

# RESULTS OF GRI FIELD TESTING OF H<sub>2</sub>S SCAVENGING PROCESSES

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## **INTRODUCTION**

Hydrogen sulfide is a corrosive, poisonous gas with a characteristic rotten egg odor. If present in natural gas, H<sub>2</sub>S must be removed down to 1/4 grain of H<sub>2</sub>S per 100 standard cubic feet (equivalent to 4 ppmv) before the gas can be shipped in the United States interstate pipeline network. Approximately 14% of United States natural gas reserves contain sulfur in the form of H<sub>2</sub>S and at least 15% of natural gas processed annually in the United States requires treatment to remove H<sub>2</sub>S. Roughly two trillion cubic feet of gas produced in 1991 was sour, and more sour gas may be produced as demand for gas increases.<sup>1</sup>

Because of this large amount of sour gas, technology that reduces the cost of sulfur removal and recovery is of great importance to the natural gas industry. To address this need, Gas Research Institute (GRI) has instituted a research program in sulfur removal and recovery from natural gas. Over the past 10 years, the GRI program has focused on liquid redox technology, and in the past two years has expanded into the area of H<sub>2</sub>S scavenging.<sup>2,3</sup>

The primary objective of the evaluation program is to obtain accurate and reliable performance, cost, and environmental data on various classes of H<sub>2</sub>S scavengers. The overall field evaluation program includes liquid-based scavengers in both tower and direct-injection applications and solid-based scavengers.<sup>4</sup> The information will then be used to develop guidelines for selection and optimum use of these processes by the gas industry. The program will also identify data gaps and research and process development needs in this increasingly important area of gas processing.

This paper presents the results of GRI's field evaluation of liquid-based H<sub>2</sub>S scavengers in tower applications at a natural gas production plant in South Texas. Preliminary results for the ongoing evaluation of a solid-based scavenger are also given, along with an update on the field evaluation of direct-injection liquid scavengers. GRI's technology transfer plan also calls for the results of this work to be presented at the Gas Processors Association Annual Convention in March

1995 and GRI's Seventh Sulfur Recovery Conference planned for September 1995. This information will also be published in appropriate industry trade journals and incorporated into software developed by GRI (SeleXpert : Scavenger Module) to aid in the evaluation of scavenger processes for a particular application.

## **OVERVIEW OF SCAVENGING PROCESS TECHNOLOGY**

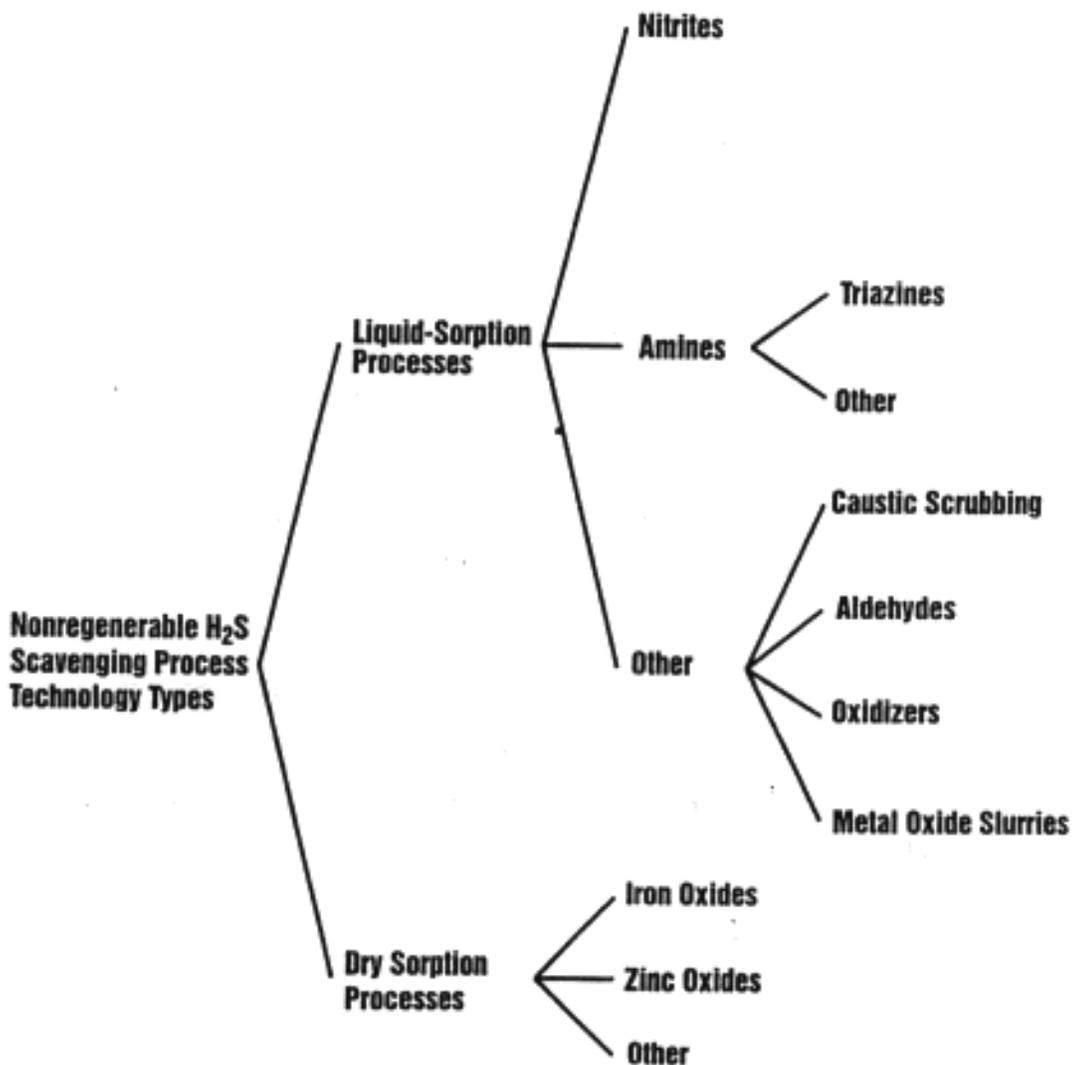
A growing segment of the gas producing industry employs H<sub>2</sub>S scavenging processes to remove low concentrations of H<sub>2</sub>S (usually less than 100 ppm) from subquality natural gas at remote locations. For this gas segment, conventional amine sweetening is not economically feasible, especially when CO<sub>2</sub> removal is not required. Historically, the gas production industry has used nonregenerable H<sub>2</sub>S scavenging processes to treat this gas.

Recent surveys of scavenging technologies indicate a rapidly changing marketplace with numerous new scavenging agents being offered commercially or under development.<sup>5, 6, 7, 8</sup> In some cases, the same chemical agents may be sold under different brand names or with slightly different additive formations. Controversies over ownership of proprietary formulations or process technologies are common, and much of the information required to make process comparisons is not available.

For these reasons, a goal of this research program has been to identify the major classifications of scavenging agents and to collect data from representative scavenging agents from each major classification. Figure 1 shows the organization of nonregenerable scavenging technologies into liquid-based and solid-based processes.

Liquid-based scavengers are typically used in bubble tower contactors or are injected directly into the pipeline. For tower applications, the sour gas stream usually first passes through an inlet filter separator or surge tank to remove entrained liquid droplets from the feed gas stream. The sour gas then enters at the bottom of the tower and bubbles up through the scavenger. The rising bubbles keep the liquid or slurry mixed.

Most solid-phase processes use a metal oxide (e.g., iron oxide) as the scavenging agent supported on an inert substrate. The sour gas feed usually passes through an inlet separator to remove any entrained liquid prior to entering a tower where it contacts the scavenging agent in a batch operation. Continuous treating can be maintained by operating multiple towers in a lead/lag or parallel configuration.



**Figure 1. Major Scavenging Technology Classifications**

# FIELD EVALUATION OF LIQUID-BASED SCAVENGERS IN TOWER APPLICATIONS

## Description of Host Site Facility

In the gas fields near the host site for this program, the host company produces about 80 MMSCFD of non-associated gas with H<sub>2</sub>S levels of 10 and 20 ppmv and CO<sub>2</sub> levels of about 0.5 percent. Approximately 15 to 20 MMSCFD of this gas is treated at the facility where these field tests were conducted. The company has primarily used liquid-phase scavengers to treat this gas, including sodium nitrite-based, nonregenerable amine-based, and triazine-based agents.

Figure 2 shows the natural gas flow from the cooler, through the vertical separator, coalescing separator, and into the scavenging towers. There are two parallel treating towers at the site, and a bypass line around the towers. Figure 3 shows some mechanical design features of the tower vessels. The towers were constructed of carbon steel, rated for 1440 psig at 100 °F. The inside diameter of the towers is 66 inches and the vertical height is 20 feet seam to seam. Each tower is equipped with an inlet gas sparger located near the bottom of the vessel and a mist extractor at the top of the vessel. From the towers, the gas flows through a horizontal separator and is sent to the glycol dehydration unit for further processing.

## Field Test Conditions

The three liquid scavenger types that were evaluated were a nitrite-based scavenger (SULFA-CHECK 2420), a triazine-based scavenger (SULFA-SCRUB HSW 700L), and a nonregenerable amine (GAS TREAT 114). Table 1 presents the field test conditions for each of the test runs. The experimental test matrix called for two test runs for each scavenger type, with each being evaluated in both towers. Production requirements at the host site facility, however, dictated that the second test run of the nonregenerable amine scavenger be conducted in the same tower (tower one) as the first test. The other scavengers were tested once in each tower. Between runs, the towers were cleaned from the bottom manway using a high-pressure water sprayer to avoid contamination of the fresh scavenger material charged for the next test.

SULFA-CHECK is a registered trademark of Nalco/Exxon Energy Chemicals, L.P.

SULFA-SCRUB is a registered trademark of Petrolite Corporation

GAS TREAT is a registered trademark of Champion Technologies, Inc.

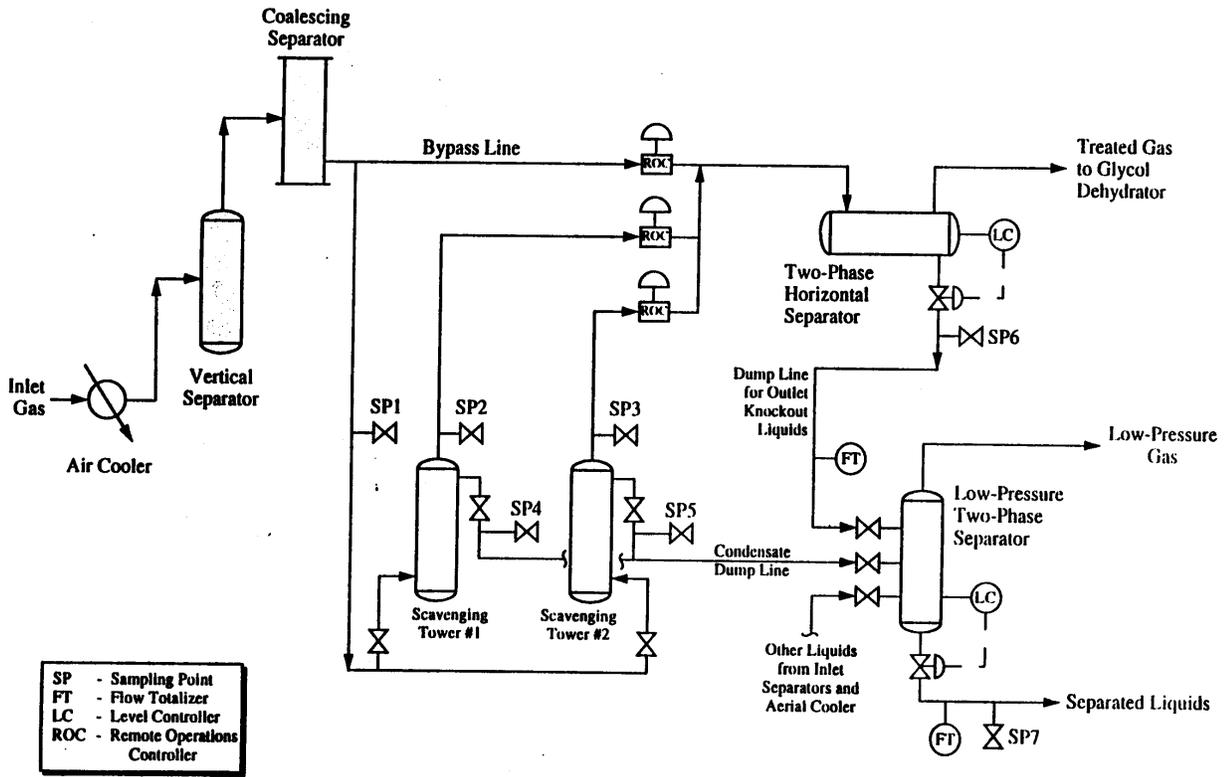
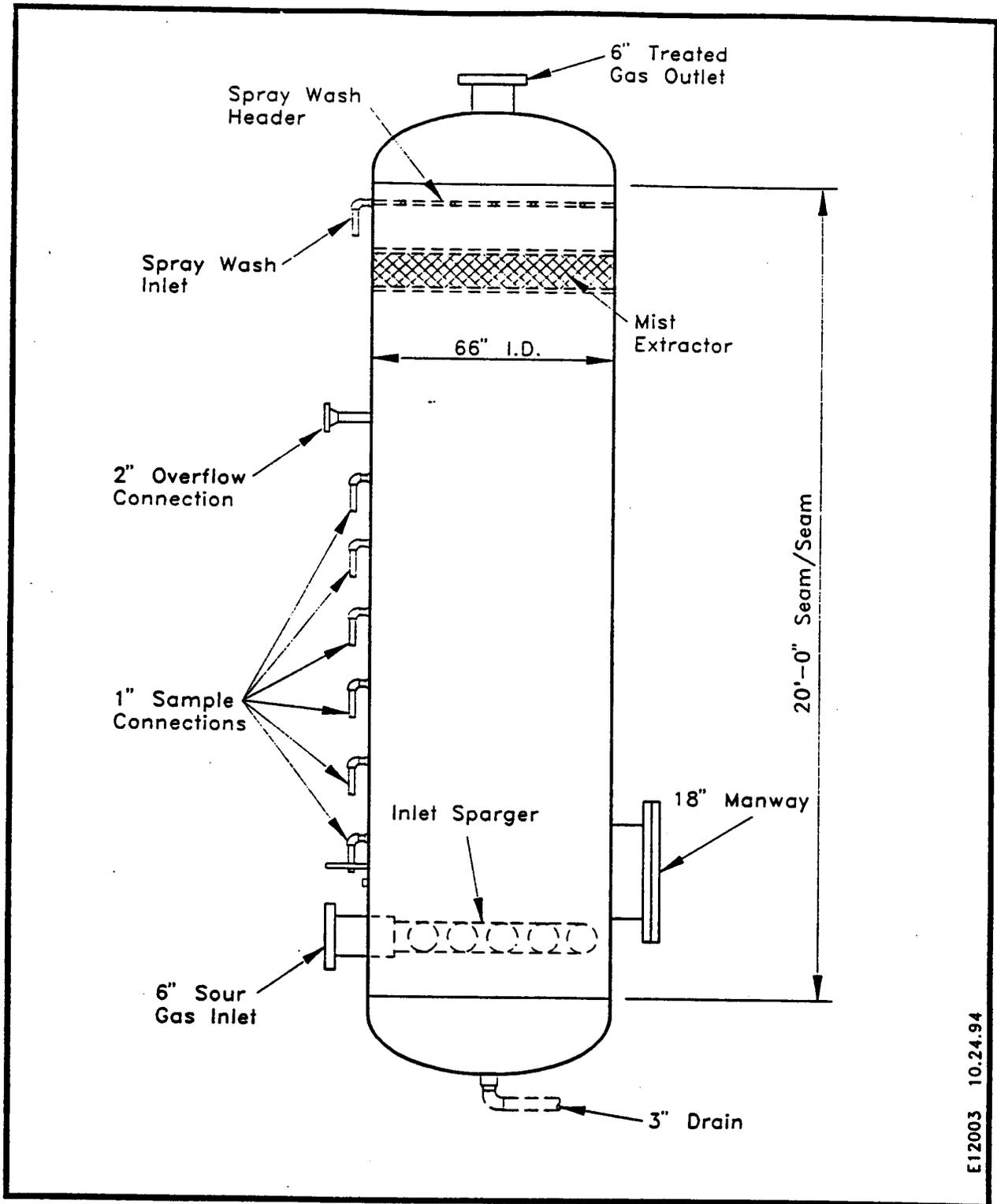


Figure 2. Process Flow Diagram for the Host Site Facility



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Figure 3. Scavenging Tower Design Features

**Table 1**  
**Field Test Conditions**

			Nonregenerable			
	Test 1	Test 2	Test 1	Test 2	Test 1	Test 2
Tower Number	1	2	1	1	2	1
Start Date	3/18/94	4/22/94	4/22/94	6/27/94	3/18/94	5/26/94
Date at which outlet H <sub>2</sub> S exceeded 4 ppm	4/17/94	7/18/94	5/18/94	7/21/94	4/20/94	6/20/94
Tower Changeout Date	4/22/94	7/28/94	5/26/94	7/28/94	4/22/94	6/27/94
Duration of Test, days	35	97	34	31	35	32
Initial Volume of Scavenger Charged into	1100	1100	550	550	550	550
Initial Volume of Water Charged into Tower,	0	0	550	550	550	550
Flow Rate, MMSCFD	8.11	7.13	7.65	6.10	7.97	7.36
Inlet H <sub>2</sub> S Concentration, ppmv	19	19	19	19	19	19
Pressure, psig	957	991	948	1015	965	999
Temperature, °F	86.9	96.0	93.6	102.0	83.7	101.6
Superficial Gas Velocity <sup>a</sup> , ft/sec	0.054	0.047	0.053	0.040	0.052	0.059
Gas Compressibility Factor, Z <sup>b</sup>	0.860	0.865	0.867	0.868	0.856	0.869

<sup>a</sup> Based on actual volumetric flow rate and tower cross-sectional area.

<sup>b</sup> Estimated using the Peng-Robinson equation of state and measured gas composition, temperature, and pressure data.

### Inlet Gas Composition

Table 2 gives a typical average composition of the inlet natural gas based on measurements taken during the test program. It is important to note that this gas is produced at temperatures of greater than 140 °F, and inlet gas precoolers are required to bring the temperature down to near ambient temperatures. This cooling causes water and hydrocarbon liquids to condense from the gas prior to treatment, and as a result the gas was saturated with both hydrocarbons and water.

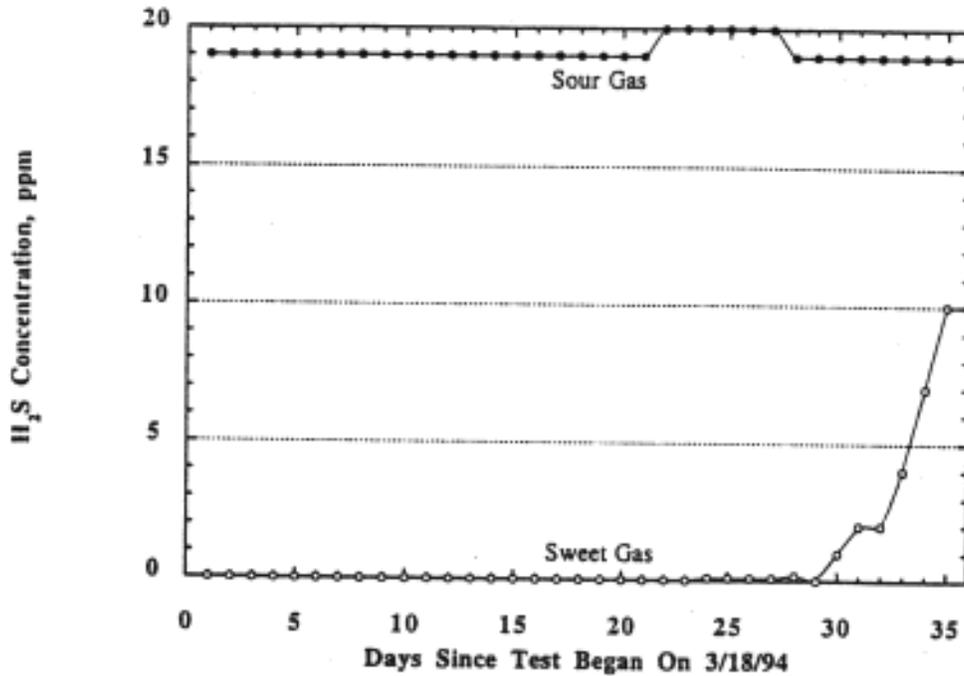
**Table 2****Typical Properties of the Sour Gas at the Host Site**

Temperature, °F	85 - 100
Pressure, psig	950 - 1000
Gas Composition (dry basis)	Mole %
Hydrogen sulfide	0.0019
Nitrogen	0.30
Carbon dioxide	0.54
Methane	95.3
Ethane	1.84
Propane	0.72
Butanes	0.61
Pentanes	0.31
Hexanes	0.23
Benzene	0.070
Toluene	0.026
Xylenes	0.010

**H<sub>2</sub>S Removal Performance**

Each of the three scavenging liquids tested was able to reduce the H<sub>2</sub>S concentration from approximately 19 ppmv to less than 0.1 ppmv under the field test conditions. During most of the testing, H<sub>2</sub>S was not detected in the treated gas. Breakthrough of H<sub>2</sub>S generally occurred at the end of each test as the scavenging agent became exhausted. Figure 4 is typical of the breakthrough curves observed during the testing.<sup>4</sup>

During one test, breakthrough of H<sub>2</sub>S was also observed when foaming resulted in approximately 50 % of the liquid being carried out of the treating vessel into a downstream knockout. During this upset, the outlet H<sub>2</sub>S concentration reached 4 ppmv. This event demonstrated that a minimum contact time is necessary for the complete removal of the H<sub>2</sub>S. Loss of the liquid in the vessel reduced the contact time since the bubbles traveled a shorter distance through the scavenging liquid. After the operator added 450 gallons of water, the outlet H<sub>2</sub>S concentration declined to 1.5 ppmv.



**Figure 4. Triazine Scavenger Breakthrough Curve, First Test Run**

### Scavenging Capacity

The capacity of a nonregenerable scavenger is typically expressed in terms of the pounds of sulfur removed per gallon of scavenging agent or alternately as the gallons of scavenging agent required per ppm H<sub>2</sub>S per MMSCF of gas. The volume of gas treated per gallon of scavenging agent therefore varies inversely with the concentration of H<sub>2</sub>S. The capacity is an important performance characteristic because replacement of the spent scavenging agent can in many cases be the largest single treatment cost component, especially at higher H<sub>2</sub>S concentrations.

The capacities of the scavenging agents varied considerably from run to run at the site. Table 3 shows a comparison of the capacities of the scavenging agents as determined from several sources: 1) the field tests at the host facility, 2) previous laboratory testing by Radian Corporation, and 3) historical data obtained from the host site facility prior to the field testing and under less controlled conditions.<sup>4</sup> The capacities reported in Table 3 correspond to the amount of sulfur removed at the time that the outlet H<sub>2</sub>S concentration first exceeded 4 ppm.

**Table 3**

**Comparison of H<sub>2</sub>S Scavenger Capacity Data**

	Field Test Results		Radian	Host	Representative Values
	Tower 1	Tower 2	Lab Test	Database	
Nitrite					
lb sulfur/gal	0.33	0.88	5.0*	0.29-0.75	0.75
gal/ppmv H <sub>2</sub> S/MMSCF	0.26	0.096	0.017	0.29-0.11	0.11
Nonregenerable Amine					
lb sulfur/gal	0.55, 0.41	NA	0.86	0.39-0.89	0.60
gal/ppmv H <sub>2</sub> S/MMSCF	0.15, 0.21	NA	0.098	0.22-0.095	0.14
Triazine					
lb sulfur/gal	0.51	0.74	0.81	0.47-0.85	0.60
gal/ppmv H <sub>2</sub> S/MMSCF	0.17	0.11	0.10	0.18-0.099	0.14

\* High capacity resulted from absence of CO<sub>2</sub>.

**Potential for Foaming/Plugging:**

During the field testing of the liquid scavengers, all three agents exhibited some foaming and required the addition of antifoam agents. Table 4 presents a summary of the foaming/plugging observations. The most severe foaming occurred with the nitrite scavenger, resulting in carryover of the scavenging solution. Foaming was also encountered with the nonregenerable amine and triazine agents, but to a lesser extent.

Table 4 shows the estimated amounts of liquids that were carried out of the tower as a result of foaming. These volumes were measured by the liquid flow totalizer on the outlet knockout scrubber drain line (see Figure 2). The severe foaming which occurred during the initial testing of the nitrite scavenger resulted in 540 gallons of carryover during a 24-hour period before the operator was aware of the problem. The foaming observed with the nonregenerable amine resulted in smaller amounts of liquid (0 to 150 gallons) carried over each day, with a total

of 400 gallons carried over during the first test. During the second test run, the foaming was controlled better for the nitrite and nonregenerable amine agents, with carryover limited to less than 50 gallons. Foaming was less severe with the triazine agent, and carryover volumes were limited to 50 gallons during the first test and 5 gallons during the second test.

**Table 4**  
**Foaming/Plugging Observations**

	Nitrite	Nonregenerable Amine	Triazine
Foaming Encountered	Yes	Yes	Yes
Carryover Volumes, gallons			
Test No. 1	540	400	<50
Test No. 2	<50	<50	<50
Alcohol-based Antifoams	Yes	Yes	Not Recommended
Silicone-based Antifoams	Not Recommended	Not as Effective	Yes
Operator Attention Required	Yes	Yes	Yes
Plugging Problems Encountered*	None	None	None

\* During the field evaluation

Plugging of equipment is a potential problem for any scavenging agent which produces solid reaction products. The host site has historically encountered plugging in several places:

- Process sampling lines;
- Mist eliminators;
- Gas metering orifice plates;
- Outlet gas knockout vessels;
- Glycol filters in downstream dehydrators;
- Tower drain piping (during tower cleanout); and
- Plugging of associated waste storage tanks and piping.

During the field testing, the plugging problems were limited to plugged sampling valves and some plugging of the tower drain which occurred during changeout of the spent nitrite scavenger. The tower drain was easily unplugged by momentarily reversing the flow through the tower drain during the tower cleanout procedure. The potential for plugging is greatest for the nitrite and nonregenerable amine scavengers, since these agents produced some solid reaction products. Table 5 shows that the nitrite scavenger produced approximately 400 lbs (dry basis) of solid reaction products, and the nonregenerable amine produced 150 - 200 lbs of solids during the test runs. The triazine produced little or no solid reaction products. It is important to note that most of the solids produced by the nonregenerable amine were removed as suspended solids in the spent scavenging solution when the tower was drained.

Plugging problems are aggravated by foaming, since foaming causes the solid reaction products to be transported into downstream piping and equipment. All of the plugging of downstream equipment at the host site is thought to be caused by liquids and solids which were carried out of the tower during uncontrolled foaming episodes. The solid particles, which varied in size from approximately 1 to 200 microns, are also a concern for underground injection well disposal since they have the potential to plug the well.

In addition to the formation of solid reaction products, solids may also be formed through scale buildup. If hard water is used to dilute the scavenging agents in the field, the alkalinity of the treating agents may cause precipitation of salts from the water. The host site personnel have reported observing scale formation after the relatively alkaline spent scavenging agents were blended with hard water in waste storage tanks. The precipitation of carbonate salts may be increased in applications treating natural gas with high levels of carbon dioxide. During the testing, scale inhibitors were added in accordance with the vendor recommendations. These additives controlled the scaling effectively as evidenced by the lack of significant scale buildup on the vessel walls and corrosion coupons during the test.

**Table 5****Formation of Solids During Liquid-Scavenger Tests**

	<b>Nitrite</b>	<b>Nonregenerable Amine</b>	<b>Triazine</b>
Volume of solid material remaining in the tower after draining, gallons	185	0 - 20	0
Specific gravity of solids remaining in the tower	1.38	1.12	NA
Dry mass of solids remaining in the tower after draining, lbs	390	0 - 50	0
Dry mass of solids suspended in the spent scavenger solution, lbs	10	100 - 200	5 - 10
Total dry mass of solids formed, lbs	400	150 - 200	5 - 10

**Maximum Superficial Gas Velocity**

The superficial gas velocity is an important performance parameter since it determines the diameter of the contactor vessel for a given flow. The superficial gas velocity is defined as the actual volumetric flow rate of the gas divided by the cross sectional area of the tower. The superficial velocity is usually expressed in units of feet/second or feet/minute. The contactors at the host site were originally designed for 15 MMSCFD with a superficial velocity of 0.11 ft/sec. However, through trial and error the host site personnel found that foaming and carryover could be minimized by maintaining lower superficial velocities.

The target superficial velocity for the field testing was 0.064 ft/sec, based on a flow rate of 9.0 MMSCFD. However, during the testing, the maximum superficial velocities that could be sustained without foaming and carryover were in the 0.040 to 0.055 ft/sec range. The limiting factor was foaming and carryover, not the ability of the scavenging agents to remove H<sub>2</sub>S under higher velocity conditions. The maximum velocities were not significantly different among the three scavenger types.

## **Additional Process Performance Considerations**

Additional process performance considerations are summarized below.

Formation of NO<sub>x</sub> compounds -- The nitrite-based scavenger produced approximately 15 to 29 ppmv of total nitrogen oxides in the treated natural gas. The oxides are believed to be made up primarily of nitric oxide, but it may be possible in some cases for the more corrosive nitrogen dioxide to be formed if oxygen is present in the inlet natural gas. 9

Formation of ammonia -- No significant formation of ammonia was observed with any of the scavengers tested during the field evaluation. However, it has been reported in the literature that ammonia may be formed by nitrite scavengers in applications where the inlet natural gas contains less than 0.5 percent carbon dioxide.<sup>9</sup>

Removal of sulfur compounds—No significant removal of organic sulfur compounds was observed with the triazine or nitrite scavengers. However, the nonregenerable amine scavenger appeared to remove all of the organic sulfur compounds (27 ppmv) from the inlet natural gas under the test conditions at the site.

Corrosivity -- Low to moderate corrosion rates were observed inside the carbon-steel scavenging towers based on short duration (30 to 90 days) weight loss tests with corrosion coupons. The triazine agent showed a rate of 3 mils/year (mpy), and the nonregenerable amine and nitrite both had rates of less than 1 mpy.

## **Capital and Operating Costs**

Table 6 summarizes the estimated scavenging treatment costs for the three representative liquid scavengers as experienced in this test program. These costs have been normalized to reflect treating 15 MMSCFD of gas at 1000 psig containing 19 ppmv H<sub>2</sub>S. These costs are approximate and based on operating cost data collected from the host site facility for their particular gas throughput and composition and current capital costs estimated by Radian. Capital

costs will be higher for plants with higher throughputs or operating pressures, and treatment costs per thousand standard cubic feet (MSCF) will rise with increasing H<sub>2</sub>S concentration. The capital costs are identical among the scavengers for this application based on the similar maximum superficial velocities that were observed during the field testing. Operating costs varied considerably based on differences in capacity, purchase cost, and frequency of tower changeouts.

The M.W. Kellogg Company, under contract to GRI, is developing a general scavenging process comparison and costing model which will incorporate cost information from this and other field data collection efforts.<sup>10</sup>

**Table 6**  
**Capital and Operating Cost Summary**

	Nitrite	Nonregenerable Amine	Triazine
Capital Cost <sup>a</sup>	\$464,000	\$464,000	\$464,000
Operating Costs:			
Scavenging agent <sup>b</sup>	\$64,600	\$147,600	\$153,300
Operating Labor	7,200	7,200	7,200
Maintenance	17,300	1,300	1,300
Tower changeout/disposal	12,600	18,400	18,400
Annual Operating Cost <sup>c</sup>	\$101,700	\$174,500	\$180,200
Amortization <sup>d</sup>	\$100,500	\$100,500	\$100,500
Annual Treatment Cost	\$202,200	\$275,000	\$280,700
Total Treatment Cost			
\$/MSCF	\$0.037	\$0.051	\$0.052
\$/lb Sulfur	\$23.30	\$31.70	\$32.40

<sup>a</sup> Based on a factored cost estimate for a 15 MMSCFD installation.

<sup>b</sup> Actual costs may vary depending on negotiated discount prices.

<sup>c</sup> Based on actual usages measured during this program and market prices.

<sup>d</sup> Based on six-year project life at 8% interest rate.

## **Waste Disposal Practices**

Spent scavenging agents from oil and gas exploration and production operations are exempt in most cases from the regulatory management requirements for hazardous wastes. This exemption allows for more available and cost-effective treatment and disposal options. Longer term, the viability of this exemption under federal and state laws is unknown. The elimination of the exemption would have the practical effects of restricting the disposal options available and increasing their cost. Therefore the cost of producing marketable natural gas for industrial and residential consumption would increase. Such an event would have a significant economic impact, and would make the development of alternate technologies, such as regenerable scavengers, a very high priority.

At the host site facility, the spent solutions were readily disposed of as nonhazardous exempt wastes using a local commercial class II underground injection facility. The host facility has also disposed of the nitrite scavenging solids separately from the liquids at a nearby Publicly Owned Treatment Works (POTW) which dewatered, encapsulated, and landfilled the solid material as a nonhazardous waste.

In general, all of the three scavenging agents had similar waste characteristics with the exception of the high solids content (> 1 %) for the spent nitrite and nonregenerable amine agents. All of the spent scavenging samples exhibited levels of benzene in excess of 0.5 mg/L. The source of this benzene is the natural gas at the host site, which has about 700 ppmv benzene (see Table 2). These high levels of benzene would cause these wastes to be classified as characteristically hazardous in cases where the exemption did not apply. Some potential was also noted for accumulation of toxic levels of metals, since some metals were detected in concentrations approaching the maximum concentration for nonhazardous wastes. All samples were found to be non-ignitable (following separation of the floating hydrocarbon layer) and nonreactive.

## **Health and Safety Considerations**

The nitrite, nonregenerable amine, and triazine scavengers included in this field evaluation are eye and skin irritants and require appropriate gloves and eye protection. Approved supplied air respirators may be required in cases where ambient concentrations exceed acceptable permissible exposure limits or when entering tanks. The host site personnel found that it was not necessary to enter the towers during changeout for any of the liquid scavengers.

The potential for benzene exposure was identified at the host site during tower changeouts. During the changeout procedure, the spent scavenging agents, along with a light condensate, were removed from the tower using a commercial vacuum truck. Fumes emitted from the vacuum truck exhaust vent and those fumes emitted while opening towers for inspection are potential sources of benzene exposure associated with the use of liquid scavengers. The potential exposure to benzene may not apply at sites with low benzene content in the natural gas.

Odor problems were noted with the use of the nonregenerable amine and triazine scavengers. Both of these spent scavenging agents have particularly disagreeable odors which were noticed while the towers were changed out. The host site has also experienced odor problems associated with glycol dehydrator vents downstream of the scavenging plant. The host site installed activated charcoal filters on one vent to control the odors.

### **FIELD EVALUATION OF A SOLID-BASED H<sub>2</sub>S SCAVENGER**

Field testing of a solid-based scavenging agent is currently in progress and nearing completion at a natural gas treating plant near Waco, Texas. The scavenging agent under evaluation is SulfaTreat<sup>®</sup>, which is an iron-oxide based scavenger. A description of this ongoing field evaluation is given in this paper along with some of the preliminary results. A complete set of results will be available after the evaluation is completed.

SulfaTreat<sup>®</sup> is a registered trademark of The SulfaTreat Company.

## **Description of Host Site Facilities**

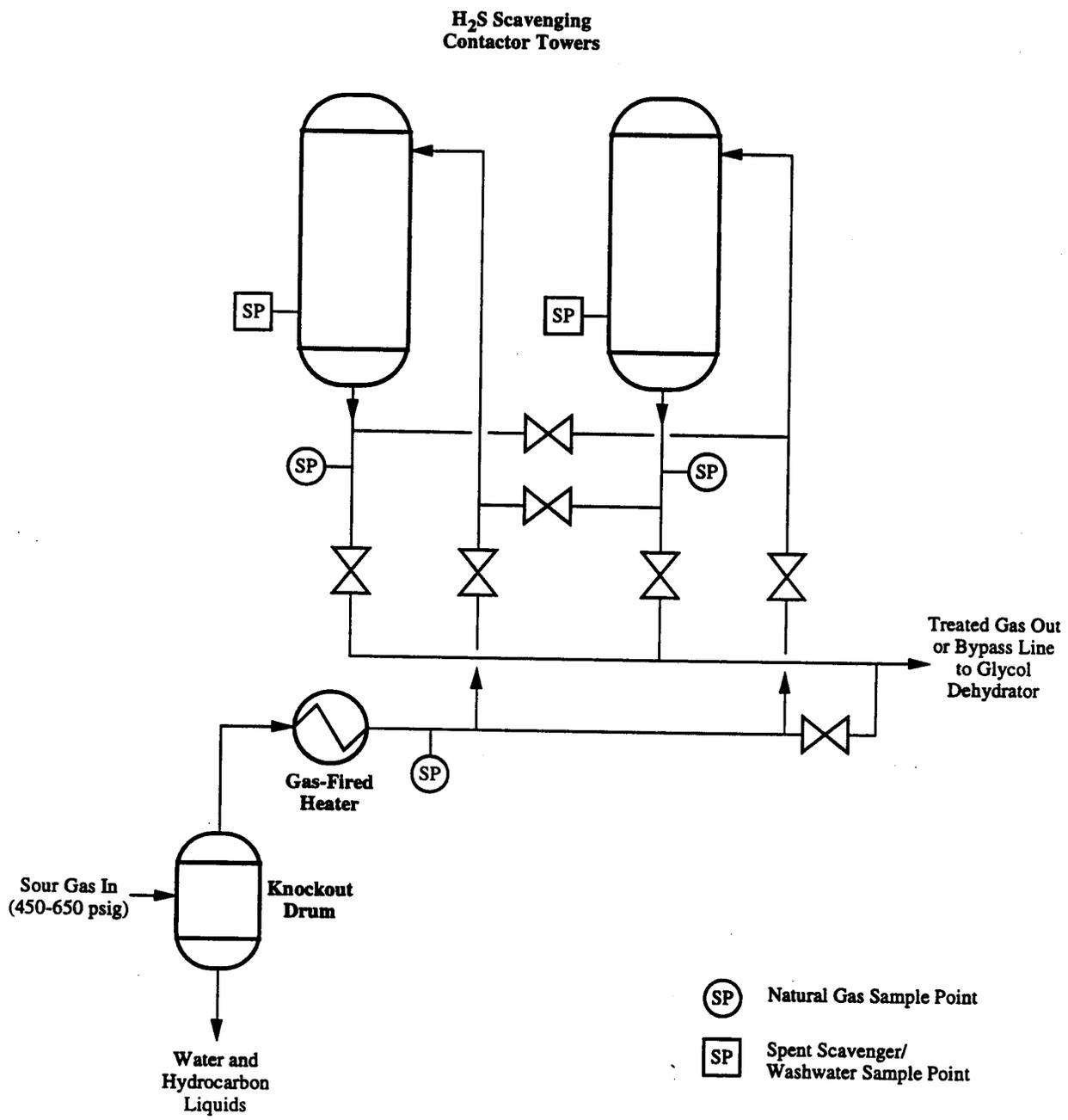
The solid-based scavenger is being evaluated at two separate gas treating facilities operated by the host company. Process flow diagrams are given for the two facilities in Figures 5 and 6.

Site one treats approximately 2 - 13 MMSCFD of natural gas with 5 - 10 ppmv H<sub>2</sub>S and 2 -3 % CO<sub>2</sub>. Natural gas enters the plant at 450-650 psig and flows through an inlet knockout vessel, a gas-fired heater, and then into the down-flow scavenging towers. Two towers are installed and can be operated in either a series (lead/lag) or parallel configuration.

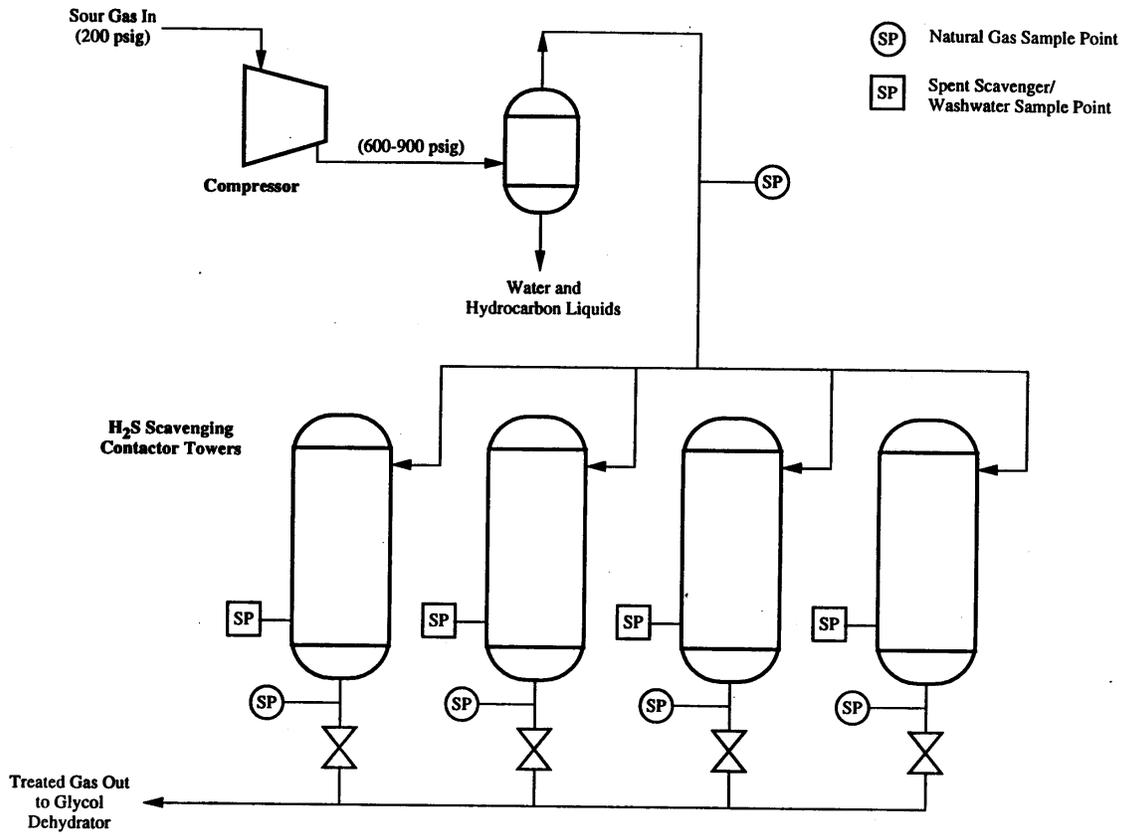
Site two treats approximately 2 - 17 MMSCFD of natural gas with 4 - 14 ppmv H<sub>2</sub>S and 2 % CO<sub>2</sub>. The gas is gathered at approximately 200 psig and compressed to 600 - 950 psig prior to scavenging treatment. The discharge gas from the compressors flows through an inlet scrubber to remove free liquids and then into four treating towers installed in a parallel configuration. Waste liquids from the towers at both sites can be removed from a drain valve in the bottom of the tower.

## **H<sub>2</sub>S Removal Performance**

In general, the solid-based scavenger has been used successfully to produce a treated sales gas meeting or exceeding the H<sub>2</sub>S specification of 4 ppmv. In many cases the H<sub>2</sub>S concentration was below detectable levels using stain tubes. The sales gas produced by blending treated gas from new towers as well as from towers nearing breakthrough averages 1.5 ppmv (based on a preliminary examination of approximately one year of data).



**Figure 5. Site One Flow Diagram for Field Evaluation  
of a Solid-Based Scavenger**



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**Figure 6. Site Two Flow Diagram for Field Evaluation of a Solid-Based Scavenger**

## **Description of Tower Changeout Procedures**

The operators at the host facilities remove the spent scavenger from the towers by washing the material out as a slurry. The operators begin by isolating and depressurizing the vessel. After filling the vessel from the bottom with water to wet the scavenger, a 24-inch manway near the bottom of the vessel is opened. The spent scavenger is then washed out into a front-end loader positioned to catch the slurry as it flows from the tower. Water is also washed through the bed from a manway on top of the vessel. The bucket on the front-end loader saves to separate the solid material from the excess wash water which overflows from the bucket to a wastewater collection sump. Each load of spent scavenger collected is deposited in an open area to air-dry. The fresh scavenger is loaded from 2,000 lb sacks through a manway on top of the vessel using a crane to hoist the sacks into position.

The total time required to change out a 37.5 inch inside diameter tower containing 7,000 lbs (approximately 100 ft<sup>3</sup>) is about 8 hours. This includes 2 hours to isolate, depressurize, and fill the vessel with water, 4 hours to wash the spent scavenger out; and 2 hours to load the vessel, conduct leak-checks and put the tower back in service. The changeout requires one vacuum truck with operator, one front-end loader with operator, one crane with operator, and three field hands. The crane and crane operator are needed for less than one hour to complete the loading of the fresh scavenger.

The time required to replace the spent scavenger in the towers will vary depending on the ease of removal, the size of the tower, the type of wash equipment used, and the experience of the crew. For example, the crew at the host site facility typically uses a water sprayer operating at approximately 80 to 90 psig and 60 gallons per minute (gpm). The vendor of the scavenging agent has recommended using a higher water pressure and flow rate to reduce the tower changeout time.

## **Additional Data to be Gathered**

Data are also being collected in several other areas:

- Scavenging capacity;
- Bed pressure drop characteristics;
- Water balance analysis;
- Sulfur compound removal;
- Pyrophoric behavior of the spent scavenger;
- Waste characterization and disposal practices;
- Health and safety requirements; and
- Capital and operating costs.

The capacity of the scavenger (measured in terms of pounds of sulfur removed per pound of fresh scavenger) is an important performance parameter in establishing the treatment cost. The capacity will be estimated through reconciliation of natural gas flow data, inlet and outlet H<sub>2</sub>S concentration data, and the amount of scavenger per tower. The capacity will also be measured directly (if possible) through analysis of spent scavenger samples for total sulfur content.

The bed pressure drop will be measured over a range of flow conditions and bed ages. Preliminary results indicate pressure drops of less than 5 psi under normal operating conditions. Inlet and outlet natural gas samples will be characterized to determine whether the bed is operating under saturated moisture conditions and to assess the removal of organic sulfur compounds.

The temperature of the spent scavenger also will be monitored after it is removed from the tower to evaluate the potential for spontaneous combustion of the spent material. In one initial test, temperature measurements of up to 117 °F were recorded in the spent scavenger pile while the ambient temperature was 61 ~F. During another test under similar ambient conditions, the material showed no detectable temperature rise when removed from the tower. Additional testing is planned to characterize further the potential for pyrophoric behavior.

Samples of the spent scavenger are also being analyzed to determine their waste disposal characteristics. Preliminary results indicate the importance of air-drying the spent scavenger. Air-dried samples leached benzene in concentrations less than 0.5 mg/L, whereas samples of the wet scavenger collected during the tower changeout had levels above 0.5 mg/L (0.5 mg/L is the regulatory level established for determining benzene toxicity under 40 CFR Part 261).

Capital and operating costs for the solid agent will also be developed based on information gathered at the host site facility. A normalized treatment cost for the solid-based agent will be developed which will include costs for tower changeouts, scavenging agent replacement, operating and maintenance labor, and waste disposal.

### **FIELD EVALUATION OF LIQUID-BASED H<sub>2</sub>S SCAVENGERS IN DIRECT-INJECTION APPLICATIONS**

Direct injection involves pumping the scavenging agent directly into the sour natural gas pipeline with a positive displacement pump. The scavenging agent may be introduced into the line using 1) a simple pipe connection, 2) an extended "quill" tube to deliver the agent to the center of the pipe, or 3) atomization nozzles. The gas and scavenging agent mix together either under open flow conditions or with static mixing devices. In some cases, the tortuous flow paths through process equipment may be used to enhance the mixing. Following the mixing and reaction, the liquid (and potentially solid) reaction products are removed in a downstream knockout device.

Direct-injection scavenging with liquid absorbents has several potential advantages over the conventional tower applications with liquid or solid scavengers, including:

- No pressurized tower contactor required;
- No costly changeout of towers required;
- Less potential for foaming/carryover problems; and
- Potential for lower chemical usage requirements.

However, direct-injection scavenging has several process characteristics which require careful consideration by the gas producer. The performance of direct-injection scavenging is more difficult to predict than for tower-based processes, in part because of the complexities involved in the two-phase mixing of scavenging agents with natural gas in the pipeline. Direct injection processes must operate over a wide range of gas/liquid ratios, gas velocities, atomizer/spray nozzle types, and injection pump designs (e.g., pulse flow or continuous flow). Trial and error design appear to be typical with these systems. Performance in some cases may be limited by contact time available in the existing piping system. High-pressure injection pumps may also lead to higher maintenance costs and reliability problems. The potential for solids deposits to accumulate in pipelines is also a concern.

Despite these potential concerns, direct-injection remains an attractive alternative to some gas producers because of the potential for reduced chemical costs and that the capital cost of a pressurized tower contactor is avoided. GRI is currently evaluating liquid-based H<sub>2</sub>S scavengers in direct-injection applications and these results are scheduled to be published at the next GRI sulfur recovery conference to be held in September 1995.

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