	0	0	3.892 x 10^{-5}	280.
2.187 x 10^3	281.	3.800 x 10^{-5}	4.275 x 10^{-5}	1.29	273	103.	40.1	.000	0	0	3.800 x 10^{-5}	281.
2.237 x 10^3	282.	3.711 x 10^{-5}	4.175 x 10^{-5}	1.29	273	105.	40.3	.000	0	0	3.711 x 10^{-5}	282.
2.287 x 10^3	283.	3.627 x 10^{-5}	4.080 x 10^{-5}	1.29	273	107.	40.5	.000	0	0	3.627 x 10^{-5}	283.
2.337 x 10^3	284.	3.546 x 10^{-5}	3.989 x 10^{-5}	1.29	273	109.	40.7	.000	0	0	3.546 x 10^{-5}	284.
2.387 x 10^3	285.	3.468 x 10^{-5}	3.901 x 10^{-5}	1.29	273	111.	40.9	.000	0	0	3.468 x 10^{-5}	285.
2.437 x 10^3	286.	3.393 x 10^{-5}	3.817 x 10^{-5}	1.29	273	113.	41.1	.000	0	0	3.393 x 10^{-5}	286.
2.487 x 10^3	286.	3.321 x 10^{-5}	3.736 x 10^{-5}	1.29	273	115.	41.2	.000	0	0	3.321 x 10^{-5}	286.
2.537 x 10^3	287.	3.252 x 10^{-5}	3.658 x 10^{-5}	1.29	273	117.	41.4	.000	0	0	3.252 x 10^{-5}	287.
2.587 x 10^3	288.	3.185 x 10^{-5}	3.583 x 10^{-5}	1.29	273	119.	41.6	.000	0	0	3.185 x 10^{-5}	288.
2.637 x 10^3	289.	3.121 x 10^{-5}	3.511 x 10^{-5}	1.29	273	120.	41.8	.000	0	0	3.121 x 10^{-5}	289.
2.687 x 10^3	290.	3.059 x 10^{-5}	3.441 x 10^{-5}	1.29	273	122.	42.0	.000	0	0	3.059 x 10^{-5}	290.
2.737 x 10^3	290.	2.999 x 10^{-5}	3.374 x 10^{-5}	1.29	273	124.	42.2	.000	0	0	2.999 x 10^{-5}	290.
2.787 x 10^3	291.	2.941 x 10^{-5}	3.309 x 10^{-5}	1.29	273	126.	42.3	.000	0	0	2.941 x 10^{-5}	291.
2.837 x 10^3	292.	2.885 x 10^{-5}	3.246 x 10^{-5}	1.29	273	128.	42.5	.000	0	0	2.885 x 10^{-5}	292.
2.887 x 10^3	293.	2.831 x 10^{-5}	3.185 x 10^{-5}	1.29	273	130.	42.7	.000	0	0	2.831 x 10^{-5}	293.
2.937 x 10^3	293.	2.779 x 10^{-5}	3.127 x 10^{-5}	1.29	273	132.	42.9	.000	0	0	2.779 x 10^{-5}	293.
2.987 x 10^3	294.	2.729 x 10^{-5}	3.070 x 10^{-5}	1.29	273	134.	43.0	.000	0	0	2.729 x 10^{-5}	294.
3.037 x 10^3	295.	2.680 x 10^{-5}	3.015 x 10^{-5}	1.29	273	136.	43.2	.000	0	0	2.680 x 10^{-5}	295.

Table C-6 (cont)

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σy (m)	σz (m)	At z = 1.60 m			Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
								Mole Fraction	Width to mol%: 1.00×10^{-2} (m)	Width to mol%: 4.70×10^{-2} (m)		
3.087×10^3	295.	2.633×10^{-5}	2.962×10^{-5}	1.29	273	138.	43.4	.000	0	0	2.633×10^{-5}	295.
3.137×10^3	296.	2.588×10^{-5}	2.911×10^{-5}	1.29	273	139.	43.5	.000	0	0	2.588×10^{-5}	296.
3.187×10^3	297.	2.543×10^{-5}	2.861×10^{-5}	1.29	273	141.	43.7	.000	0	0	2.543×10^{-5}	297.
3.237×10^3	297.	2.500×10^{-5}	2.813×10^{-5}	1.29	273	143.	43.9	.000	0	0	2.500×10^{-5}	297.
3.262×10^3	297.	2.479×10^{-5}	2.789×10^{-5}	1.29	273	144.	43.9	.000	0	0	2.479×10^{-5}	297.

The entries on the "PROPERTIES" line are as follows: the ambient temperature is 273K at which temperature the density of air is 1.29 kg/m^3 and its specific heat at constant pressure is 990 J/kg/K. At a temperature of 273K, the density of the released gas is 1.141 kg/m^3 and the specific heat at constant pressure is 1,500 J/kg/K.

The entries on the "SOURCE" line are as follows: the rate of release is 7.69 kg/m^3 at a temperature of 273K. The amount of air initially entrained with the source is zero. The angle of release is zero radians (horizontal). The height of release is 5 m. The initial momentum flux is 2,540 kg m s^{-2} and is the product of the rate of release and the exit velocity (the speed of sound is approximately 330 m/s).

The "INTERVAL" line specifies that SAPLUME calculations start at a downwind distance x of 0.1 m and that calculations are performed at a uniform spacing of 0.15 in $\log_{10}(x)$.

On the "ROUG" line, the surface roughness length is 0.1 m and the windspeed is measured at a height of 10 m.

The "HAZARD" line specifies two levels of concern. As explained above in the discussion of the SLAB results, these are the LC_{01} of 470 ppm (approximately 5.32×10^{-4} kg/m^3) and the ERPG-2 of 100 ppm (1.141×10^{-4} kg/m^3).

"VGRAD" informs SAPLUME that it should consider the velocity gradient and the temperature gradient in the atmosphere. SAPLUME uses standard textbook formulae for these gradients. If the first entry after VGRAD were zero, velocity would be constant as a function of height. Similarly, if the second entry after VGRAD were zero, the temperature of the atmosphere would remain constant as height increases.

A value of 3 after "NEUT" specifies one of three parametrizations for the standard deviations in the Gaussian model once the released material has evolved out of the jet phase. NEUT =3 corresponds to a parameterization that is appropriate for a rural site. "DUR" specifies that the duration of release is one hour.

Finally, the repetition of "END" terminates the run of SAPLUME.

SAPLUME Output

A partial SAPLUME output corresponding to the input in Table C-7 is given in Table C-8. This table indicates that, for hazard level 1 (i.e., the LC_{01} of 470 ppm discussed above) the plume touches down at a downwind distance of approximately 63 m and extends to about 3 km, covering an area of about 10^5 m^2 (one tenth of a square kilometer). The table of pairs of values of downwind distance, x, and width can be coupled to a plotting routine to give contours of constant concentration. Similarly, hazard level 2 (the ERPG-2 of 100 ppm)

Table C-7. Input for SAPLUME Runs

****	EPA Hydrogen Sulfide Runs					
****	January 1993					
****	No Protective Measures					
****	Composition D - 30% H_2S at Wellhead					
****	$2x10^7$ SCFD:					
****	Horizontal Release					
****	H_2S Release Rate - 3.073 kg/s					
****	Total Mixture Release Rate - 7.69 kg/s					
****	Hazard Level - ERPG-2 (100 ppm) and					
****	LC_{01} (470 ppm) Both Adjusted for Stream Composition					
****	Category F Weather, Windspeed 1.5 m/s					
SITE	1.000	1.000				
$1.000x10^4$						
1.000						
WEATHER	1.000					
1.500						
$2.500x10^{-1}$						
PROP	$2.730x10^2$	1.290	$9.900x10^2$	$2.730x10^2$	1.141	$1.500x10^3$
SOURCE	7.690	$2.730x10^2$	0.000	0.000	5.000	$2.540x10^3$
INTERVAL	$1.000x10^{-1}$	$1.5000x10^{-1}$				
ROUG	$1.0000x10^{-1}$	$1.000x10^1$				
HAZARD	2.000					
$5.320x10^{-4}$	$1.141x10^{-4}$					
VGRAD	1.000	1.000				
NEUT	3.000					
DUR	1.000					
END						
END						

Table C-8. Partial SAPLUME Output for Horizontal Plume

FOR HAZARD LEVEL 1, WINDSPEED 1.500 m/s AND CATEGORY 6

THE HAZARDOUS CLOUD EXTENDS FROM $6.327x10^{1}$ TO $3.126x10^{3}$ METERS DOWNWIND AND HAS AN AREA OF $1.129x10^{5}$ m^2

CLOUD BOUNDARIES

X[a] (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)
0.000	0.000	$1.000x10^{-1}$	0.000	$1.162x10^{-1}$	0.000	$1.350x10^{-1}$	0.000	$1.568x10^{-1}$	0.000
$1.822x10^{-1}$	0.000	$2.117x10^{-1}$	0.000	$2.460x10^{-1}$	0.000	$2.858x10^{-1}$	0.000	$3.320x10^{-1}$	0.000
$3.857x10^{-1}$	0.000	$4.482x10^{-1}$	0.000	$5.207x10^{-1}$	0.000	$6.050x10^{-1}$	0.000	$7.029x10^{-1}$	0.000
$8.166x10^{-1}$	0.000	$9.488x10^{-1}$	0.000	1.102	0.000	1.281	0.000	1.488	0.000
1.729	0.000	2.009	0.000	2.334	0.000	2.711	0.000	3.150	0.000
3.660	0.000	4.252	0.000	4.940	0.000	5.740	0.000	6.669	0.000
7.748	0.000	9.002	0.000	$1.046x10^{1}$	0.000	$1.215x10^{1}$	0.000	$1.412x10^{1}$	0.000
$1.640x10^{1}$	0.000	$1.906x10^{1}$	0.000	$2.214x10^{1}$	0.000	$2.572x10^{1}$	0.000	$2.989x10^{1}$	0.000
$3.472x10^{1}$	0.000	$4.034x10^{1}$	0.000	$4.687x10^{1}$	0.000	$5.446x10^{1}$	0.000	$6.327x10^{1}$	5.555
$7.351x10^{1}$	2.627	$8.540x10^{1}$	2.739	$9.922x10^{1}$	2.955	$1.153x10^{2}$	3.294	$1.339x10^{2}$	3.768
$1.556x10^{2}$	4.385	$1.808x10^{2}$	5.149	$2.101x10^{2}$	6.066	$2.441x10^{2}$	7.143	$2.835x10^{2}$	8.388
$3.294x10^{2}$	9.811	$3.827x10^{2}$	$1.142x10^{1}$	$4.447x10^{2}$	$1.324x10^{1}$	$5.167x10^{2}$	$1.527x10^{1}$	$6.003x10^{2}$	$1.701x10^{1}$
$6.974x10^{2}$	$1.856x10^{1}$	$8.103x10^{2}$	$2.005x10^{1}$	$9.414x10^{2}$	$2.140x10^{1}$	$1.094x10^{3}$	$2.257x10^{1}$	$1.271x10^{3}$	$2.345x10^{1}$
$1.476x10^{3}$	$2.393x10^{1}$	$1.715x10^{3}$	$2.384x10^{1}$	$1.993x10^{3}$	$2.295x10^{1}$	$2.315x10^{3}$	$2.082x10^{1}$	$2.690x10^{3}$	$1.653x10^{1}$
$3.126x10^{3}$	5.139								

[a] x = Downwind distance.

extends from about 60 m to about 12 km downwind, covering an area of approximately 10^6 m^2.

The above results are close to those predicted by SLAB. The higher result is about 50% larger than that predicted by SLAB. However, the difference is within the range of uncertainties expected for these dispersion models. As noted above, the neglect of dry deposition means that the predictions are likely to be conservative.

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16. ABSTRACT

Under section 112(n)(5) of the Clean Air Act Amendments of 1990, the EPA is required to submit this report which assesses the hazards to public health and the environment resulting from the emission of hydrogen sulfide associated with the extraction of oil and natual gas. This assessment is designed to build upon work done under section 8002(m) of the Solid Waste Disposal Act and to reflect consultation with the States. The report includes a review of existing State and industry control standards, techniques, and enforcement and includes recommendations for control of hydrogen sulfide emissions from these sources.

The Office of Air Quality Planning and Standards and the Office of Solid Waste and Emergency Response completed this report on a joint effort. This report provides the information currently available on each of the elements listed above.

17. KEY WORDS AND DOCUMENT ANALYSIS

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