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Utilization of Low-Quality Natural Gas
A Current Assessment

Final Report

W.P. Acheson
J.H. Hackworth
S. Kasper
H.G. McIlvried

January 1993

Work Performed Under Contract No.: DE-AC21-90MC27346

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
K & M Engineering and Consulting Corporation
Washington, D.C.

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EXECUTIVE SUMMARY

The objective of this report is to evaluate the low quality natural gas (LQNG) resource base, current utilization of LQNG, and environmental issues relative to its use, to review processes for upgrading LQNG to pipeline quality, and to make recommendations of research needs to improve the potential for LQNG utilization. LQNG is gas from any reservoir which contains amounts of nonhydrocarbon gases sufficient to lower the heating value or other properties of the gas below commercial, pipeline standards. For the purposes of this study, LQNG is defined as natural gas that contains more than 2% carbon dioxide, more than 4% nitrogen, or more than 4% combined CO_2 plus N_2. The other contaminant of concern is hydrogen sulfide. A minor contaminant in some natural gases is helium, but this inert gas usually presents no problems.

Much of the information in this report on reserves of LQNG has been extracted from a data base developed for GRI by Energy and Environmental Analysis, Inc. (EEA). EEA's objective was to evaluate the chemical composition of natural gas deposits in the lower-48 states and provide as complete a list as possible of reserves by reservoir and composition. Reserves were divided into three categories: proven reserves; probable extensions to proven reserves; and expected, but as yet undiscovered, reserves. Slightly over one third of the proven reserves fall into the category of low quality.

There are several reasons for removing contaminants from natural gas in addition to raising the heating value. For example, if carbon dioxide level is too high, carbonic acid can form and cause corrosion in transmission lines. Both carbon dioxide and nitrogen can increase the Wobbe index beyond specifications, if their concentrations are too high. Hydrogen sulfide is not only poisonous and ill-smelling, but it also adds sulfur dioxide to the atmosphere when it is burned. Water has to be removed to prevent condensation in pipelines and possible freeze-up of equipment in cold climates.

Rather than direct combustion for power generation, upgrading by means of blending or gas treatment is the only widely practiced disposition of LQNG at the present time. In general, the choice is whether to upgrade the low-quality natural gas from a well or simply to shut it in, and this is highly site situational. In addition to the usual market factors, the decision depends on the size of the resource and its composition and location with respect to prospective users or pipelines.

Essentially all natural gas streams need to be dehydrated and desulfurized. Carbon dioxide is frequently removed at the same time as hydrogen sulfide, but nitrogen is only infrequently removed.

Because natural gas is such an important commodity, a great deal of effort has been spent developing processes for upgrading it. Dehydration is usually accomplished using glycol, although adsorbents, such as molecular sieves, are also used. Acid gas removal processes usually utilize absorbents. Amine solutions are frequently used. Acid gases form weak chemical compounds with the amines; these compounds are decomposed by heat to regenerate the amines. Other processes use physical absorbents, such as methanol. Because of the lack of a chemical bond between the solvent and the acid gas components, solvent based processes are generally more energy efficient. Nitrogen is not often removed. When it is, it is usually through either cryogenic processing or pressure swing adsorption.

Once sulfur is removed from LQNG there are essentially no barriers to its use without further processing. The major contaminants are nitrogen and carbon dioxide, neither of which is currently classified as an air pollutant, although carbon dioxide is a greenhouse gas and could be regulated in the future. The biggest obstacle to direct utilization of LQNG appears to be transportation of the LQNG to a power plant or else transportation of the produced electricity, if the power plant is located at the gas field. Although a vast distribution system exists for transporting natural gas, it would be difficult to transport LQNG through this system which has been set up to handle high quality gas. If the power plant is located at the gas field, then the cost of transporting the electricity may make the plant noncompetitive.

Plant investments and operating costs were estimated for a number of cases involving removal of nitrogen only, carbon dioxide only, and both carbon dioxide and nitrogen. In all of these cases, plant size was in the range of 80-120 million SCFD of raw gas. All the nitrogen and carbon dioxide removal cases were assumed to be saturated with water and had either 0.6% or 2.7% H_2S. Required selling price of gas was calculated on a no cost basis for the raw gas to H_2S removal.

Total capital investment for removing H_2S from 100 million SCFD of gas is in the range of $12-19 million, and the required selling price of gas varies from 12 to 16¢/MSCF (without a credit for by-product sulfur). Appendix D includes graphs showing the cost of H_2S removal as a function of gas feed rate. A special case was evaluated for low gas flows to ascertain the potential for utilization of small sour gas sources at isolated locations. For 5×10^6 SCFD of gas with 770 ppmv H_2S, a gas price of 70¢/MSCF was calculated for a plant with a capital cost of $2.2 million.

The nitrogen removal cases covered a range of nitrogen contents of 6 to 25%. For cryogenic removal, investment was in the range of $21-33 million, and the required selling price of gas was in the range of 32-46¢/MSCF (gas price growth rate equal to the rate of inflation). Pressure swing adsorption using molecular sieves proved to be somewhat more expensive, with investments running from

\$27-31 million and required selling price in the range of 42-50¢/MSCF (gas price growth equal to the rate of inflation).

For the CO_2 removal cases, concentration in the raw gas ranged from 4 to 15%. For membrane separation, investment was in the range of \$9-17 million, and required selling price varied from 20-30¢/MSCF (gas price growth equal to the rate of inflation). Investment and operating costs for amine based processes were very similar to those for membranes (\$9-12 million and 22-25¢/MSCF, respectively, on same gas price growth basis). One case was evaluated for removing both nitrogen (25%) and carbon dioxide (6%). For the cases with either N_2 or CO_2 removal only, H_2S content was assumed to be 0.6%; but for the combined removal case, H_2S level was 2.7%. Investment was \$55 million, and required gas price was 53¢/MSCF. This investment includes the investment for H_2S removal, whereas the investments for the other cases do not include H_2S removal, although operating costs do include H_2S removal costs. This explains why this investment is high relative to the other cases.

The conclusion from this economic evaluation is that, although at current gas prices, gas processors cannot afford to do much in the way of upgrading LQNG, purification costs are reasonable, and a modest improvement in prices will allow a significant portion of the LQNG resource to be upgraded using existing technology.

On the basis of the above conclusion, a major new effort to develop new upgrading technology does not appear to be justified, although some studies are justified. For example, development of improved CO_2 absorbents would improve costs; also, improved membranes could prove to be very useful. With current N_2 removal processes, it is really the methane that is removed from the nitrogen, rather than the nitrogen that is removed from the methane. Economics should improve if a preferential absorbent or adsorbent for N_2 could be developed.

1.0 INTRODUCTION

1.1 Background

Low-quality natural gas (LQNG) is gas from any reservoir which contains excessive amounts of nonhydrocarbon gases sufficient to lower the heating value or other properties of the produced gas below commercial, pipeline standards. The most common contaminants are nitrogen, carbon dioxide and hydrogen sulfide. Other contaminants that occur less frequently in small concentrations are helium, argon, hydrogen, and oxygen. Water is not taken to be a factor in the quality of the gas, because it occurs in essentially all raw natural gas streams to one degree or another and has to be removed in any case. Since hydrogen sulfide is poisonous and its combustion products are atmospheric pollutants, it must also be removed to extremely low levels before the gas can be utilized.

In general, there are no quantitative, universal standards on what constitutes an "excessive" amount of any contaminant. In other words, there is no set standard for natural gas in commerce, and the controlling factors are current market forces and economic constraints. Each pipeline sets its own standards which must be met by anyone wishing to inject natural gas into that pipeline. Quality criteria are discussed in more detail below. However, for the purposes of this study, we will define low quality natural gas as natural gas that contains more than 2% carbon dioxide, more than 4% nitrogen, or more than 4% combined CO_2 plus N_2. These criteria correspond with those used by Hugman et al.[1] in their survey of the natural gas resource made for the Gas Research Institute (GRI) which is discussed further below.

1.2 Objectives and Scope

The objectives of this survey are to identify and analyze the potential for wider utilization of our low-quality natural gas resources.

There are three types of natural gas production: (1) "associated gas" from wells that are drilled and produced primarily for oil; (2) "wet gas" from gas wells that produce substantial amounts of hydrocarbon condensate; and (3) "nonassociated gas" from wells that produce mostly natural gas with perhaps some condensables but no more than minor amounts of oil. In 1988, nonassociated gas accounted for 82% of all the gas produced in the United States. Since the markets for petroleum and condensate will control the production of these fuels without primary regard to the quality of the co-produced gas, the area of major concern in this study is non-associated gas production in the U. S.

1.3 The Low Quality Natural Gas Resource

Low quality natural gas is defined as gas with more than 2% carbon dioxide, more than 4% nitrogen, or more than 4% carbon dioxide plus nitrogen. This resource can be divided into the following four classifications, depending on the quantity of the carbon dioxide and nitrogen contaminants it contains:

1. Gas with more than 2% CO_2 but 4% or less N_2
2. Gas with more than 4% N_2 but 2% or less CO_2
3. Gas with 2% or less CO_2 and 4% or less N_2 but with more than 4% CO_2 plus N_2
4. Gas with more than 2% CO_2 and more than 4% N_2

Much of the information in this report on reserves of LQNG has been extracted from a data base[1] developed for GRI by Energy and Environmental Analysis, Inc. (EEA). EEA's objective was to evaluate the chemical composition of natural gas deposits in the lower-48 states and provide as complete a list as possible of reserves by reservoir and composition. Reserves were divided into three categories: proven reserves; probable extensions to proven reserves; and expected, but as yet undiscovered, reserves. The main source of compositional data for the EEA data base was information compiled by the U. S. Bureau of Mines. EEA obtained reserve estimates from state or district level reserve-to-production ratio reports.

The EEA data base divides total natural gas reserves into three categories: proven, probable, and undiscovered. Proven reserves are net proven reserves as of 1988. Probable reserves represent reserve growth than can reasonably be expected to occur as a result of extensions to existing fields, while undiscovered reserves are potential reserves resulting from discovery of anticipated new fields. The EEA data base estimates (in trillions of standard cubic feet) of the reserves in these three categories are shown in the Table 1-1.

Table 1-1

ESTIMATED NATURAL GAS RESERVES

Category	Total Reserves, Tcf
Proven	136
Probable	157
Undiscovered	377
Total	670

This table indicates that the estimated probable reserves are about equal to the proven reserves, and the estimated undiscovered reserves are somewhat greater than the sum of proven plus probable reserves.

Figure 1-1 shows a plot of cumulative reserves vs. nitrogen content, Figure 1-2 shows a similar plot of cumulative reserves vs. carbon dioxide content, and Figure 1-3 show a plot of cumulative reserves vs. nitrogen plus carbon dioxide content. Figures 1-4 to 1-6 show information on proven reserves plotted in a slightly different format. In these figures, the percent of proven reserves with N_2, CO_2, or N_2 plus CO_2 contents less than the indicated amount is plotted against the N_2, CO_2, or N_2 plus CO_2 content. These figures show that most of the reserves have acceptable quality and that the percentage of reserves that falls into the LQNG classification is relatively low. Since the bulk of the natural gas reserves have less than 20% impurities, Figures 1-1 to 1-6 are limited to this range, so that the graphs may be more easily read. Additional plots of reserves versus impurity content are presented in Appendix C.

Another way of presenting the reserves data is shown in Figures 1-7 and 1-8. These figures relate to the portion of the proven reserves of natural gas which are classified as low quality because of high nitrogen or carbon dioxide contents. Figure 1-7 plots the percent of the proven reserves which are low quality because of high nitrogen content against the nitrogen content. Thus, this figure shows that, of the proven reserves which are low quality because they contain more than 4% nitrogen, 40% have less than 16% nitrogen, and 98% have less than 25% nitrogen.

Figure 1-8 presents similar data for proven reserves which are low quality because of carbon dioxide content. This figure shows that, of the proven reserves which are low quality because they contain more than 2% carbon dioxide, 90% have less than 10% carbon dioxide, and 98% have less than 25% carbon dioxide. This further confirms

Figure 1-1

RESERVES VS. NITROGEN CONTENT

Lower 48 States

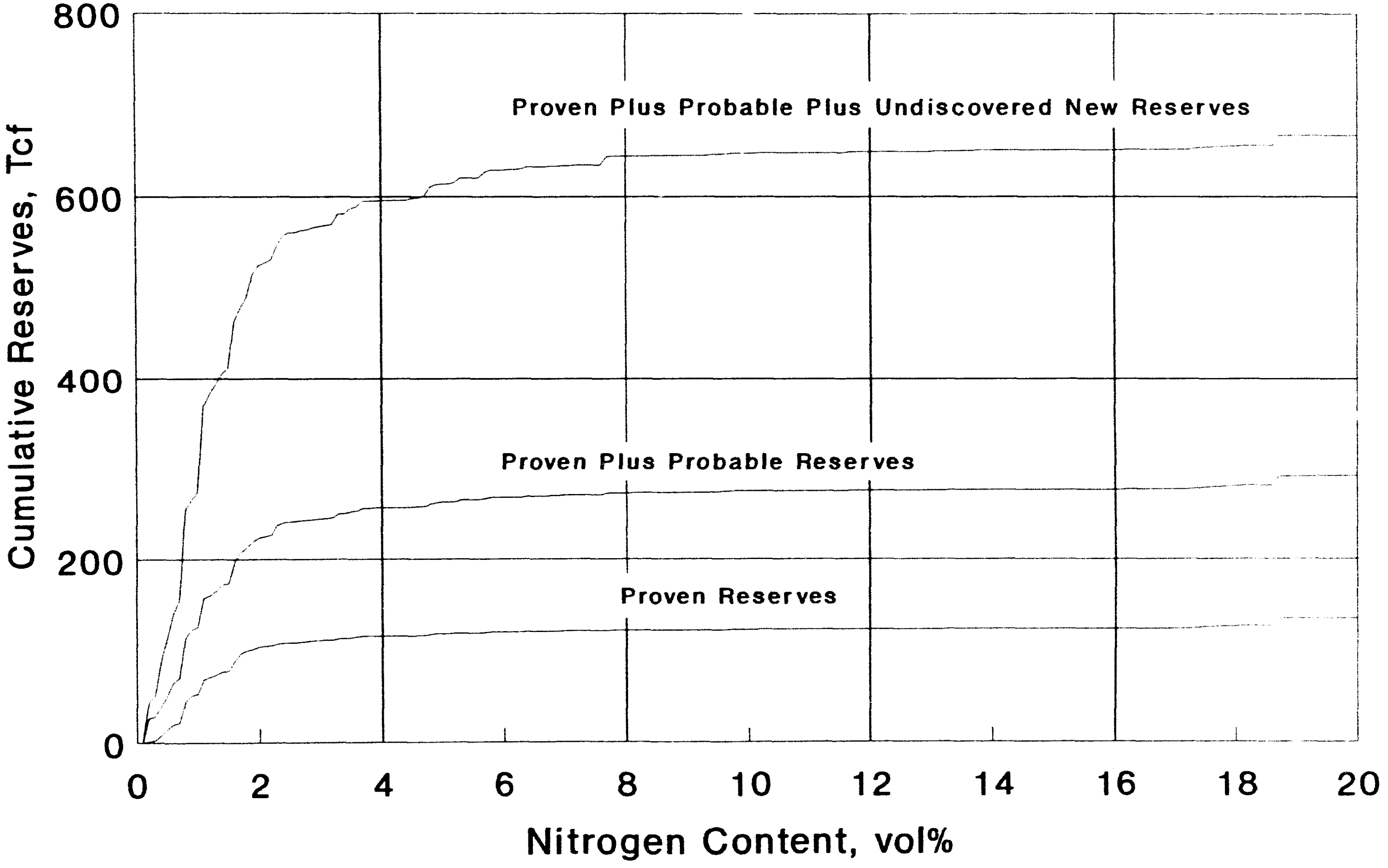


Figure 1-2

RESERVES VS. CARBON DIOXIDE CONTENT

Lower 48 States

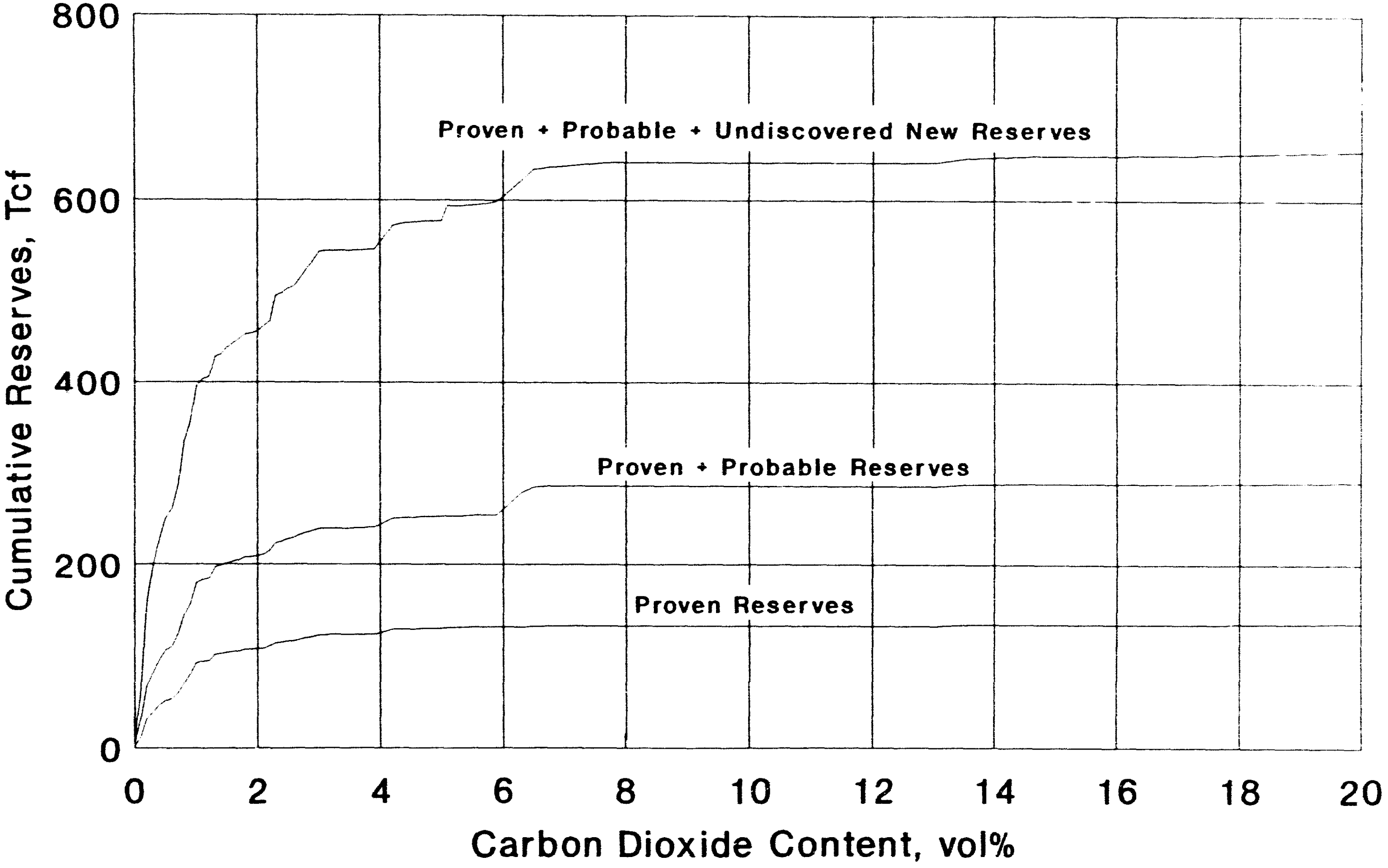


Figure 1-3

RESERVES VS. NITROGEN PLUS CARBON DIOXIDE CONTENT

Lower 48 States

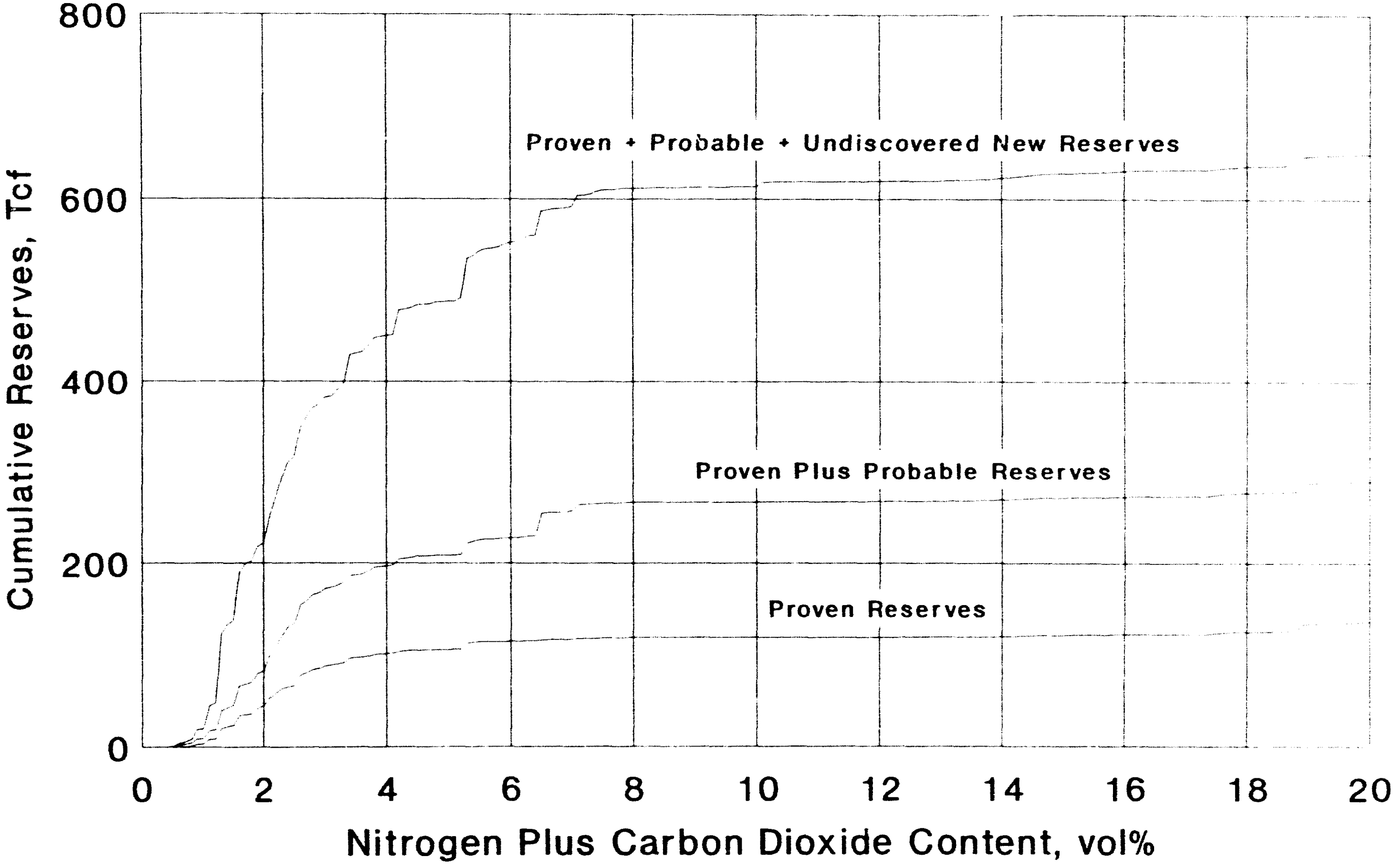


Figure 1-4

PROVEN RESERVES VS. NITROGEN CONTENT

Lower 48 States

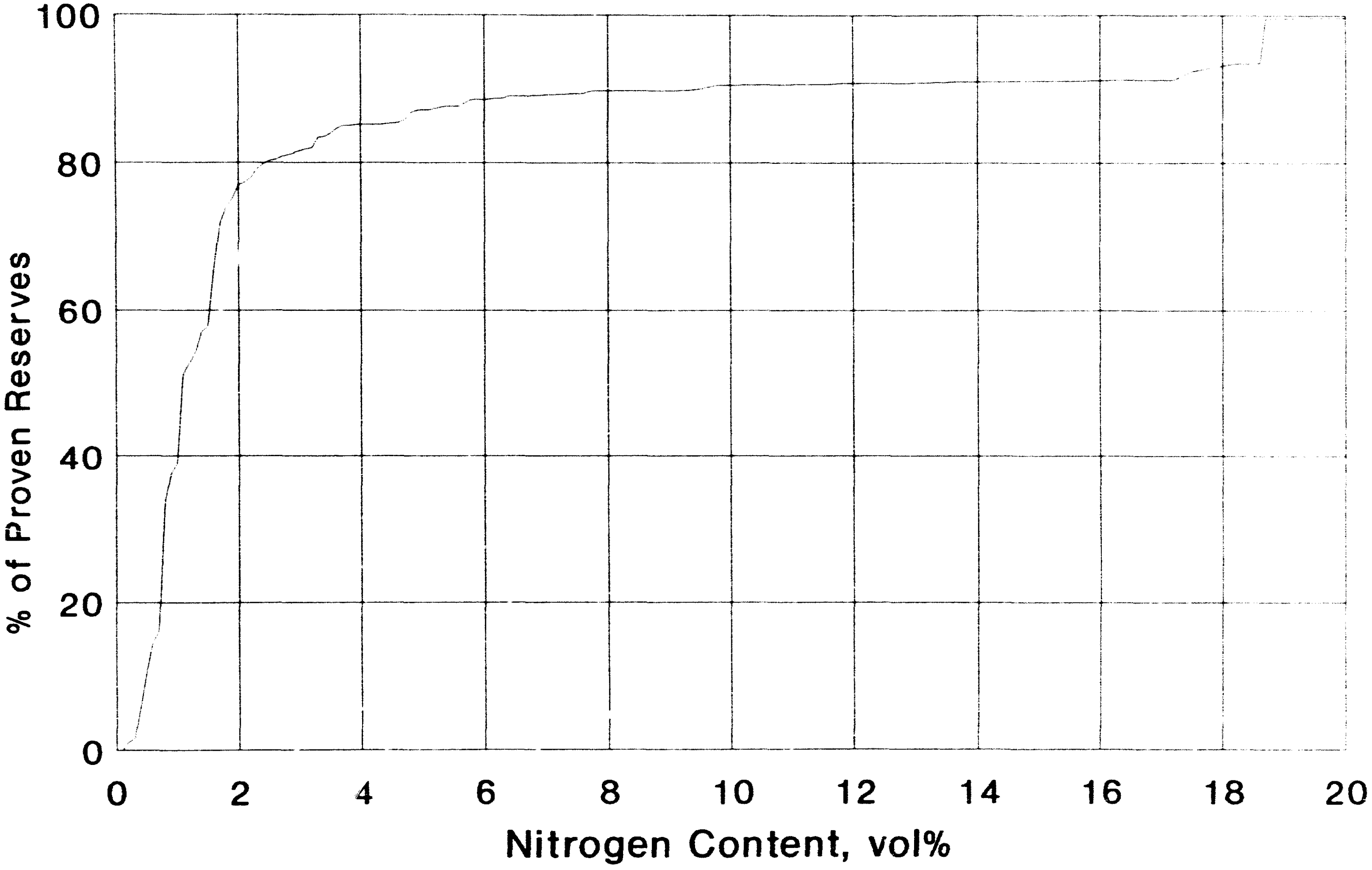


Figure 1-5

PROVEN RESERVES VS. CARBON DIOXIDE CONTENT

Lower 48 States

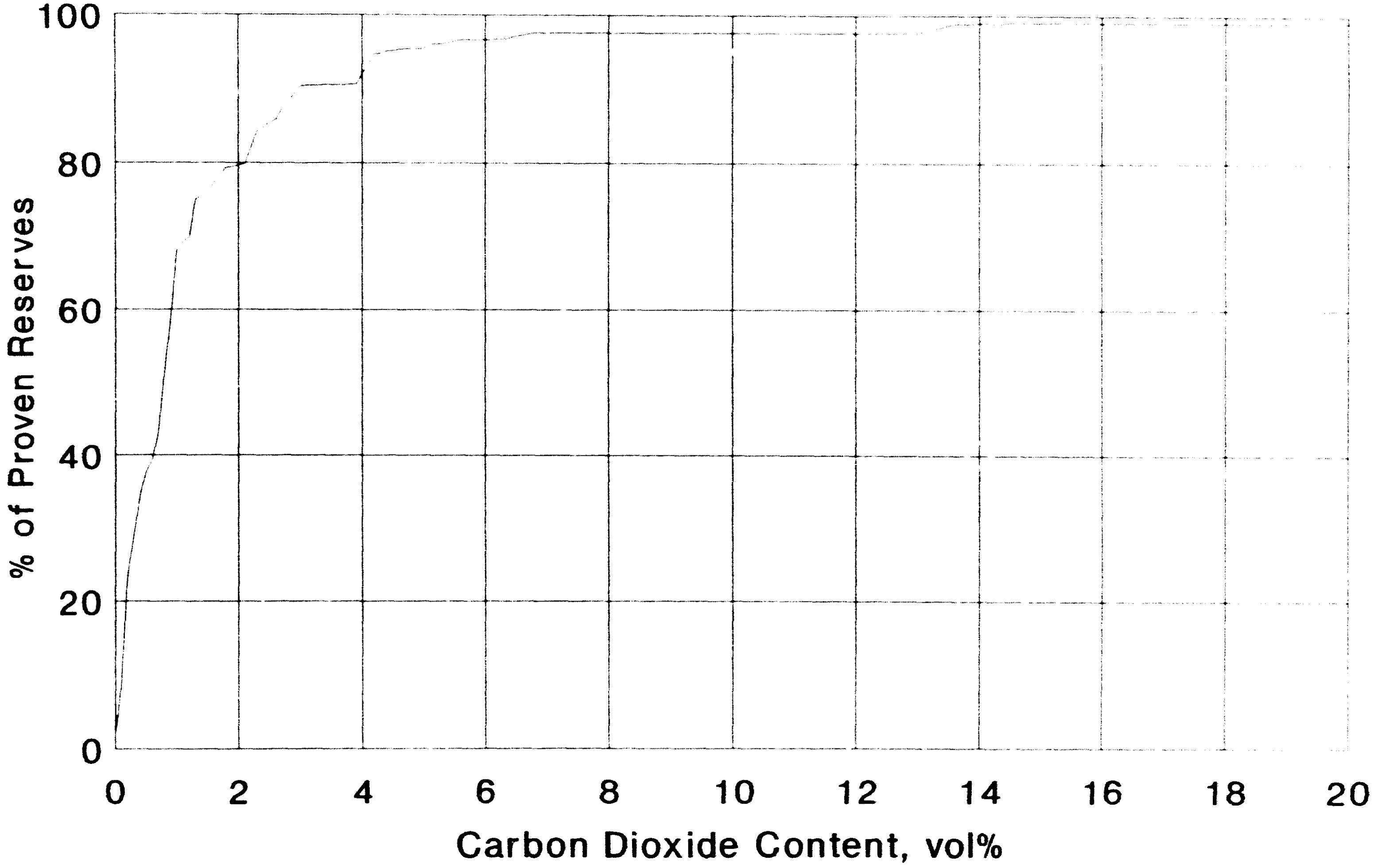


Figure 1-6

PROVEN RESERVES VS. CO_2 PLUS N_2 CONTENT

Lower 48 States

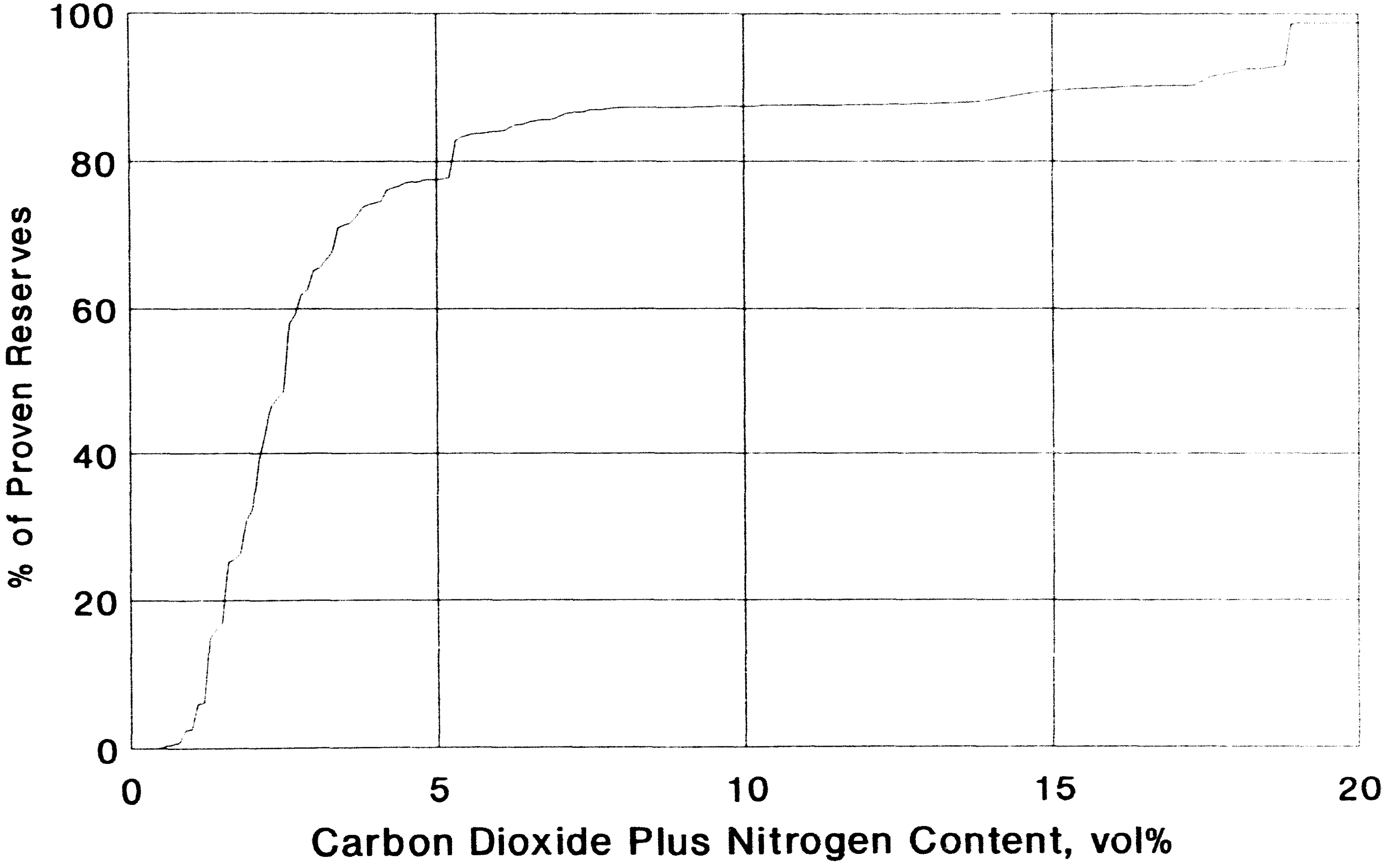


Figure 1-7

PROVEN LQNG RESERVES VS. N_2 CONTENT

Lower 48 States

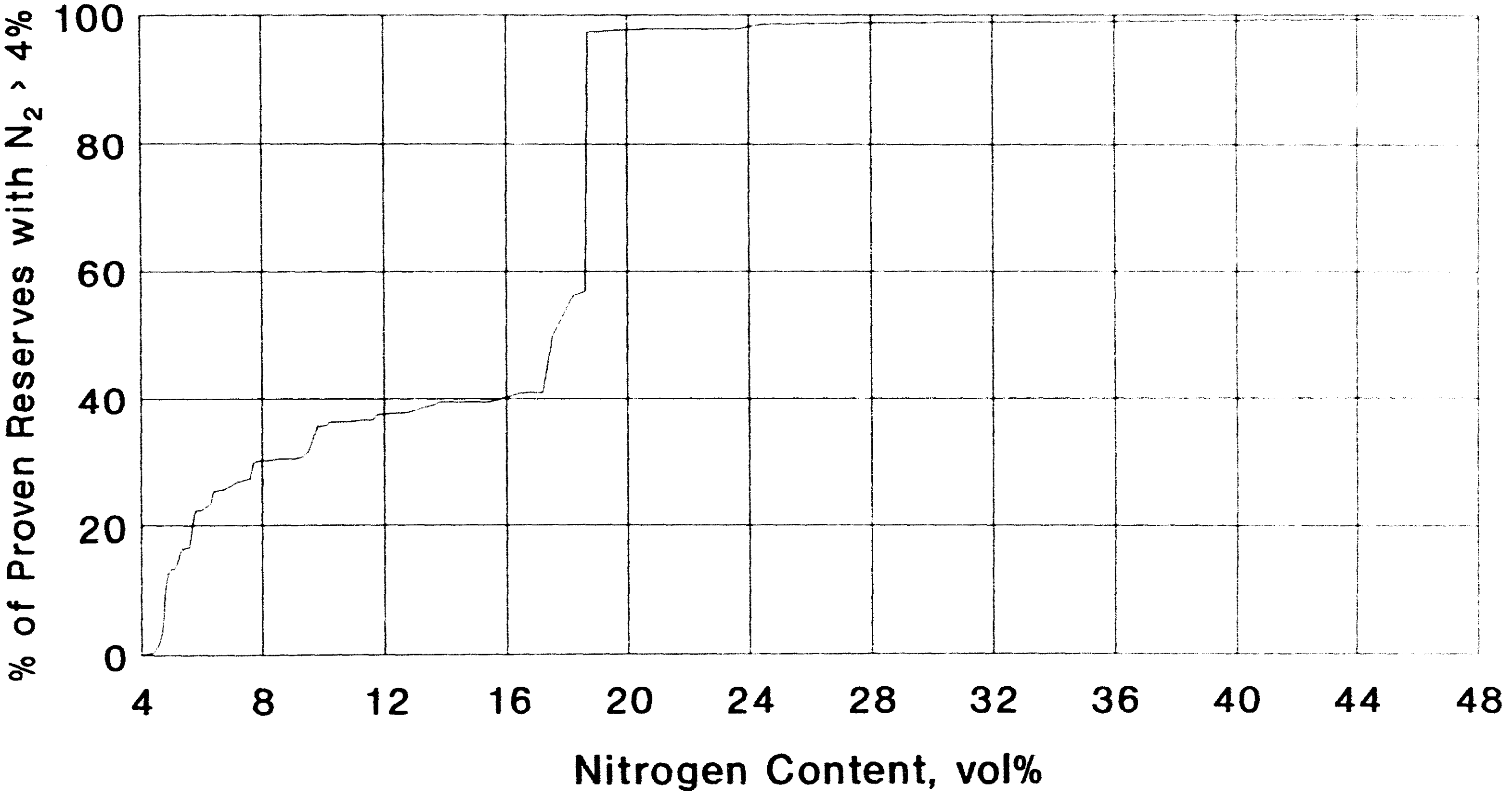
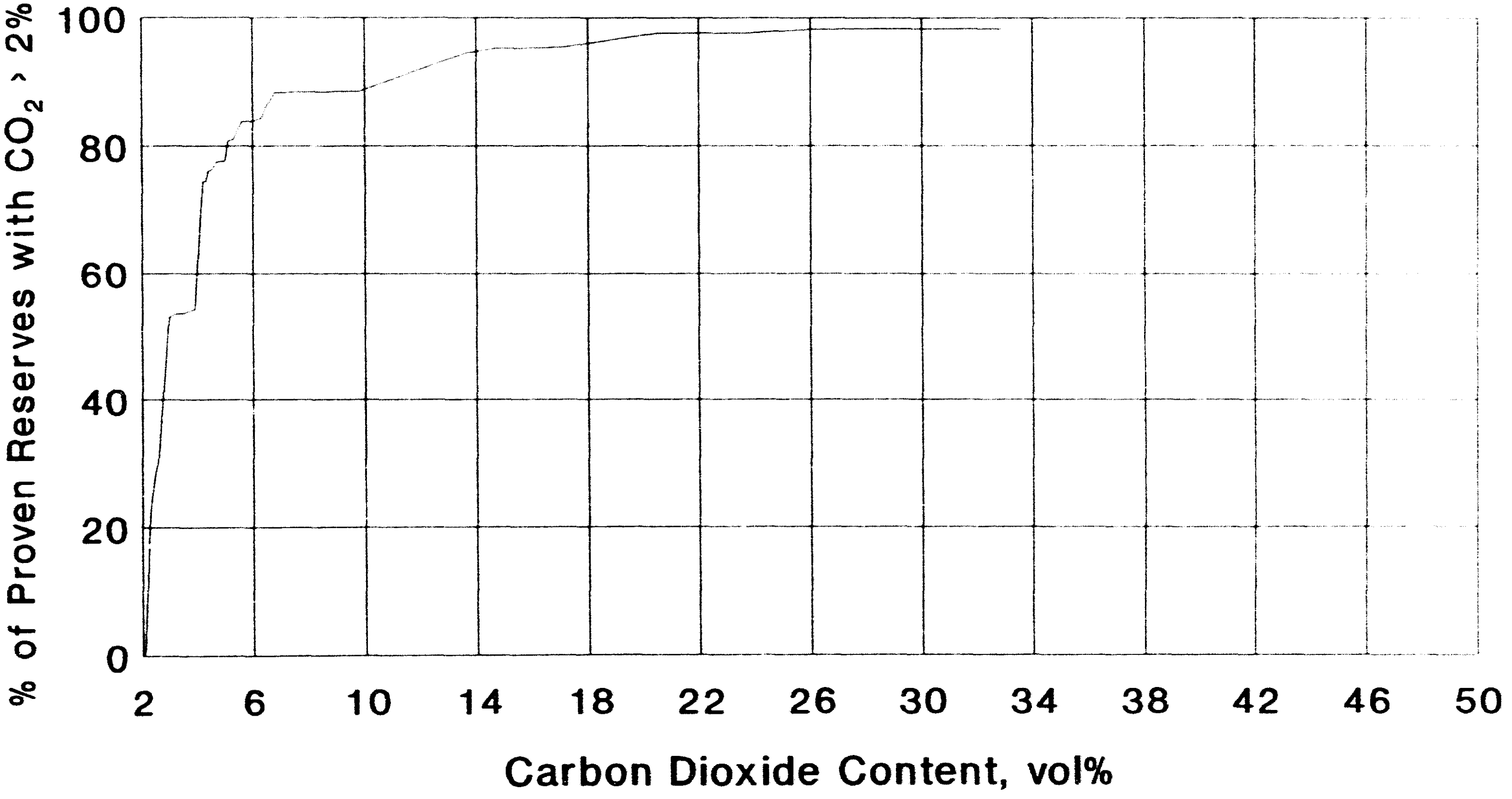


Figure 1-8

PROVEN LQNG RESERVES VS. CO_2 CONTENT

Lower 48 States



the conclusion that the bulk of the LQNG reserves have only moderate amounts of impurities.

Further analysis of the EEA data base provides the breakdown shown in Table 1-2 of LQNG reserves by classification for each of the three categories.

Table 1-2

RESERVES OF NATURAL GAS CLASSIFIED ACCORDING TO CONTAMINANT LEVEL

	Low Quality Natural Gas, % of Reserves				
Category	$>2\%$ CO_2 $\le 4\%$ N_2	$\le 2\%$ CO_2 $>4\%$ N_2	$\le 2\%$ CO_2 $\le 4\%$ N_2 $\ge 4\%$ CO_2+N_2	$>2\%$ CO_2 $>4\%$ N_2	Total LQNG
Proven	18.6	13.1	1.0	1.6	34.3
Probable	33.7	8.0	0.7	1.8	44.3
Undiscovered	31.4	7.2	0.4	3.1	42.0
Total	29.4	8.6	0.6	2.5	41.1

Approximately 41% of the total (proven plus probable plus undiscovered) natural gas reserves are low quality. The reserves in both the first and third of these classifications (i. e., reserves with less than 4% N_2) can be converted to high quality natural gas by the removal of CO_2, which is relatively easy to accomplish. Thus, nearly 60% of the 34.3% of proven reserves which are low quality can be upgraded by CO_2 removal alone, leaving only 14.7% of proven reserves that cannot be relatively easily converted to pipeline quality gas. For probable reserves, only 9.8% cannot be upgraded to high quality by CO_2 removal; and for undiscovered reserves the figure is 10.3%. Therefore, only about 11% of total reserves cannot be upgraded by acid gas removal alone.

A further portion of reserves will be only moderately above the 4% allowable limit for N_2, and at least some of this gas can be blended off with low N_2 natural gas. For example, a 6% N_2 natural gas could be blended 50-50 with a 2% N_2 gas to give a 4% N_2 gas, or a 10% N_2 gas could be blended 25-75 with a 2% N_2 gas to give a 4% N_2 gas.

Approximately 75% of the proven reserves have N_2 contents equal to or less than 2%, while approximately 5% of the proven reserves have nitrogen contents over 4% but less than 10%. Thus, the possibility of blending off gas with 10% or less N_2 would seem to be good. In some cases, even higher N_2 gas might be blended. Assuming that gas with 10% or less N_2 can be disposed of by blending, less than 10% of proven reserves would fall into the problem category of not being readily utilizable within the existing technology base at current prices. However, with price improvement, much of the problem 10% would become utilizable with existing technology.

With probable and undiscovered reserves, the situation is even more favorable. According to the EEA data base, only about 3% of probable reserves are estimated to contain more than 10% N_2, and only 1% of the undiscovered reserves will contain more than 10% N_2. For probable reserves, 75% will contain 2% or less N_2, and 80% of undiscovered reserves will contain 2% or less N_2. If these estimates are correct, it indicates that for the foreseeable future, most natural gas reserves can be brought to market by acid gas removal plus blending, if the N_2 content is too high.

The implication of the foregoing analysis is that little, if any, new technology is necessary to permit utilization of the great bulk of U. S. natural gas resources.

1.4 Pipeline Quality Criteria

There are no fixed, industry-wide standards for pipeline quality natural gas, nor are most standards governmentally regulated. Instead, quality criteria are set by contract between the gas supplier and the purchaser, which is generally a pipeline transmission company. Nearly all raw gas has to be treated in one way or another in order to meet pipeline specifications. Economics is the underlying criterion that determines whether a particular gas source will be processed and marketed or whether it will be shut in as uneconomical. The levels of diluents or contaminants that can be economically removed in order to market a raw gas source profitable are discussed in the next section. These limits vary widely depending on location and market factors. Pipeline standards[2] are discussed below.

In essentially all natural gas contracts, there is a stated minimum calorific value along with other specifications related to the end-use of the gas as a fuel. Natural gas delivered to consumers in the U. S. is remarkably uniform in most areas of the nation, falling in the range of 1030-1080 BTU/SCF. Limits are also normally placed on various nonhydrocarbon diluents or contaminants as well as tolerances on physical properties, such as gas specific gravity. These limits may be adjusted somewhat for specific locations, climates, or markets.

The contaminants limits (2% carbon dioxide, 4% nitrogen, or 4% combined, with less than 4 ppm hydrogen sulfide) used in the GRI study quoted above on the extent of LQNG resources are generic in the sense that they would probably meet the major provisions of most transmission company specifications. However, variations may apply in specific cases, and additional considerations may enter into the specifications as discussed next.

1.4.1 Water

Any gas must be dried to minimize corrosion and prevent freezing in the pipelines, as well as to remove water vapor as a diluent. However, in contrast to nitrogen and other diluents, water is not a quality-determining factor in the sense of affecting whether or not a gas well can be produced profitably. At least some water will be produced with the gas from any reservoir, and drying must be carried out as a matter of course in any case. The usual standard for transmission pipelines is that the dew-point at line pressure must be below a specified temperature.

1.4.2 Hydrogen Sulfide

Because hydrogen sulfide is so toxic, a strict, maximum limit of 4 ppm or 1/4 grain/100 scf is normally set for transmission line gas. This is a necessary safety precaution in case of leaks or other accidental emissions from any transmission, distribution, or end-use facility. Moreover H_2S-containing gas, when burned, produces sulfur dioxide, a pollutant. Thus, if the gas is to be sold, it is mandatory, not optional, to remove the hydrogen sulfide. Processes to remove hydrogen sulfide are well developed so that it is generally technically feasible to meet the 4 ppm standard, although possibly not economically so.

Such strict composition limits obviously cannot apply to the gas being sent to treatment plants, where the H_2S is removed. However, such gathering system pipelines are usually short and are subject to stringent safety standards and oversight to prevent corrosion and leaks.

1.4.3 Carbon Dioxide

Some older pipeline contracts specify a 2 mol% maximum for carbon dioxide; however, many newer contracts accept only 0.5-1.0% CO_2. This is based on the need to limit corrosion due to carbonic acid, which requires keeping the partial pressure of CO_2 below about 16 psia at transmission line pressure. If the gas is to be processed to recover natural gas liquids (NGL), the maximum limit on CO_2 may be set at 1% in order to protect the mole-sieve absorbents used in many such plants. If the natural gas is to be compressed to

3000-3500 psi for use as motor vehicle fuel, the carbon dioxide level may not be allowed to exceed 0.25-0.5%. Were it not for corrosion, a considerably higher upper limit might be acceptable, determined only on the basis of end-use. However, burner operation can be affected above 3-4% CO_2, and with certain types of burners the flame may begin to "lift off" the burner tips.

1.4.4 Nitrogen

Since nitrogen does not contribute to corrosion or safety problems, fairly substantial amounts can be tolerated in pipeline quality gas. More than 4 mol%, however, is usually enough to begin to degrade the performance of the natural gas as a fuel and to violate commonly set specifications on the gas specific gravity or Wobbe Index*. Even when such specifications are not imposed, larger amounts of nitrogen will generally cause the gas to fall below the specified BTU value per SCF.

1.4.5 Helium

If the natural gas is not being processed in order to extract helium as a product, helium is lumped with nitrogen as an inert diluent. Being inert, He does not need to be removed for safety or environmental reasons. Fairly high levels of helium can be acceptable, ranging up to 1%. However, in addition to contributing to the total inerts, helium can influence the gas density significantly and, thus, affect whether or not the gas meets specifications on gas density or Wobbe Index. Since helium occurs only in

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* The Wobbe Index is equal to the gross heating value of the gas in BTU/scf divided by the square root of the gas specific gravity. It is related to the rate of heat release of a burner with a fixed diameter orifice.

very small concentrations in the majority of reservoirs, it is not commonly a factor in gas quality.

1.4.6 Oxygen

A maximum limit of 100 ppm oxygen is currently a standard commonly imposed by transmission companies. (It is possible that this may be lowered to 50 ppm in the future.) It has been discovered that 100-300 ppm oxygen can cause corrosion problems under mill-scale on the interior of steel pipes. This effect is enhanced by moisture but occurs even when the gas is dry. In addition, oxygen can react with hydrogen sulfide or mercaptans at high pressure to form polysulfides, which may react adversely with brass and copper alloy parts in the downstream distribution system. However, this effect does not occur when the H_2S is limited to 4 ppm.

1.4.7 Health Hazards

Rarely, other hazardous contaminants are found in the natural gas produced from certain locations. Some gas in Arizona and New Mexico has been found to contain traces of arsenic, but only at concentrations that are below health safety limits. Wells in the area are now routinely watched for arsenic contamination.

Mercury vapor has been detected at low concentrations, below health safety limits, in some Arizona and Mew Mexico gas wells. Although not in high enough concentration to be a health hazard, mercury has been found to pose a processing problem. If it is present in gas sent to an LNG plant, mercury can seriously affect the cryogenic units. These systems often contain many parts made of aluminum, and mercury can cause aluminum to crack. This difficulty was first discovered in German LNG plants which processed natural gas from the Gronigen field in the Netherlands; this gas has the highest concentration of mercury yet found anywhere in the world. The feed streams to these plants are now continuously monitored for mercury.

When mercury is detected, it is not difficult to remove, since effective absorbents exist, and the feed gas can be routed through stand-by absorber units. One such adsorbent is impregnated granular activated carbon, which is reported[3] to be able to reduce mercury concentrations to levels of less than 1 ppbv at operating temperatures from 50-150°F and pressures up to 1000 psig.

Radon is a contaminant in some natural gas streams[4], and even though radon is relatively common, there is little possibility of human exposure to radioactivity from radon or its decay products in natural gas. Radon occurs in concentrations that vary widely from location to location. Measurements of radon activity[5] in samples of natural gas from wells in the U. S. varied from 1 to 1450 picoCurie/L. Although radon is dangerous when inhaled, it is not dangerous when contained within steel pipes or vessels, the walls of which are sufficient to absorb the emitted radiation. The Occupational Safety and Health Administration (OSHA) does not regulate radon. EPA recommends (but does not regulate) a maximum annual-average exposure of 4 picoCurie/L inside any structure. Radon would not be a substantial hazard around a drilling rig unless the well were in a high-radon area and one were somehow continuously exposed to gases evolving from the drilling mud system.

Radon has, however, been found to concentrate in natural gas liquids, and its decay products are known to collect in films and scale on the interior of pipelines carrying gas and condensate. Thus, the greatest threat from naturally occurring radioactive materials (NORM) appears to be in connection with clean-out operations on pipelines and gas plant equipment. The wastes from such operations are not exempt from hazardous waste regulations and should be measured for possible radioactivity. If the wastes are radioactive, regulations pertaining to the handling of radioactive sources may apply, and this will affect how the waste can be discarded.

1.5 Criteria for Upgrading

At least half of the more than 17 trillion scf (TCF) of natural gas currently produced annually in the U. S. is processed to remove contaminants other than water in order to bring it up to pipeline standards and/or recover associated products. These products include ethane and heavier hydrocarbons, natural gas liquids (NGL), sulfur, and sometimes helium. In certain situations, carbon dioxide or nitrogen are recovered for use in enhanced oil recovery (EOR).

The maximum concentration of contaminants that can be removed economically varies considerably and depends on the magnitude of the gas supply, its location, especially in relation to existing treatment plants, pipelines, or markets, and gas price and demand. Also, the feasibility of upgrading may depend on whether the gas contains heavier hydrocarbons sufficient to justify processing to recover them. These factors are so variable that it is not possible to state specific, across-the-board criteria for the concentration levels of nonhydrocarbons that make the gas worth treating or that render it uneconomic to produce. The economics of each case have to be evaluated individually.

Nevertheless, by examining the quality of the gas streams being treated in existing U. S. gas plants, it is possible to indicate the range of contamination levels that are currently being processed. Data[6] compiled by the Gas Research Institute (GRI) on the feed gas to 500 existing gas treatment plants are shown in Table 1-3. These data indicate that approximately 80% of the natural gas treatment plants in the country process feed gas streams containing less than 1% hydrogen sulfide. Only about one-tenth of the plants handle streams with more than 10% H_2S.

Table 1-3

HYDROGEN SULFIDE CONTENT IN RAW GAS FEED TO PROCESSING PLANTS

Feed Stream H_2S Concentration Range	% of Plants
0 - 1%	80
1 - 5%	6
5 - 10%	4
> 10%	10

Similarly, more than half of the plants in this data set currently handle feed streams containing less than 5% carbon dioxide (see Table 1-4). Fewer than 10% of the processing facilities treat natural gas streams with more than 20% CO_2. Carbon dioxide would typically have to be reduced in these plants to the 1-2% range to meet pipeline standards. In general, these data suggest that upgrading gas with more than 20% carbon dioxide is not often profitable. There are notable exceptions, such as plants associated with EOR facilities that process streams that contain 50% or more CO_2 in order to recover the CO_2 for reinjection.

Table 1-4

CARBON DIOXIDE CONTENT IN RAW GAS FEED TO PROCESSING PLANTS

Feed Stream CO_2 Concentration	% of Plants
0 - 2%	33
2 - 5%	23
5 - 10%	21
10 - 20%	14
> 20%	9

The presence of more than a few percent nitrogen in the LQNG is more likely to render the gas unprofitable to produce, because substantial denitrification normally requires cryogenic processing, which is relatively costly. As noted, there are exceptions depending on special circumstances. For example, it may be possible to blend the high-nitrogen stream with an above-specification stream; cryogenic processing may be justified, if the gas contains enough NGL's; or the nitrogen may be required onsite for EOR. Consequently, what constitutes too much nitrogen in LQNG is generally situational.

2.0 CURRENT STATE OF THE ART IN LQNG UTILIZATION

2.1 Overview

Upgrading by means of blending or gas treatment, rather than direct combustion, such as for power generation, is the only widely practiced disposition of LQNG at the present time. In general, the choice is whether to upgrade the low-quality natural gas from a well or simply to shut it in, and this is highly situational. In addition to the usual market factors, the decision depends on the size of the source and its composition and location with respect to prospective users or pipelines.

The circumstances under which upgrading or other uses may be feasible are discussed in the following sections according to the kinds of contaminants found in the gas.

2.2 Essential/Minimum Upgrading Requirements

2.2.1 Dehydration

As noted previously, essentially all gas wells produce at least some water. The amount depends on the reservoir conditions and the flowing temperature and pressure. Gas/liquid separators are used at each production site to remove liquid water (and oil or condensate when present). Water vapor must also be removed to bring the dew point of the gas stream down to an acceptable level. This level is normally specified contractually and may vary according to whether the gas is being delivered to a processing plant or to a transmission pipeline. It must be low enough to avoid freezing, hydrate formation, and corrosion in the delivery system pipeline. Corrosivity of the gas stream will also be influenced by the level of acid gases present. Regardless of the quality of the gas, some type of dehydration process will almost certainly be necessary. Specific dehydration processes are discussed in Section 4.2.

2.2.2 Hydrogen Sulfide Removal

If the LQNG contains appreciable levels of hydrogen sulfide, it is essential that it be treated because of the dangerous and corrosive nature of this contaminant. It has been noted that pipeline-quality gas must contain less than 4 ppm of hydrogen sulfide. If the LQNG is being delivered to a relatively short gathering system for a processing plant, somewhat higher levels may be tolerated, dictated mostly by concerns over corrosion. Even if the gas were to be directly burned on site, hydrogen sulfide removal would most probably be necessary to meet emission requirements. If hydrogen sulfide is present, gas treatment for its removal is indispensable, no matter what other constituents the gas may contain. Again, specifics on appropriate processes are discussed in Section 4.

In the rest of this section, the discussions therefore assume that the low-quality natural gas is processed to remove water and hydrogen sulfide as necessary.

2.3 LQNG High in Carbon Dioxide

2.3.1 With Methane as the Principal Product

If the LQNG from a given field is high in carbon dioxide but also contains a high enough concentration of methane, it is possible to produce the gas for its methane content and vent the carbon dioxide. The feasibility of upgrading such a gas to pipeline standards depends, of course, on whether the carbon dioxide is below a certain break-point concentration, say in the range of 5-25%. The specific break-even point, or maximum concentration of carbon dioxide that can be removed profitably, can be higher if some or all of the following circumstances apply:

(1) The gas field is large, and the production rate and reserves are large enough to justify the capital investment required for the processing plant.

(2) Appreciable amounts of gas liquids can be recovered.

(3) The LQNG contains H_2S, and a gas treatment plant is justified on the basis of H_2S removal. In this case, the acid gas removal plant may be able to remove the carbon dioxide at only a small incremental cost.

Environmertal considerations may provide a counter influence based on the fact that carbon dioxide is a greenhouse gas, and for this reason it may be undesirable to vent it.

2.3.2 With Carbon Dioxide as the Principal Product

If the CO_2 concentration is high enough and there is a market for CO_2, it may be profitable to produce the low-quality gas for the carbon dioxide. In this case, the methane could not be vented, both because of environmental considerations and because of its sales value. Some portion of the gas might be burned to generate power for the process. The break-point concentration of carbon dioxide in this situation is likely to be rather high, perhaps 50-80%. Factors that would tend to increase the feasibility of LQNG production in this situation would include:

(1) Proximity to EOR projects requiring substantial quantities of carbon dioxide or to CO_2 pipelines feeding such projects.

(2) Valuable co-produced hydrocarbons.

(3) Absence of other sources of purer, larger volume supplies of carbon dioxide.

It should be noted that in several regions of the country, there are large natural reservoirs of nearly pure carbon dioxide which are being produced for use in EOR. Extensive systems of CO_2 pipelines have been developed for gathering and distributing this CO_2. It is unlikely that any LQNG CO_2 source could compete with the natural carbon dioxide wells in such areas.

2.4 LQNG High in Nitrogen

2.4.1 Blending

LQNG containing modest amounts of nitrogen, in some cases up to 15%, is most often handled by blending with high quality streams. This, of course, depends on the availability (proximity) of enough high quality gas to ensure that the mixture is low enough in inerts and high enough in BTU value. This can often be the situation in a gas processing plant which is supplied by several feed streams from different gas fields. In at least one location, a high-nitrogen field is located near a large-volume pipeline which has been willing to purchase the LQNG for a reduced price, pro-rated according to fuel value. In this particular case there are no other contaminants that require removal.

It becomes increasingly more difficult to dispose of nitrogen-containing LQNG streams by blending, as they increase in flow volume or nitrogen concentration. In such cases, the wells are likely to be shut in or abandoned.

2.4.2 Denitrification with NGL Recovery

If cryogenic processing of a nitrogen-containing LQNG stream is justified, which is generally only when substantial volumes of natural gas liquids can be recovered, then there is a possibility that the nitrogen concentration can be reduced concurrently. Other denitrification processes are also sometimes used, as described in Section 4.

2.4.3 Nitrogen Recovery for Reservoir Pressure Maintenance

There are situations where the nitrogen from a LQNG reservoir may be useful for EOR or pressure maintenance. The source and use would have to be close together, because transmission costs could otherwise be prohibitive. These situations appear to be somewhat fortuitous and may be relatively rare. Nevertheless, one successful example is the Amoco Production Company's Painter complex at La Barge, Wyoming[7].

2.5 Helium Recovery

At certain locations there is enough helium in the LQNG to make its removal at least marginally feasible. When the helium can be recovered along with saleable hydrocarbons, then the process may in fact be profitable. Processes for helium recovery are noted below. The difficulty is that helium is presently in over supply and has been for some time. In the past, the federal government purchased helium to establish a strategic reserve. This was filled long ago, and now government purchases are limited to replacing the relatively small volumes that are withdrawn. The commercial market for helium is not very large. The economic incentive for helium recovery appears to be weak at this time.

2.6 Use of LQNG for Power Generation

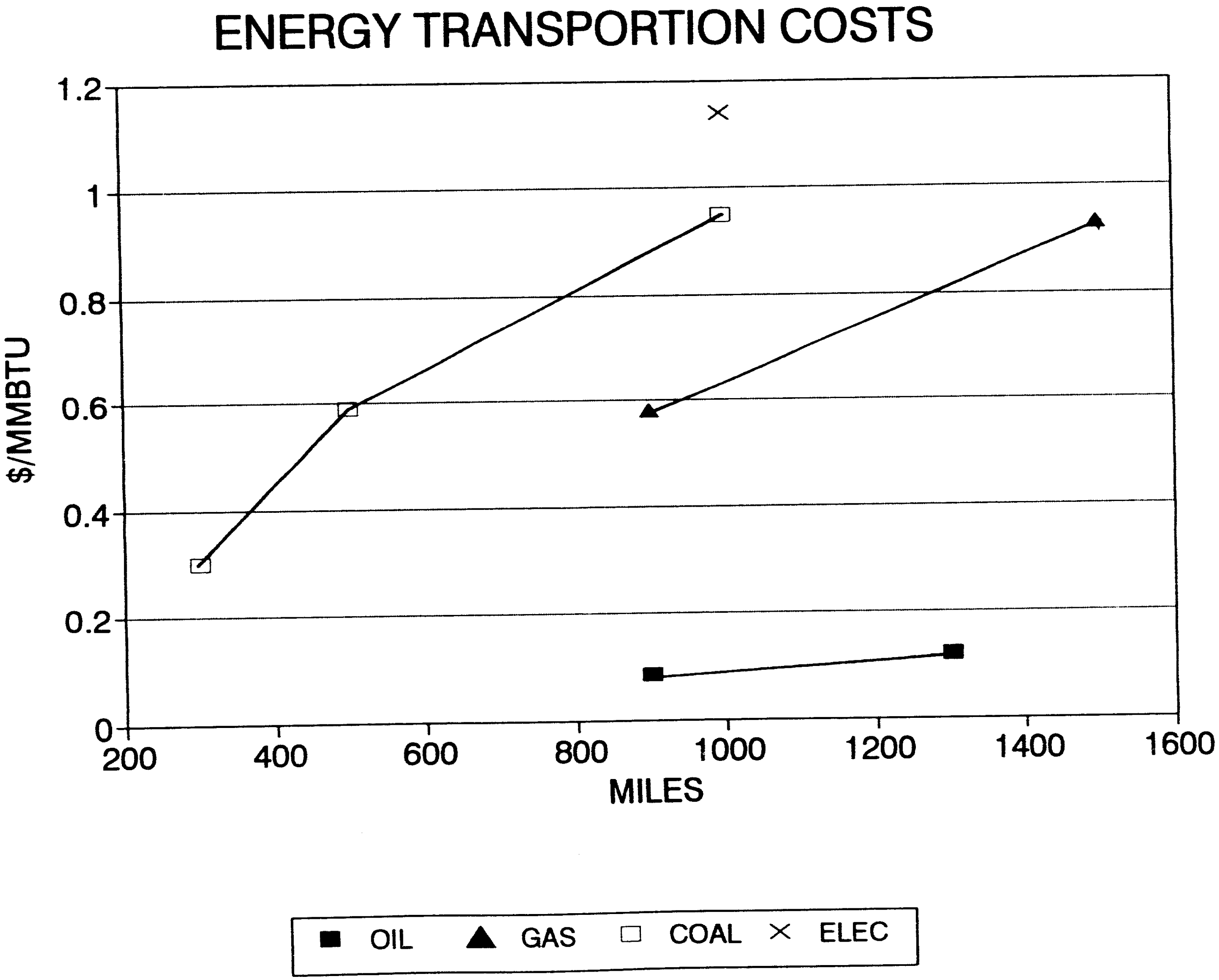
There are a number of options for using LQNG for power generation. Currently, LQNG is blended with higher BTU gases, thus entering the commercial pipeline system and finding its way into normal uses. There is, however, an obvious limit on the quantity of LQNG that can be used in this fashion. There is also some upgrading of gas to pipeline quality by means of nitrogen and carbon dioxide removal processes, as discussed in subsequent sections. The final option is to combust the LQNG for power generation, either at the production site or at a distant location, without removing the N_2 and CO_2.

The CO_2 and N_2 contents of LQNG do not pose a significant problem when considering combustion of natural gas for power generation. As has been reported[8], "Heavy-duty gas turbines have operated successfully, burning alternate gaseous fuels with heating values ranging from 300 to 3100 Btu/SCF lower heating value........ Most medium and high calorific value gases can be burned with existing natural gas fuel nozzle and combustor designs with little change (except NO_x emissions) in combustion performance."

Transportation cost is a big factor in comparing power generation at the production site vs. transportation of gas with or without N_2 and/or CO_2 removal to a distant using location. Figure 2-1 shows the comparative cost of transporting energy as oil, gas, and high Btu coal compared with transmission of generated electric power[9,10,11,12,13,14]. For comparison of transportation costs, a value of 10,000 Btu/kWh was used for electricity, based on the approximate Btu's of fossil energy required to generate a kWh of electricity.

As the nitrogen and carbon dioxide content of LQNG increases, the transportation cost on a $\$/10^6$ Btu basis increases. Figure 2-2 shows the relationship between the N_2 and CO_2 content and the Btu content of LQNG. As was pointed out in the discussion of the LQNG resource base, most of the LQNG resource contains less than 50% N_2 plus CO_2, which means its heating value is greater than 500 Btu/SCF. Returning to the transportation cost relationships of Figure 2-1, a 500 Btu/SCF gas would mean a doubling of the transportation cost, but even a doubling of gas transportation cost

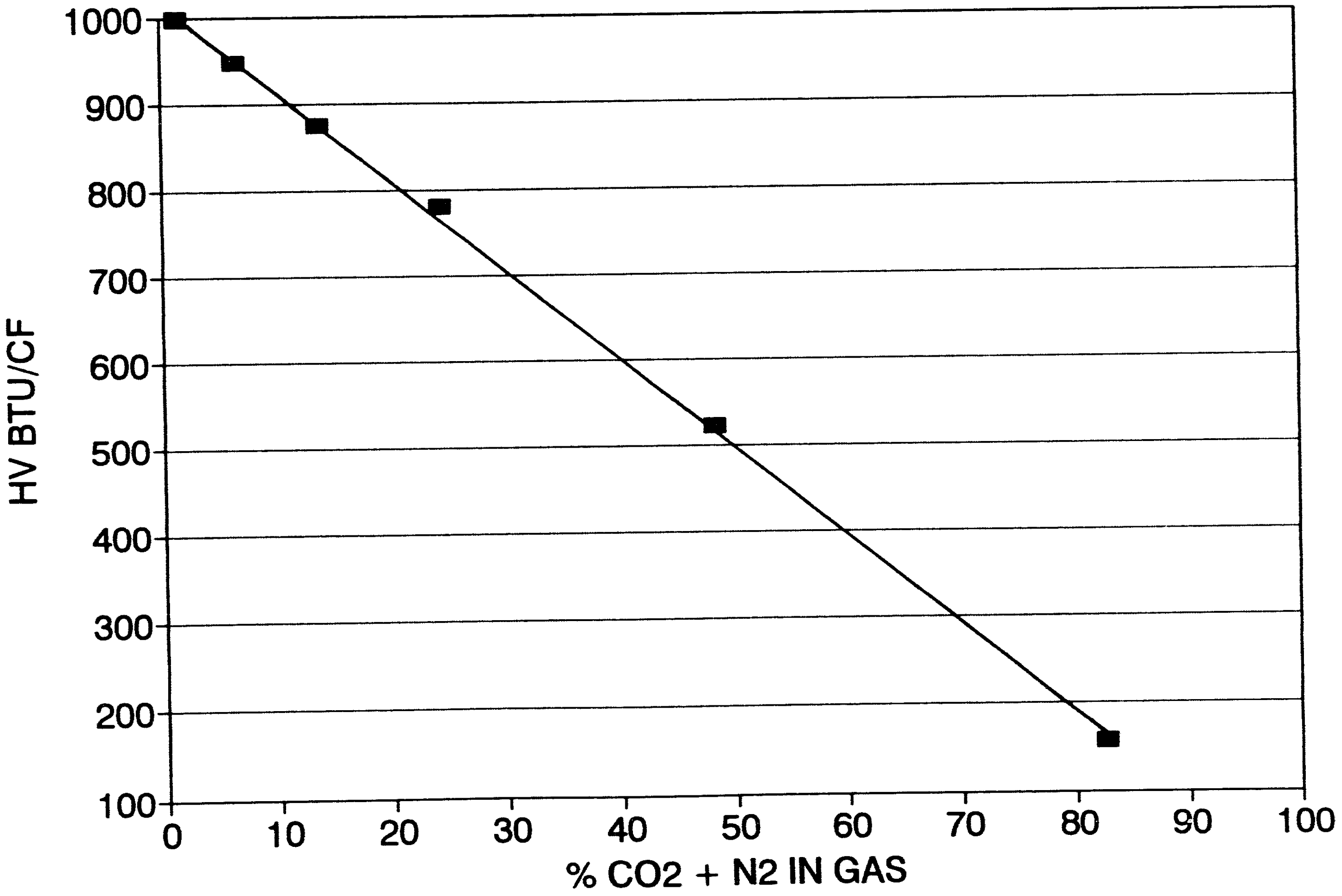
Figure 2-1



ENERGY TRANSPORTION COSTS

Figure 2-2

HEATING VALUE OF LQNG
vs GAS CONTENT



would still make gas transportation less costly than electricity transmission.

Removal of N_2 and CO_2 from LQNG will reduce the cost of transporting the gas, but for a LQNG with only moderate levels of N_2 and CO_2 (5-20%) the reduction in transportation cost will not come close to offsetting the upgrading cost. Thus, it could potentially be economically attractive to ship the LQNG without N_2 and CO_2 removal and burn it at the power generation facilities. This is not being done now because, in the first place, given current gas prices and availability, there is little market need for LQNG, whether upgraded or not. Even if gas prices were to improve, one obstacle that would face direct utilization of LQNG is transportation in the commercial gas pipeline network. It will be necessary to determine the feasibility and acceptability of doing this. In addition to working out how to ship a LQNG through the pipeline system, arrangements will also have to be made for storage of the LQNG, and that storage might have to be separate or at least only used by the utility.

From the standpoint of economics and use in a turbine, the use of LQNG that has not been upgraded appears to have possibilities. However the potential obstacles of transmission and storage need to be investigated thoroughly to determine if it is practically feasible and could be brought into being when the gas market makes the use of LQNG attractive.

LQNG could probably be successfully co-fired in a coal burning furnace for the reduction of NO_x, but this would require a special situation, since LQNG would not normally be available to a coal burning utility, and economics would probably not justify transporting the LQNG unless the gas field were nearby.

3.0 ENVIRONMENTAL CONSTRAINTS

This section will address the issue of whether existing and potential environmental regulations pose any barriers to the use of LQNG.

3.1 Contaminants

The major contaminants in low quality natural gas (LQNG) are:

Carbon dioxide (CO_2)
Hydrogen sulfide (H_2S)
Nitrogen (N_2)
Helium (He)

Other contaminants, such as COS, CS_2, or mercaptans, may be present in very small amounts, but are rare and need not be of general concern. The major contaminants are discussed in the following sections.

3.1.1 Carbon Dioxide

Carbon dioxide is one of the greenhouse gases, i.e., it traps infrared radiation in the atmosphere and thus tends to raise the earth's temperature. Although there is grave concern about this problem among many scientists, carbon dioxide emissions are not currently regulated. Thus, carbon dioxide can be removed from LQNG and exhausted to the atmosphere without violating any pollution regulations. Alternatively, the carbon dioxide could be left in the LQNG until the gas is burned, in which case the CO_2 would pass into the atmosphere in the flue gas; but again no pollution regulations would be violated.

At some time in the future, there is likely to be an effort to reduce carbon dioxide emissions, but this in not expected to occur until some time in the next century. The exact timing and the form of the regulations are hard to predict. Because of our very high reliance on fossil fuels, particularly for transportation, any regulation of carbon dioxide emissions will have a severe economic impact. For this reason, regulation will not come quickly. The timing will depend on the result of further studies of the greenhouse effect.

Carbon dioxide has a number of uses. It is being increasingly used for enhanced oil recovery projects. It is injected into oil reservoirs, where it dissolves in the petroleum and decreases viscosity, thus improving the flow of the oil to the production wells. This use is very desirable, since the CO_2 is reinjected and does not enter the atmosphere. Another use of CO_2 is in the production of dry ice. Although this is a valuable use of carbon dioxide, the CO_2 eventually ends up in the atmosphere, and the market is small relative to the potential availability of carbon dioxide from LQNG.

3.1.2 Nitrogen

Nitrogen is, of course, the major component of the earth's atmosphere, making up approximately 78%. Therefore, the nitrogen in LQNG can be exhausted to the atmosphere, either after being removed by some process, such as cryogenic processing or pressure swing adsorption (PSA), or in the flue gas from combustion of the LQNG. It is unlikely that emissions of nitrogen gas (N_2) will ever be regulated.

Like carbon dioxide, nitrogen can be injected into petroleum reservoirs to enhance oil recovery. However, nitrogen is less effective, and this is not seen as a major use for nitrogen. However, nitrogen can be used to repressure formations, when that is desirable.

3.1.3 Helium

As far as is currently known, helium is completely inert. It is not regulated and can be exhausted to the atmosphere. Thus, its presence in LQNG does not pose any problem from an environmental point of view. Helium has many uses, ranging from nuclear research to filling lighter than air balloons; and its major source of supply is various natural gas deposits. However, U. S. stockpiles are currently filled, so that He in LQNG is not currently likely to provide an incentive for the production of LQNG nor to be recovered when high helium LQNG is produced.

3.1.4 Hydrogen Sulfide

Of the contaminants in LQNG, only H_2S is currently regulated as far as air pollution is concerned. Hydrogen sulfide is one of the 189 chemicals listed in the Clean Air Act Amendments, for which emission limits will be developed by the EPA. Thus, once it is removed from LQNG, H_2S cannot be exhausted to the atmosphere. However, this does not present a significant problem, because the H_2S can readily be converted to other forms, such as elemental sulfur or sulfuric acid; and this is, in fact, what is being done with the hydrogen sulfide currently being removed from natural gas.

Hydrogen sulfide removal from gas streams has been practiced for many years, and a large number of very effective processes for lowering the H_2S content of gas streams to very low levels is commercially available. Some of these processes simultaneously remove carbon dioxide. Once recovered, the H_2S is usually converted to one of two products: elemental sulfur or sulfuric acid. Each of these materials is a major item of commerce with large and ready markets.

Elemental sulfur is usually produced by the Claus process, in which one third of the H_2S is oxidized to SO_2. The SO_2 is then reacted with the rest of the H_2S to form elemental sulfur. The chemistry is as follows:

$$2H_2S + 3O_2 \text{ ----> } 2SO_2 + 2H_2O$$

$$2H_2S + SO_2 \text{ ----> } 3S + 2H_2O$$

Alternatively, all the H_2S can be oxidized to SO_3, which is then reacted with water to form sulfuric acid. The chemistry is as follows:

$$2H_2S + 3O_2 \text{ ----> } 2SO_2 + 2H_2O$$

$$2SO_2 + O_2 \text{ ----> } 2SO_3$$

$$SO_3 + H_2O \text{ ----> } H_2SO_4$$

Both the above processes have been used extensively by industry and are at a high level of development. Properly designed plants, particularly those with secondary sulfur recovery on the tail gas from the primary plant, are capable of reducing sulfur emissions to very low levels which fully meet all present and anticipated air pollution regulations. Thus, the presence of hydrogen sulfide in LQNG does not present an environmental problem for the exploitation of these streams, since the technology for the removal of H_2S is highly developed and readily available. Of course, the economics of each situation will have to be evaluated, since removal of large quantities of H_2S can be expensive.

3.1.5 Methane

Although not a contaminant, methane is itself a greenhouse gas. In fact, it has several times the radiative forcing potential of CO_2, on a moles of carbon basis. Nevertheless, it is currently not regulated, largely because it is relatively inert from a smog forming point of view and because its regulation would pose significant problems for the coal mining industry. However, even though it is not now regulated, it is desirable to keep methane emissions as low as possible, especially since such losses represent an economic loss as well as a potential environmental problem.

Fortunately, most of the processes for the removal of the contaminants from LQNG are quite selective, so that losses of methane should be low. Any waste streams containing an appreciable amount of methane would be combusted to provide energy for the upgrading plant. This combustion would convert the methane to carbon dioxide before it was exhausted to the atmosphere. This would also convert any trace amounts of hydrogen sulfide to sulfur dioxide. Streams containing only small amounts of methane would be incinerated to convert the methane to carbon dioxide and the hydrogen sulfide to sulfur dioxide before being exhausted to the atmosphere.

3.2 Utilization of LQNG

There are basically three ways LQNG can be utilized: burn the gas directly; utilize it as feedstock to some process; or upgrade it to pipeline quality.

3.2.1 Direct Combustion

As discussed above, since the only component of regulatory concern in LQNG is hydrogen sulfide, if the H_2S is removed, the LQNG can be burned directly without violating any air pollution regulations. For new sources, this would generally require removing 90% of the sulfur from the feed. There would also be a limit on NO_x emissions, probably to 0.7 $lb/10^6$ Btu, which could require use of some low NO_x burner technology. No problems are anticipated in meeting either of these regulations, so burning LQNG in a dedicated facility, rather than upgrading it to pipeline quality, appears to be a very viable option. Most likely this would be done in a combined cycle plant, because gas turbines are capable of burning gases of quite low heating value, such as are produced by gasification of coal with air. Furthermore, techniques have been developed to limit NO_x emissions from combustion turbines.

3.2.2 Utilization as a Feedstock

Several possibilities exist here. As mentioned above, carbon dioxide is being used in secondary recovery operations. If the CO_2 content is large enough and the market is close enough, the LQNG could be processed for CO_2 recovery. The rejected methane could be burned to provide the energy for the CO_2 recovery operation.

Another possibility is the use of nitrogen containing LQNG as feedstock for ammonia production. In ammonia production after producing hydrogen by steam reforming of methane, air is added, and part of the hydrogen is burned to eliminate oxygen and leave a hydrogen-nitrogen mixture of the correct stoichiometry. If the correct amount of nitrogen is already present in the natural gas, this step would not be necessary. The reactions involved are:

$$CH_4 + 2H_2O \text{ ----> } 4H_2 + CO_2$$

$$3H_2 + N_2 \text{ ----> } 2NH_3$$

Combining these reactions gives an overall reaction of:

$$3CH_4 + 6H_2O + 4N_2 \text{ ----> } 8NH_3 + 3CO_2$$

Thus, if the LQNG contained 1.33 moles of nitrogen for every mole of methane converted to hydrogen, the stoichiometry would be correct. The economics would have to be looked at to see if the cost of the increased quantity of gas going to the reformer outweighed the savings from eliminating air addition, but there would appear to be some potential for LQNG of the correct nitrogen content as ammonia plant feedstock.

Utilization of LQNG as a feedstock for production of some chemical is not anticipated to result in any emission problems not already being addressed.

3.2.3 Upgrading to Pipeline Quality

As indicated above, all the contaminants in LQNG, with the exception of hydrogen sulfide, can be exhausted to the atmosphere once they are removed; and the H_2S is easily converted to elemental sulfur or sulfuric acid. Therefore, it is not anticipated than any air pollution regulations will be violated in upgrading LQNG to pipeline quality. Care will have to be exercised to prevent leaks and spills from processing units, such as amine units, from entering the environment, but these are standard processes for which control measures have already been developed, and no problems are anticipated.

3.3 Conclusions

The only contaminant in LQNG which is controlled under existing or anticipated regulations is H_2S, and well developed, commercially available process exist for removing H_2S and converting it to commercially salable by-products. Therefore, existing or anticipated air pollution regulations should present no barriers to utilization of LQNG.

4.0 EXISTING NATURAL GAS PROCESSING SCHEMES

As stated previously, the major contaminants in natural gas are hydrogen sulfide, carbon dioxide, nitrogen, water, and helium. In addition, many natural gas streams contain hydrocarbons heavier than methane. These contaminants are the same whether or not the natural gas stream is classified as low quality. That is, the difference between high quality natural gas and low quality natural gas is quantitative and not qualitative. This means that the processes used to prepare high quality natural gas for injection into natural gas transmission pipelines can also be used to upgrade LQNG. Therefore, it is instructive to look at the processes in common use to treat natural gas. These processes fall into the following categories:

1. Dehydration
2. Acid gas removal
3. Natural gas liquids recovery
4. Inerts (nitrogen and helium) removal

Inerts removal is only practiced currently in special cases, such as when there is a market for the produced nitrogen and/or helium or the inerts can be removed in conjunction with other processing, such as the recover of NGL's.

Natural gas as it comes from the well head is rarely suitable for immediate injection into gas transmission lines. Therefore, essentially all natural gas is processed at least to some degree before it is used. This section will review some typical processing flow schemes. Since Section 4.2 reviews typical processes currently in use for treating natural gas, the processes themselves will not be discussed but rather the combination of processes used to treat various types of natural gas.

4.1 Processing Schemes

4.1.1 Sweet, High Quality Natural Gas

The simplest situation involves gas which is sweet, i.e., free of hydrogen sulfide, of a high enough heating value (approximately 1000 Btu/SCF) that it meets pipeline specifications, and is predominantly methane. Such a gas is essentially ready for sale, except for moisture content. Virtually all natural gas streams, as produced, will be saturated with water. To prevent condensation of moisture in the transmission lines, distribution system, and fuel burning equipment, it is necessary to dry the natural gas. The moisture content of the gas will depend upon the temperature and pressure in the gas well, and the dehydration process chosen will depend upon the moisture content and the quantity of gas.

Figure 4-1 represents a block flow diagram for this simple case. The dehydrating agent is regenerated by raising its temperature and driving off the absorbed water as water vapor which is exhausted to the atmosphere. The target dew point of the treated natural gas will depend upon the transmission line specification, which may vary slightly depending upon location. Since the only by-product is water vapor, there are essentially no environmental problems. Spent desiccant may have to be occasionally disposed of, but the materials commonly used (glycols, silica gel) are not of major environmental concern, and their disposal should present no problem.

The only other possible requirement is compression, if the gas is at a lower pressure than the pipeline.

4.1.2 Sour, High Quality Natural Gas

This case represents the next level of complexity. The gas composition is the same as described in the previous section,

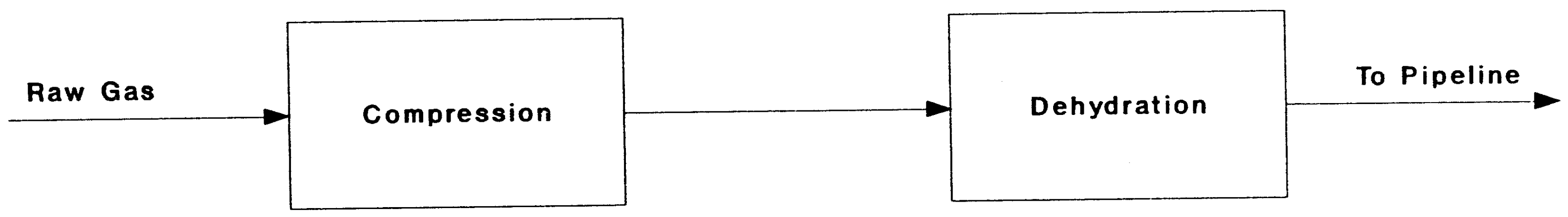


Figure 4-1. Treatment of Sweet Natural Gas

except that the gas contains some hydrogen sulfide. This means that a desulfurization process must be added to the processing scheme. This is illustrated in the block flow diagram shown in Figure 4-2. Because most desulfurization processes will add moisture to the gas, desulfurization is usually carried out upstream of dehydration.

Most commonly, desulfurization is accomplished by contacting the natural gas in a countercurrent absorber, where the hydrogen sulfide is absorbed into some type of solution. The rich solution is then transferred to a regeneration column, where it is heated to drive off the hydrogen sulfide. The recovered hydrogen sulfide is then converted to a final product, such as elemental sulfur or sulfuric acid. Elemental sulfur is a highly desirable product, since a large market exists for this product, and it is easily stored. The Claus process is usually used to convert the hydrogen sulfide to elemental sulfur. Depending upon local air pollution requirements and the efficiency of the Claus plant, a cleanup process may be needed to recover the sulfur in the Claus plant effluent.

Because of the efficiency of current sulfur removal processes, it is possible to meet stringent sulfur emission levels. It may from time to time be necessary to dispose of waste solutions from the absorber. In general, these will probably have to be treated as hazardous wastes, but the quantity of this material should be relatively small.

4.1.3 Sour Natural Gas Containing Carbon Dioxide

The next level of complexity beyond the previous case arises when the natural gas contains carbon dioxide in addition to hydrogen sulfide. However, carbon dioxide resembles hydrogen sulfide in that they are both weak acids. Therefore, materials that absorb hydrogen sulfide also in general absorb carbon dioxide. This means

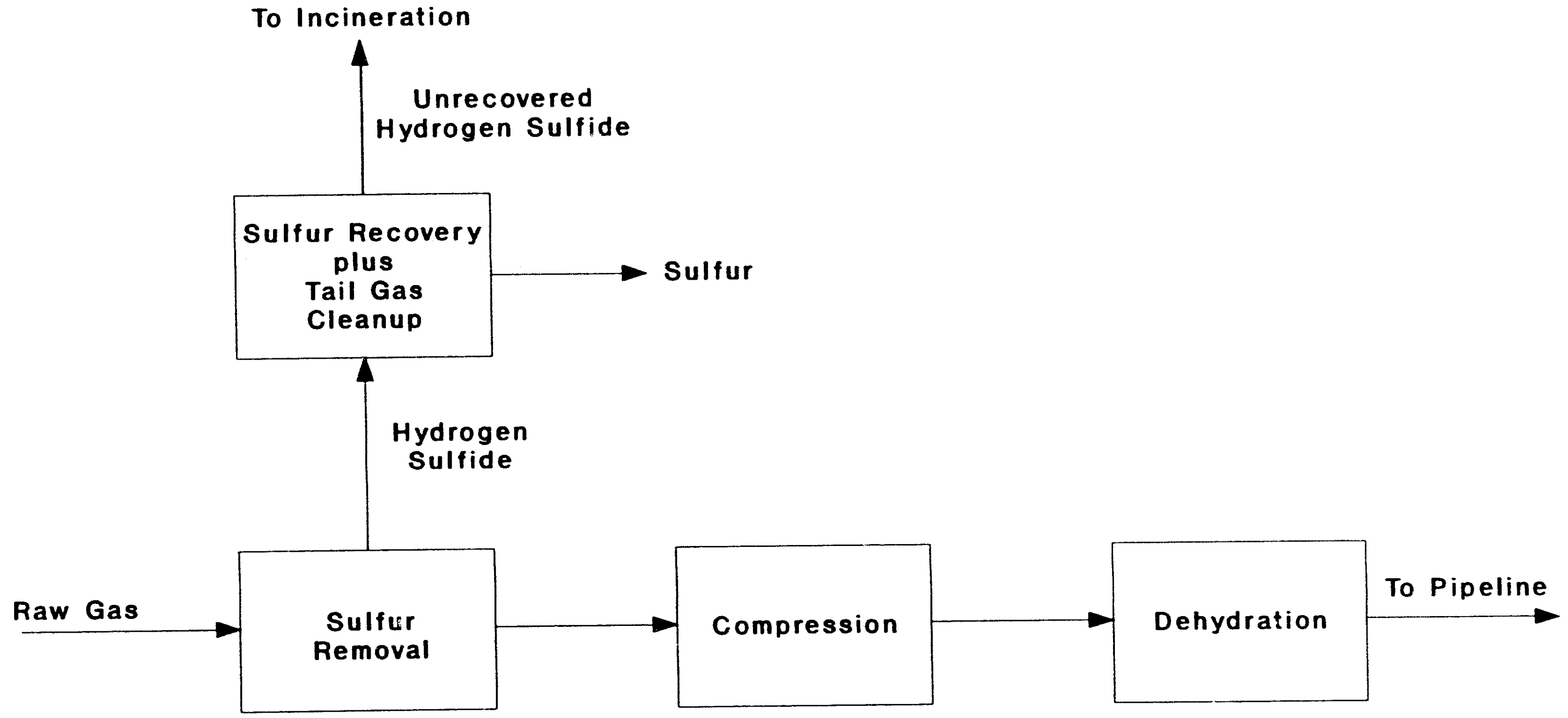


Figure 4-2. Treatment of High Quality Sour Gas

that the same process can be used to remove both hydrogen sulfide and carbon dioxide. Thus, it is not necessary to add another processing step to the processing sequence but rather merely to make the unit large enough to handle the load for both impurities. This scheme is illustrated in the block flow diagram in Figure 4-3.

In most cases, there will be no reason to separate the carbon dioxide from the hydrogen sulfide, and the combined stream from the stripping column will be sent to the Claus unit for recovery of sulfur. After sulfur removal, the carbon dioxide will be exhausted to the atmosphere.

Environmental concerns are the same as in the previous case.

4.1.4 Gas Containing Heavier Hydrocarbons

If the natural gas stream contains appreciable quantities of heavier hydrocarbons (ethane, propane, butanes, etc.), these will normally be removed, because they tend to be more valuable than methane. Furthermore, since heavier hydrocarbons have a much higher heating value on a volumetric basis, leaving these compounds in the natural gas would represent a giving away of product quality.

The heavier hydrocarbons removed have a variety of uses. Ethane is used mainly in the production of ethylene. Propane can be sent to cracking for the manufacture of ethylene and propylene or sold as propane LPG. Normal butane can be used in gasoline blending for vapor pressure control or sold as butane LPG. Isobutane is used as alkylation feed. C_5+ is usually sent to a refinery for use in the production of a wide range of products.

Figure 4-4 presents a block flow diagram for this case. The gas first goes to a knockout drum for removal of any entrained liquids. Then, after acid gas removal and dehydration, the gas goes to

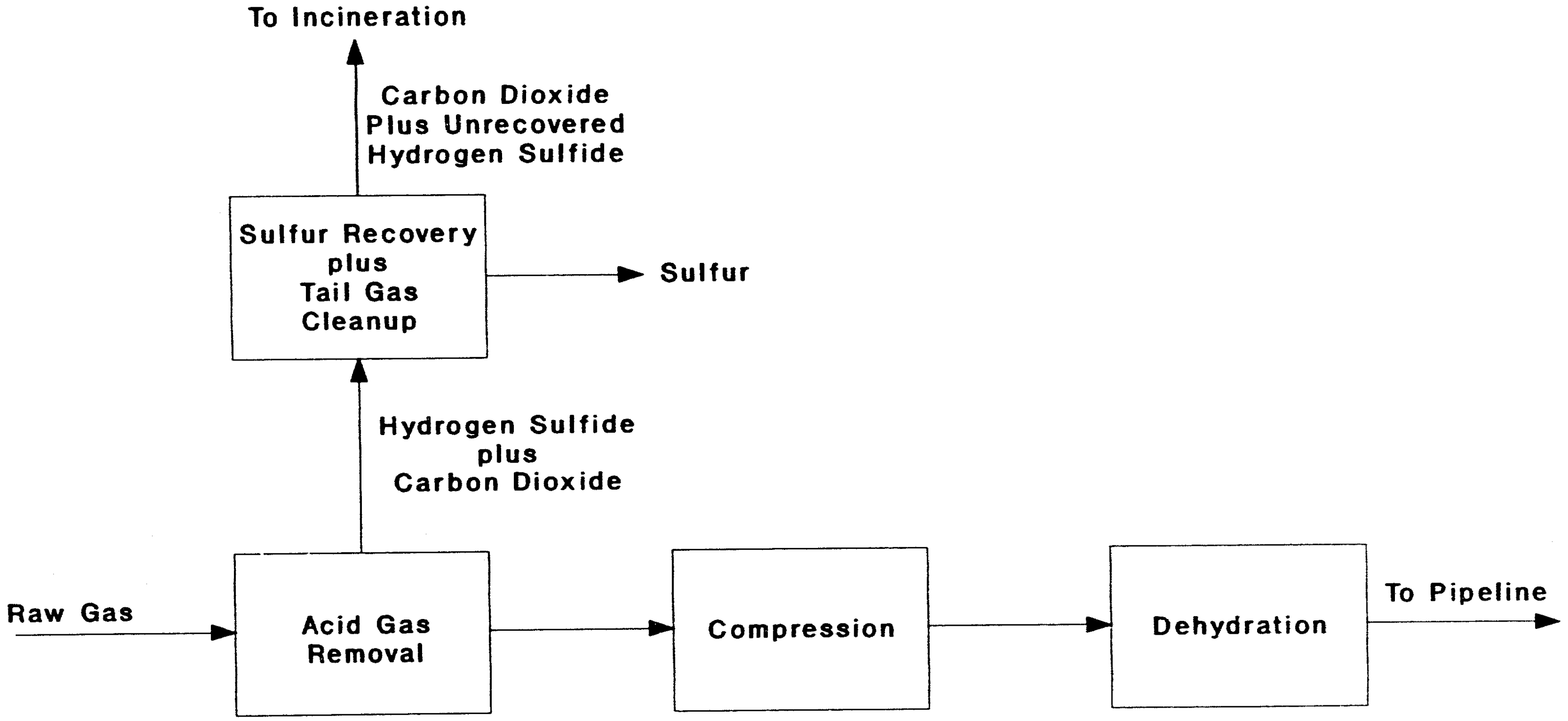


Figure 4-3. Treatment of Sour Gas Containing Carbon Dioxide

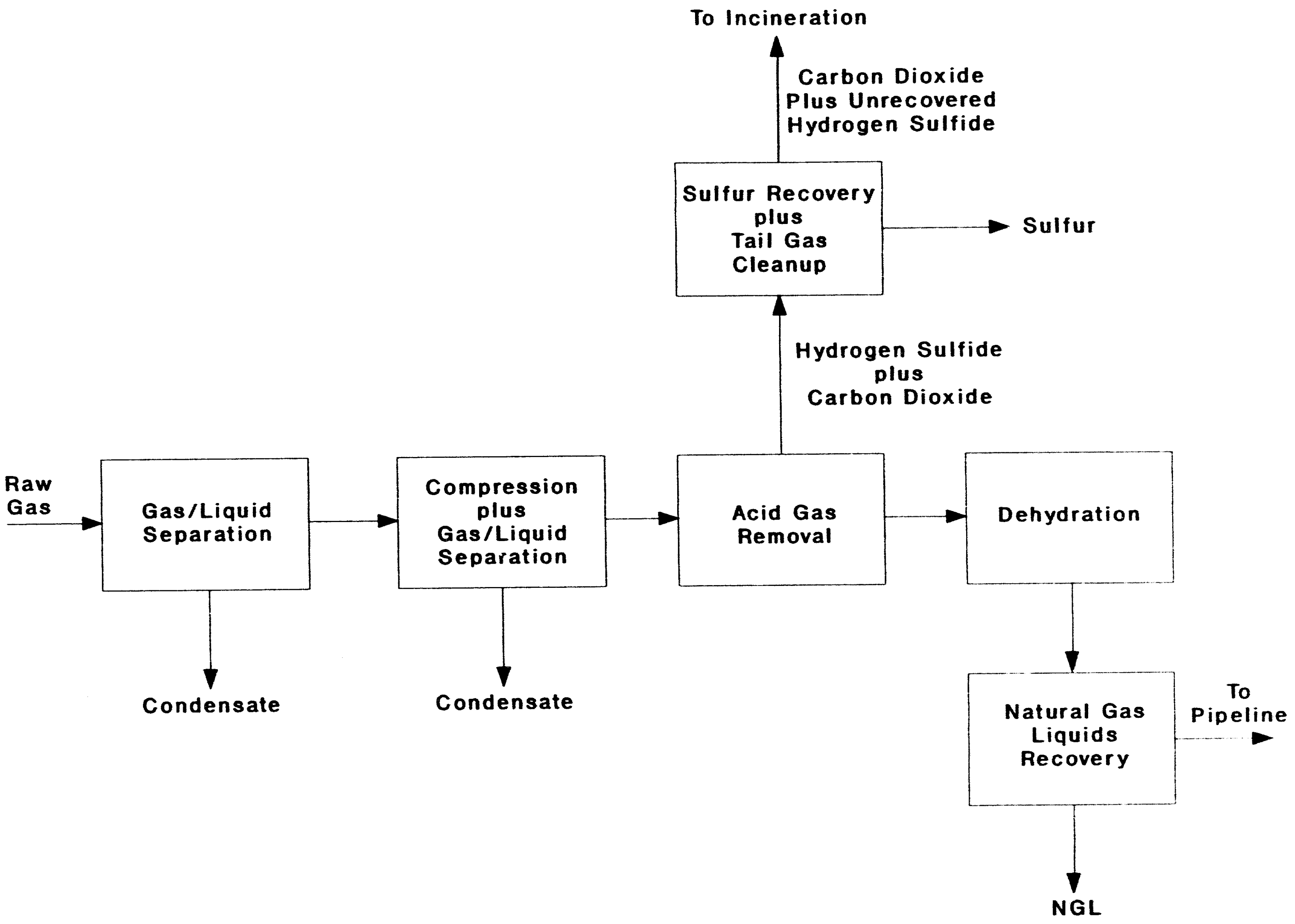


Figure 4-4. Treatment of Sour Gas Containing Heavy Hydrocarbons

hydrocarbon recovery. The two most common approaches for accomplishing this are absorption and cryogenic processing.

In absorption, the natural gas is contacted countercurrently in an absorber with a hydrocarbon stream of sufficiently low volatility, such as a naphtha. The heavier hydrocarbons dissolve in this oil at a low temperature. The rich oil is then sent to a regenerator where it is heated to drive off the light hydrocarbons, which appear as the overhead product.

In cryogenic processing, the natural gas is cooled sufficiently to condense the hydrocarbons heavier than methane. The condensed liquids are then separated from the methane. Further fractionation may be used to separate the mixed hydrocarbons into individual hydrocarbon streams, such as ethane, propane, butanes, and naphtha. In some situations, a combination of cryogenics and absorption may be used.

4.1.5 Gas Containing Nitrogen

At the present time nitrogen is not normally removed from natural gas for the primary purpose of producing pipeline gas, although it may be recovered for reinjection or as an adjunct to cryogenic processing, i.e., if ethane is being recovered, it may be economic to reject nitrogen at the same time. Pressure swing adsorption for the removal of nitrogen has also been developed. Although, as stated above, nitrogen removal is rare, there are a few examples. Figure 4-5 shows a block flow diagram for one such situation.

4.2 Upgrading Processes

This section discusses some of the most commonly used processes for upgrading natural gas. The processing areas which are discussed are dehydration, acid gas removal, and hydrocarbon recovery.

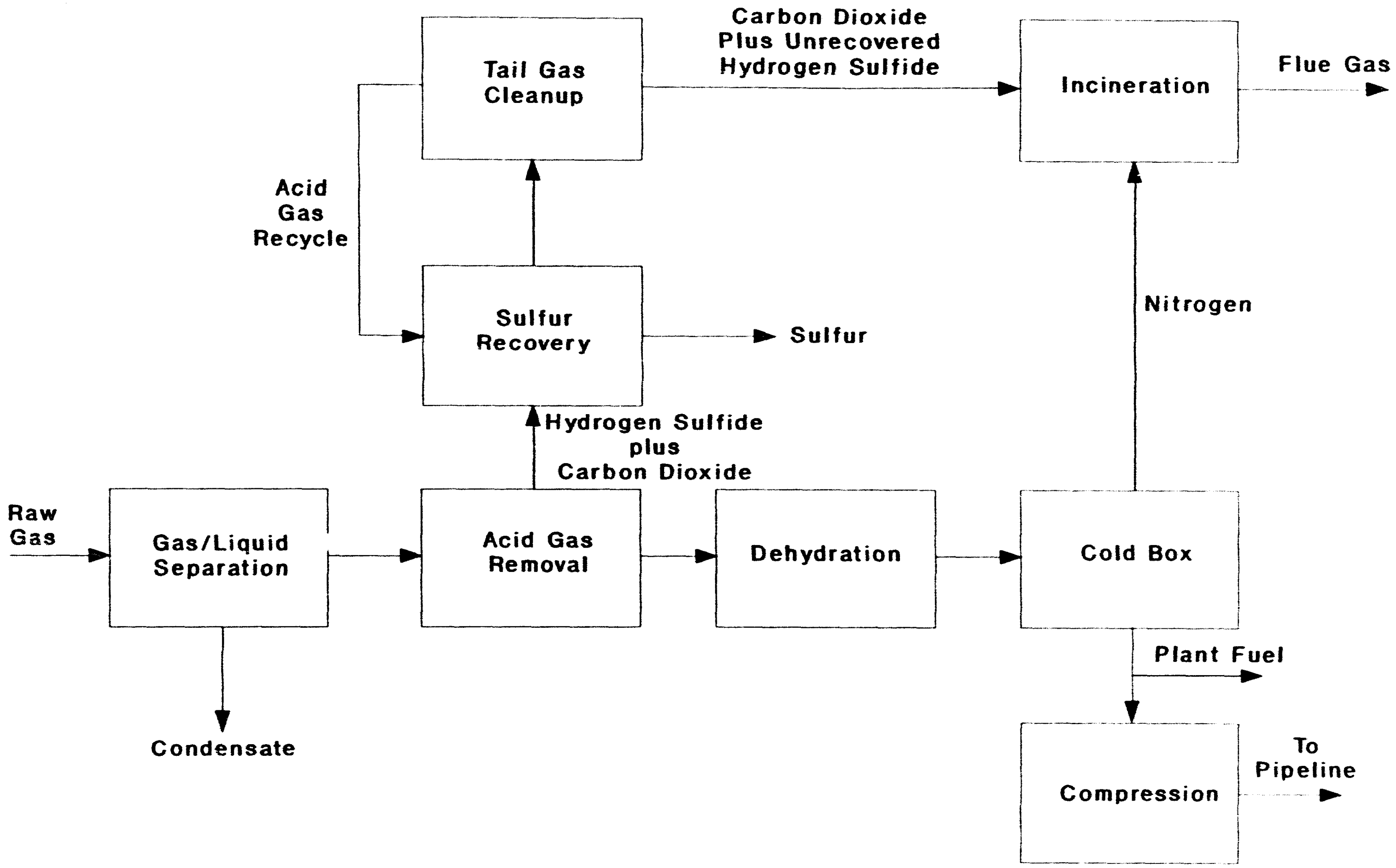


Figure 4-5. Processing of Sour Gas Containing Nitrogen

4.2.1 Acid Gas Removal Processes

Acid gas removal processes can conveniently be divided into the following four categories:

1. Carbonate based processes
2. Amine based processes
3. Physical solvent based processes
4. Other

Each of these categories will be discussed separately.

4.2.1.1 Carbonate Based Processes

In carbonate based processes, the natural gas is contacted by a solution of potassium carbonate (K_2CO_3) in water. The major reactions that occur are:

$$K_2CO_3 + H_2S \text{ ----> } KHCO_3 + KHS$$

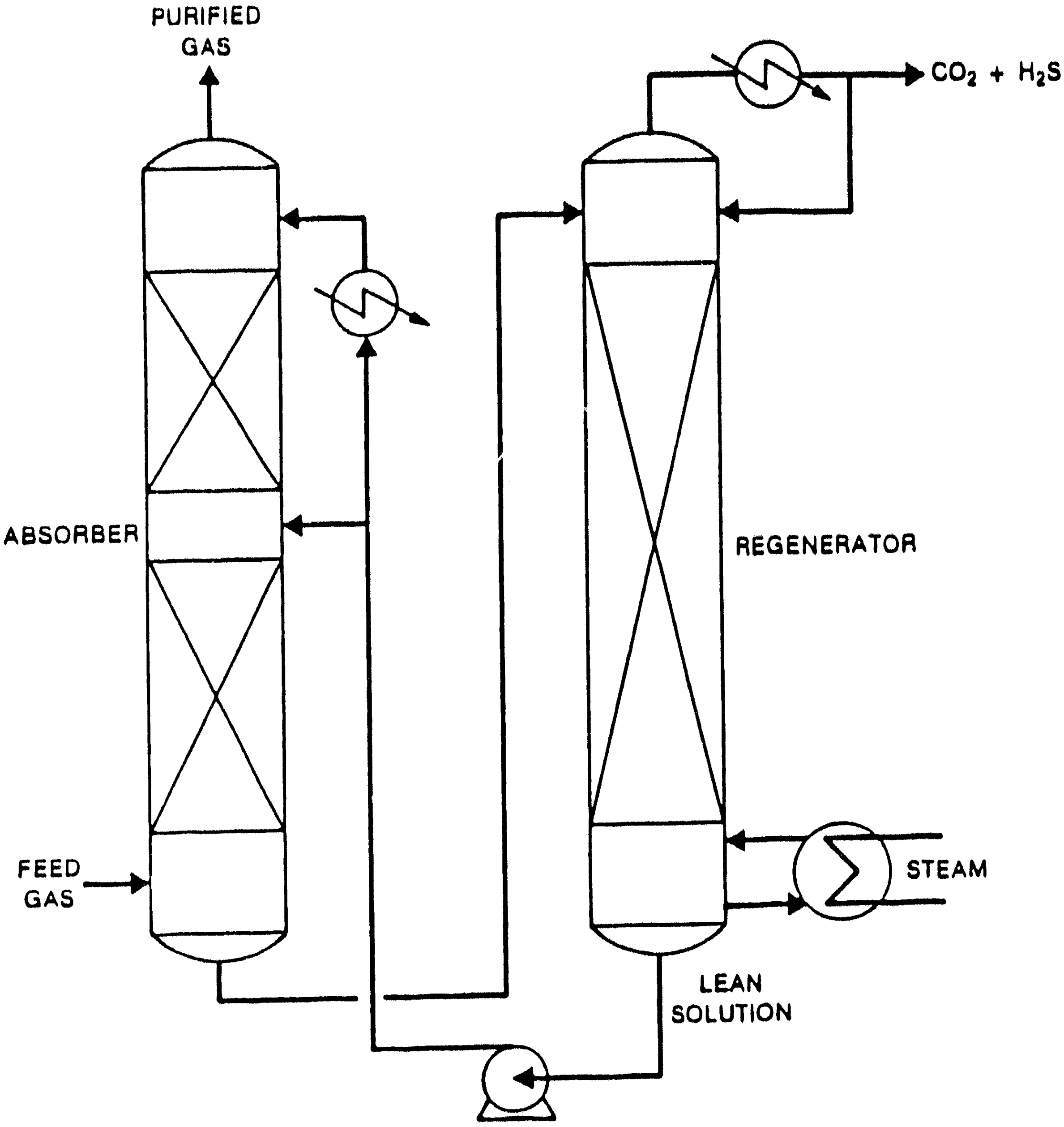
$$KHCO_3 + H_2S \text{ ----> } K_2S + CO_2 + H_2O$$

$$K_2CO_3 + CO_2 + H_2O \text{ -----> } 2KHCO_3$$

Upon heating, these reactions are reversed, and the absorbed hydrogen sulfide and carbon dioxide are released with the regeneration of the potassium carbonate, which is cooled and recycled to the absorber.

Figure 4-6 is a schematic flow diagram of the Benfield process, which is typical of potassium based processes. As can be seen, the process is basically quite simple, consisting essentially of only an absorber column and a regeneration column. If the natural gas is available at high pressure, then the absorption can take place at elevated temperature and the potassium carbonate solution can be regenerated by lowering the pressure with little need for the

Figure 4-6



BENFIELD PROCESS WITH SPLIT FLOW ABSORBER addition of heat. Also, the need for a heat exchanger between the absorber and regenerator is eliminated. Various minor variations of the process are possible, depending on the composition of the feed gas and desired purity of the product gas.

Corrosion is a potential problem, and for plants where only carbon dioxide is being removed, potassium dichromate is added as a corrosion inhibitor. Corrosion is less of a problem when some hydrogen sulfide is present, as the hydrogen sulfide appears to act as a corrosion inhibitor. Stainless steel is used in critical parts of the plant.

4.2.1.2 Amine Based Processes

Solutions of various amines, such as monoethanolamine (MEA) and diethanolamine (DEA), are used as solvents for the absorption of hydrogen sulfide and carbon dioxide from natural gas. The chemistry involved is:

$$RNH_2 + H_2S \text{ ----> } RNH_3SH$$

$$RNH_3SH + RNH_2 \text{ ----> } (RNH_3)_2S$$

$$RNH_2 + CO_2 + H_2O \text{ ----> } RNH_3CO_3H$$

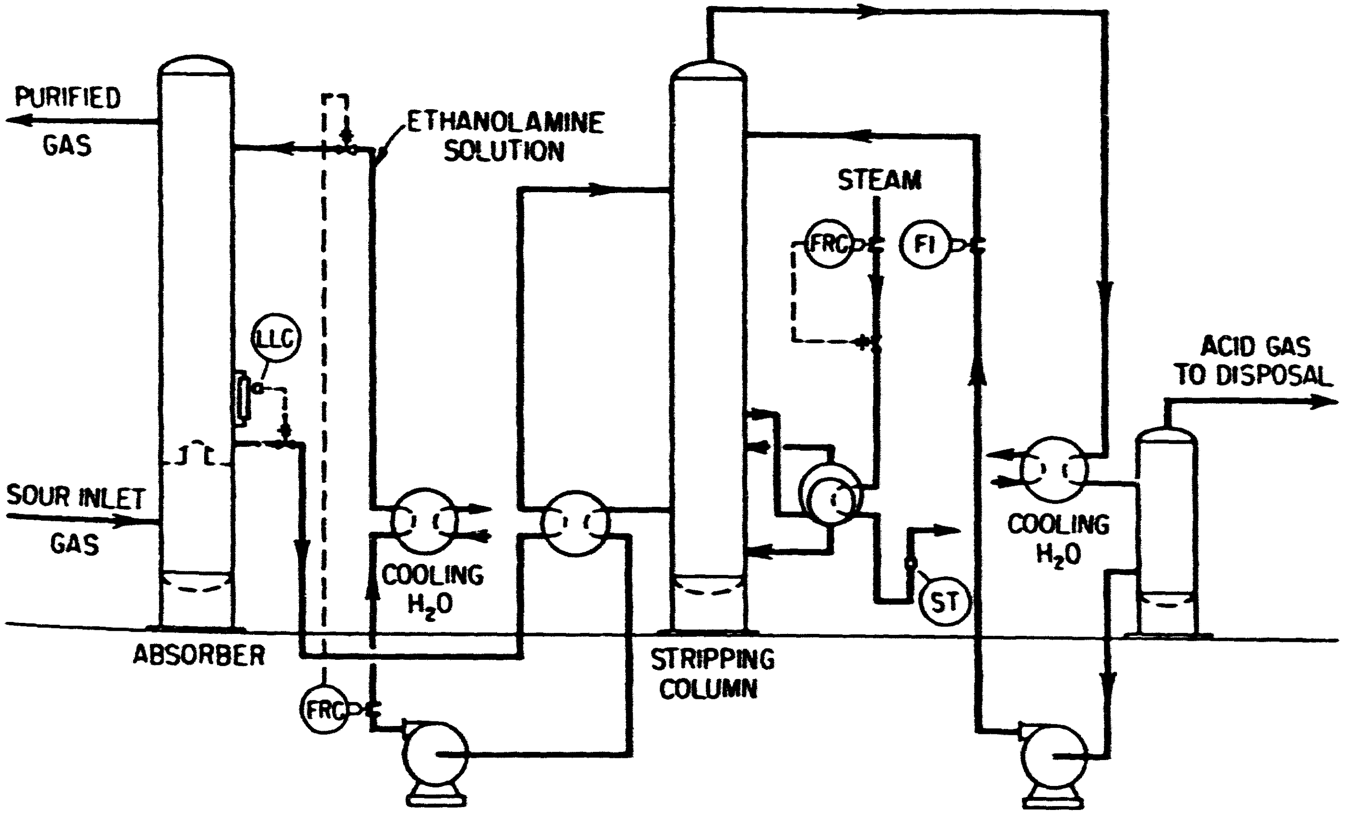
$$RNH_3CO_3H + RNH_2 \text{ ----> } (RNH_3)_2CO_3$$

$$2RNH_2 + CO_2 \text{ ----> } RNHCOONH_3R$$

where R represents a hydrocarbon radical. The strength of the compounds formed by these reactions depends upon the particular amine being used, but in general they are rather weak; and upon heating they decompose to release the absorbed hydrogen sulfide and carbon dioxide and regenerate the amine.

Figure 4-7[15] is a schematic process flow diagram of a typical alkanolamine process. The choice of the amine and its concentra-

Figure 4-7



Basic flow scheme for alkanolamine acid-gas removal processes.

tion depends upon the temperature and pressure of the natural gas, its composition, and the desired purity of the treated gas.

The flow scheme is relatively simple. The natural gas to be purified flows countercurrent to the amine solution in the absorber, The rich amine solution is heated by heat exchange with the lean amine from the bottom of the stripper and sent to the top of the stripping column for removal of absorbed hydrogen sulfide and carbon dioxide. If conditions in the absorber are such that appreciable quantities of hydrocarbon are dissolved in the amine, the amine solution may be flashed to remove these hydrocarbons before being sent to the stripper. (Hydrocarbons in the stripper offgas can lead to discolored sulfur product.) The acid gas stream from the stripper is cooled to condense water vapor. This condensate is reintroduced into the system to prevent the amine solution from gradually becoming more concentrated. In some units the acid gas is water washed at the top of the column to recover amine.

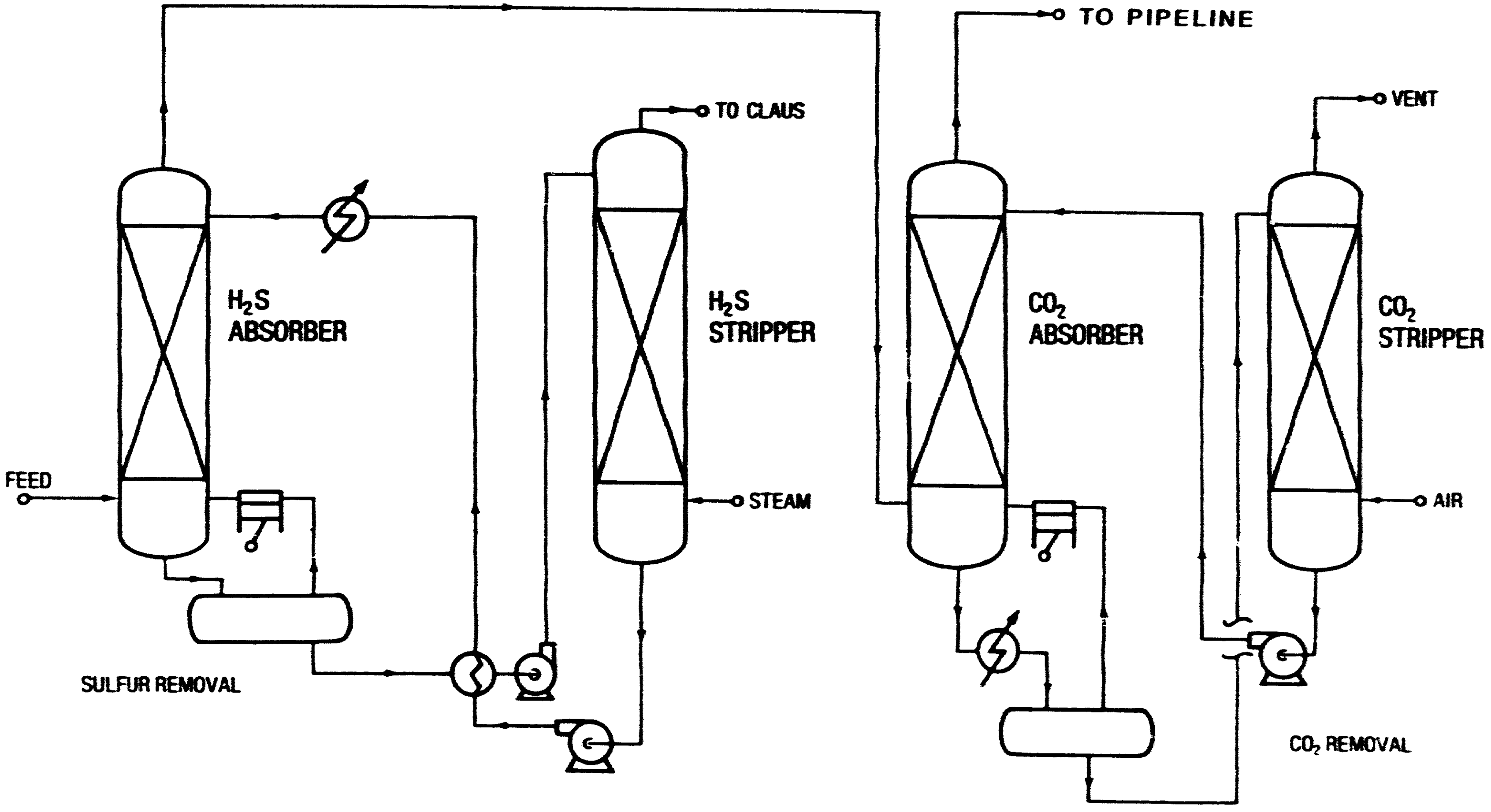
4.2.1.3 Physical Solvents

In processes involving physical solvents, the natural gas is contacted with a solvent in a countercurrent column, where the acid gases dissolve in the solvent. The rich solvent is then pumped to a stripping column where the temperature is raised to release the dissolved gases from the solvent. The lean solvent is then cooled and returned to the absorption column.

Figure 4-8[15] is a simplified flow diagram of the Selexol Process, which uses as a solvent the dimethyl ether of polyethylene glycol. Selexol is a typical physical solvent process.

Because hydrogen sulfide is about nine times as soluble in the Selexol solvent as is carbon dioxide, the Selexol process can be used for the selective removal of hydrogen sulfide. In addition

Figure 4-8



Flow diagram of SELEXOL Process for acid gas removal methylmercaptan and carbon disulfide are also quite soluble in the Selexol solvent. The Selexol solvent is reported to be stable to heat and oxidation and to be nonreactive with natural gas constituents. Its low vapor pressure means that solvent losses to the product gas are small.

4.2.1.4 Hybrid Processes

The Sulfinol Process, which uses a combination of amines and a physical solvent, is a hybrid of the two previous process types. The flow diagram show in Figure 4-9[15] is very similar to the flow diagrams discussed above. Because of the high solubility of hydrocarbons in the Sulfinol solvent, the rich solvent is flashed to remove hydrocarbons before regeneration. If desired, the flash gas can be compressed and recycled to the absorber or used as plant fuel.

4.2.1.5 Other Processes

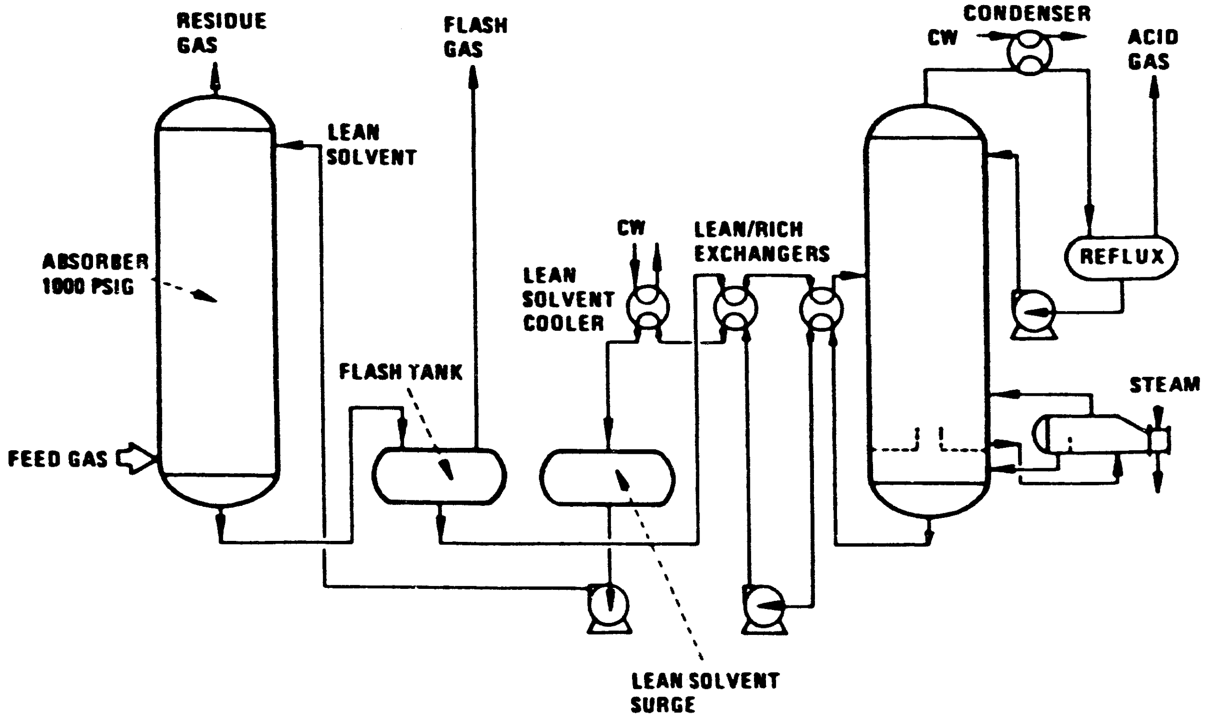
Although processes involving the use of liquid solutions represent the vast majority of the processes in use for acid gas removal from natural gas, some other processes are occasionally used. One such process is the iron oxide process. Ferric oxide reacts with hydrogen sulfide and can be used to desulfurize gas streams. This is one of the oldest gas desulfurization processes known, and the basic chemistry is represented by the following equations:

$$Fe_2O_3 + 3H_2S \text{ ----> } Fe_2S_3 + 3H_2O$$

$$2Fe_2S_3 + 3O_2 \text{ ----> } 2Fe_2O_3 + 6S$$

In processes utilizing this chemistry, the gas stream contaminated by hydrogen sulfide is passed through a bed of ferric oxide. After the oxide has been converted to the sulfide, the gas flow is switched to a fresh bed, the first bed is regenerated by passing

Figure 4-9



Typical flow diagram of Sulfinol process.

air through it, as shown in the schematic flow diagram in Figure 4-10[15].

The iron oxide process is not capable of removing carbon dioxide and is used predominantly for treating gas derived from coal gasification rather than natural gas. It is best suited to treating relatively small volumes of gas and is used only occasionally to treat natural gas streams.

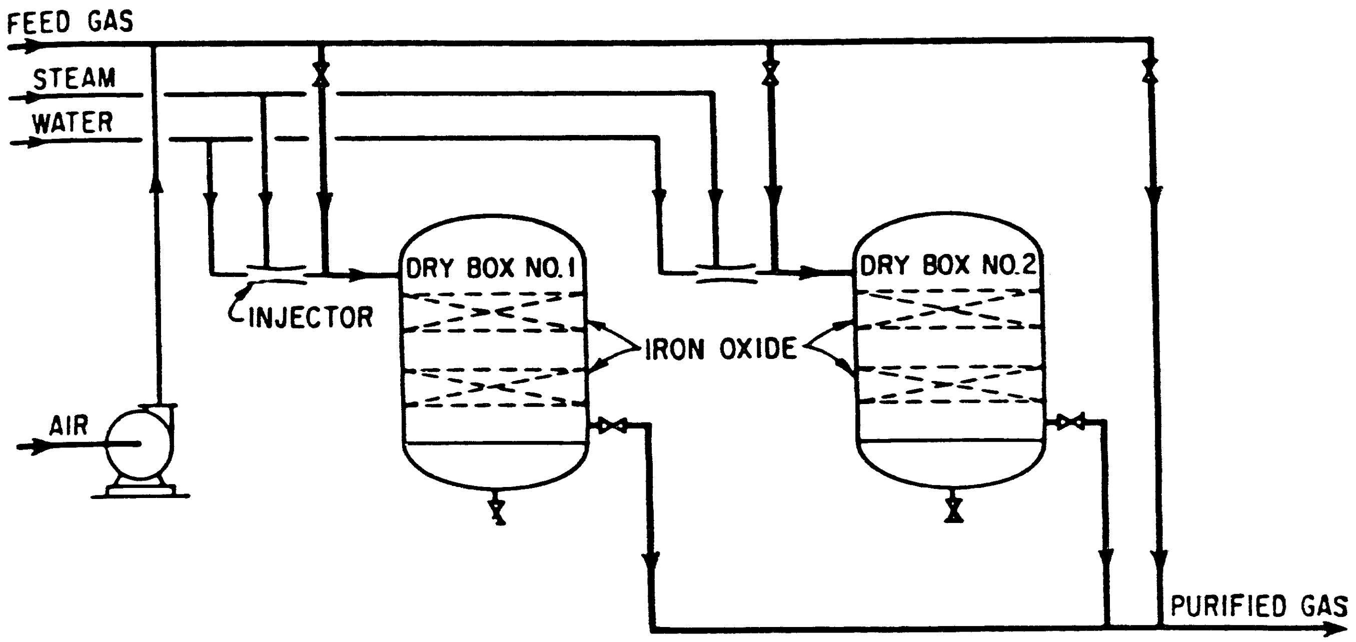
4.2.2 Dehydration

In order to avoid condensation of moisture in pipelines and combustion equipment, it is necessary to dry natural gas. In addition to the water present in the gas as produced, moisture can also be introduced from acid gas removal processes. Therefore, dehydration is required of virtually all natural gas streams. There are two basic types of dehydration processes: those based on solid desiccants and those based on liquid desiccants. These two process types are discussed below.

4.2.2.1 Solid Desiccants

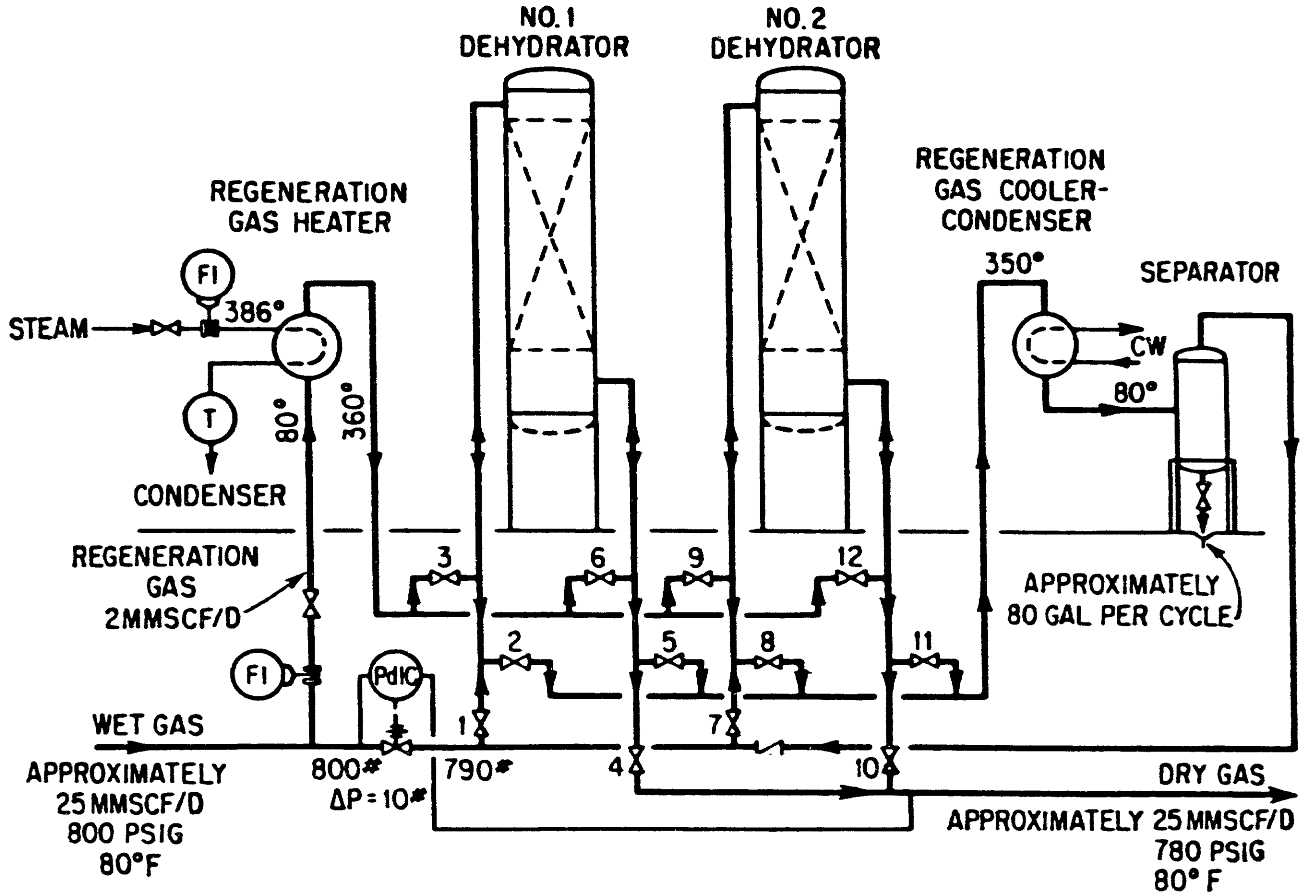
There are many solid materials which will adsorb moisture from natural gas. Those that are used most commonly are silica and alumina. In general, a unit for removing water from natural gas using a solid desiccant will consist of two vessels filled with granular solid desiccant, as shown in Figure 4-11[15]. One of these vessels will be on stream drying the gas, while the other vessel is being regenerated. This regeneration is accomplished by passing hot gas through the bed. When moisture breakthrough occurs in the first vessel and the second vessel has been regenerated, the flow pattern is reversed.

Figure 4-10



Schematic flow diagram of basic iron oxide purification process.

Figure 4-11



Process flow diagram of typical natural-gas dehydration plant.

4.2.2.2 Liquid Desiccants

Although there are many liquids which are capable of absorbing water from gases, those in most common use for drying natural gas are diethylene glycol (DEG) and triethylene glycol (TEG), although other glycols are sometimes used. A typical flow scheme for a glycol based dehydration process is show in Figure 4-12[15]. As can be seen, the process is very similar to acid gas removal using an amine solution.

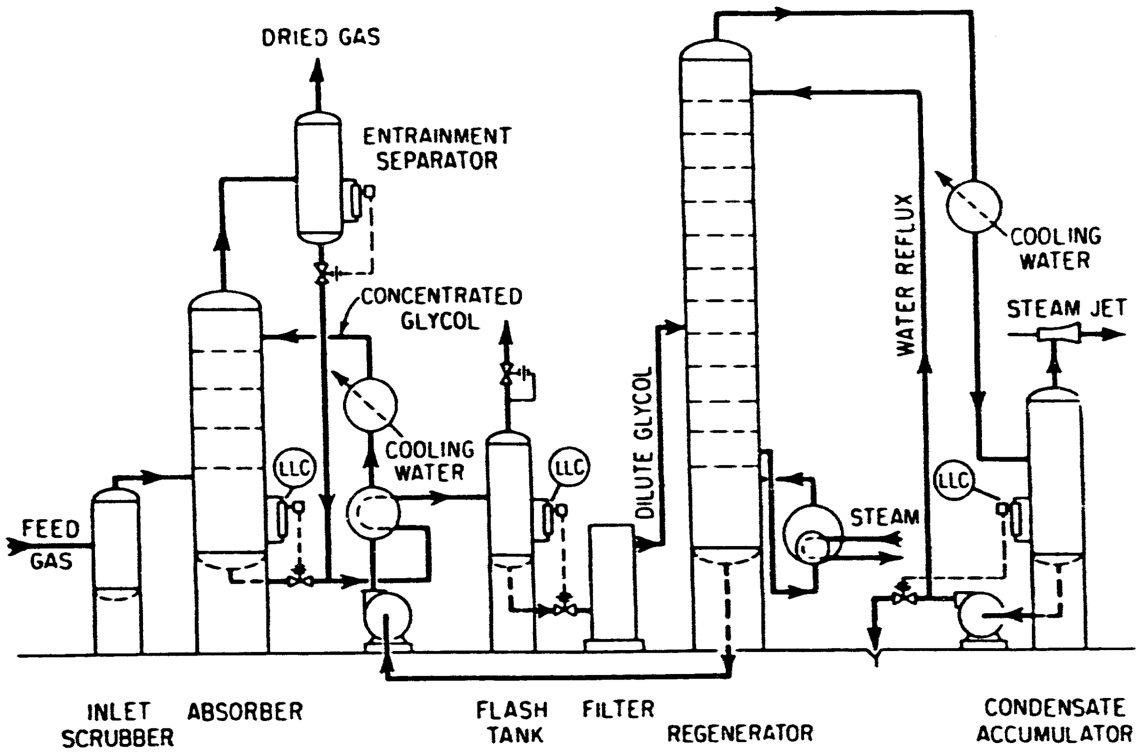
The natural gas is contacted with the glycol in a countercurrent absorber. The glycol from the bottom of the absorber is sent to a regenerator, where its temperature is raised to drive off the absorbed moisture. The regenerated glycol is then cooled by heat exchange with the wet glycol and sent to the top of the absorber.

4.2.2.3 Membranes

Although membranes have been developed for dehydrating gases, they are typically not used for natural gas drying. There are two reasons for this. The first is the very high selectivity of the glycol and solid desiccant processes. With glycol, the natural gas can be dried with very little loss of hydrocarbons. However, with a membrane some methane will diffuse through the membrane with the water.

The second reason membranes have not penetrated the natural gas dehydration market is that high water removal rates are needed. For example, to lower the dew point of natural gas from 50 °F to -40 °F requires removal of 99% of the water in the gas. Not only is this high a removal difficult to achieve with membranes, but the final partial pressure of water in the gas is so low as to provide almost no driving force for the membrane separation. Thus, multiple staging and large surface areas would be required, making

Figure 4-12



Flow diagram of typical glycol dehydration plant. Design shown would be employed where a large volume of high-pressure gas must be dehydrated to very low water-vapor levels.

membranes, at the current state of development, uneconomic for drying most natural gases.

4.2.3 Hydrocarbon Recovery

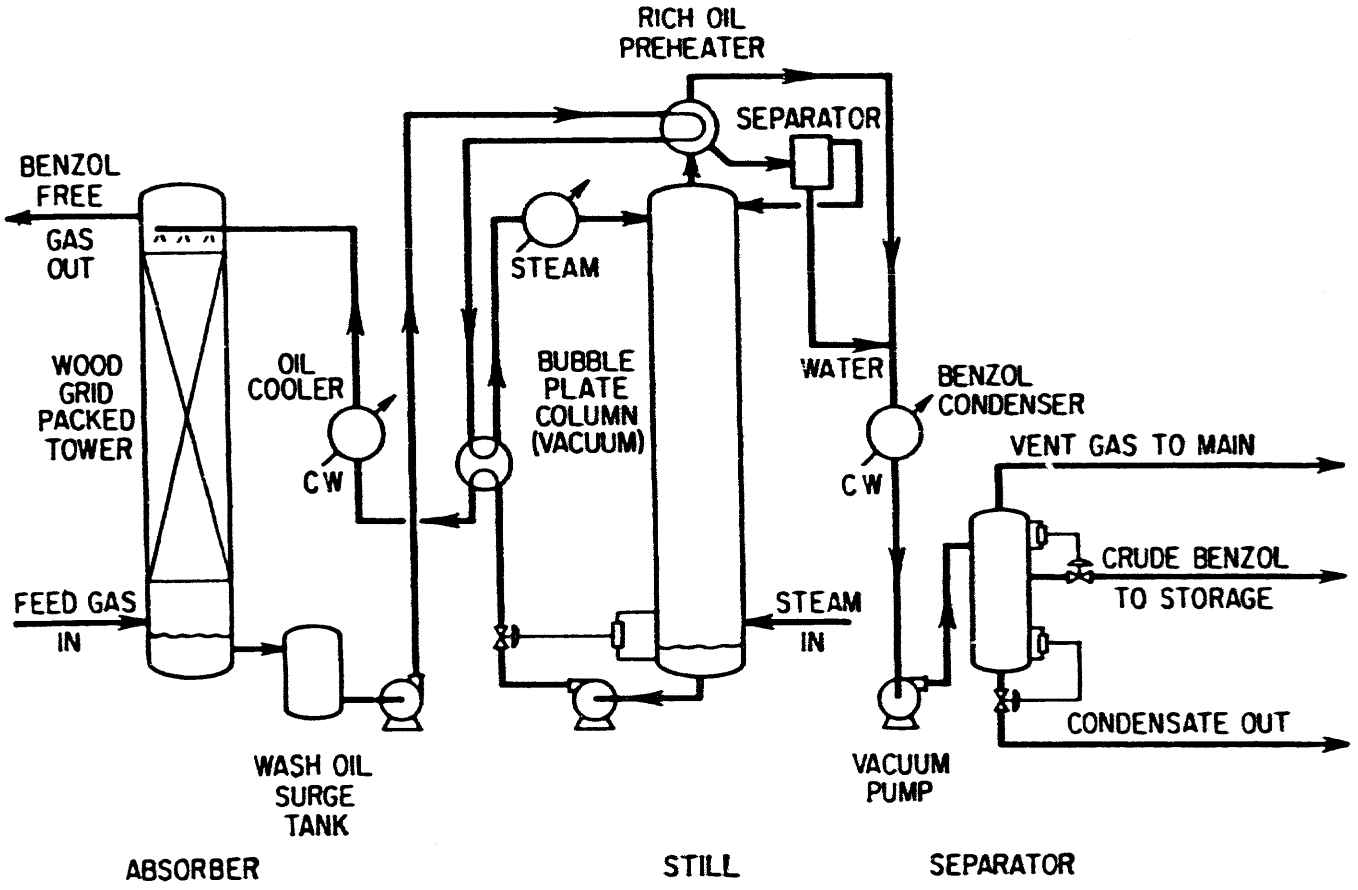
In addition to removing acid gases and water, it is frequently desirable to recover heavy hydrocarbons. This is usually accomplished by means of either absorption in a liquid stream or by use of a cryogenic system.

4.2.3.1 Recovery of Hydrocarbon Vapors by Oil Absorption

The adsorption of heavy hydrocarbons from natural gas streams by absorption in liquid oils is an important part of many natural gas processing schemes. In this operation no chemical reactions are involved, and the distribution of a given hydrocarbon between the liquid and solid phases depends only on vapor/liquid equilibrium considerations. Typically, the absorber oil used would have a low enough vapor pressure so that vaporization losses from the system are acceptable but be light enough so that its viscosity and other physical properties are suitable, for example a light gas oil.

Figure 4-13[15] presents a simplified flow diagram of a light-oil absorption plant. The hydrocarbon vapors are absorbed by countercurrent contact of the oil and natural gas in the absorber. The rich oil is then sent to a stripper where the oil is regenerated by steam stripping or fractionation. The lean oil is then cooled by heat exchange with the rich oil and pumped to the top of the absorber. The overhead from the stripping column is condensed, and the natural gas liquids are recovered. This approach is effective for recovering liquid hydrocarbons but is not very suitable if it is desired to recover a significant fraction of the ethane for ethylene manufacture.

Figure 4-13



Simplified flow diagram of light-oil absorption plant.

4.2.3.2 Hydrocarbon Recovery by Cryogenics

After acid gas removal and dehydration, the natural gas temperature is lowered sufficiently by means of refrigeration to condense essentially all the propane and heavier and the desired fraction of the ethane. After gas/liquid separation, the gas is sent to sales, and the liquid is sent to fractionation. In a series of fractionators, ethane, propane, butanes, and natural gasoline are recovered.

4.2.4 Nitrogen Removal

Because nitrogen is relatively inert and has the lowest boiling point (except for helium) of the constituents of natural gas, nitrogen removal is difficult and expensive. Under normal circumstances, the removal of nitrogen can rarely be justified. If the nitrogen level is higher than desired, then the gas stream may be blended off with a low nitrogen natural gas stream so that the combined stream meets the desired heating value. Alternatively, sufficient ethane may be left in the natural gas to reach the target heating value. If neither of these approaches is feasible, then the gas field would normally be shut in awaiting the time when the price of natural gas increased to the point where nitrogen removal was justified.

There may be a few special cases where nitrogen removal is practiced. One of these cases is with gas streams containing helium which is being recovered. In this case nitrogen removal may be practiced as an adjunct to helium recovery. However, since the strategic stockpile is currently full, helium recovery is less important than it was some years back. A second situation that may justify nitrogen removal is if it is desired to use the recovered nitrogen for field pressure maintenance or enhanced recovery operations. Currently, two major technologies are available for nitrogen removal: cryogenics and pressure swing adsorption.

4.2.4.1 Cryogenic Separation of Nitrogen

Cryogenic separation of nitrogen consists basically of liquefying the natural gas and separating the nitrogen from the methane by fractionation. This is basically the same technology that is used in air separation plants, except that there the separation is between nitrogen and oxygen rather than nitrogen and methane. Cryogenic separation is relatively expensive and is only justified where the recovered nitrogen has a sufficiently high value.

4.2.4.2 Nitrogen Removal by Pressure Swing Adsorption

In pressure swing adsorption (PSA), material is adsorbed on a bed of solid adsorbent and then desorbed at a lower pressure with no change in temperature except that caused by the heats of adsorption and desorption. The lack of a requirement for heat leads to a simple installation compared to a system requiring thermal regeneration, but this advantage is offset by greater losses from venting and low-pressure purging. Furthermore, since both methane and nitrogen are nonpolar and nitrogen is lower boiling than methane, then in the separation of nitrogen from methane using PSA, the methane is the material that is adsorbed. Thus, removing small amounts of nitrogen from methane using PSA would not appear to be attractive.

5.0 COST OF UPGRADING LQNG TO PIPELINE QUALITY

In order to ascertain the potential for commercialization, capital costs and gas processing costs for several upgrading processes have been developed. Typical possible applications have been selected from the literature and modified to bring them to a common basis so that the relative attractiveness of the applications may be compared. After review of the nature of the gas reserves, a scenario was selected to serve as a realistic basis for comparison.

5.1 Design Basis for Calculations

To facilitate comparisons among cases, a common design basis was used for all cases. The rational for the basis chosen is discussed below.

5.1.1 Raw Feed Gas

The feed gas is a typical wellhead gas from a single well or gathering system. Gas is normally available at high pressures. Many studies and reports are based on pressures in the range of 800 to 1000 psig; 800 psig was selected for this study. A 80 ^{o}F temperature was assumed.

In order to take full advantage of economies of scale, a high gas flow rate is indicated. However, economy of scale tends to disappear when the maximum possible capacity of a single processing train is reached. A review of available literature showed that the largest reported commercial gas upgrading facility[16] had a single train capacity of about 70 to 80 x 10^6 SCFD of methane or about 100 x 10^6 SCFD of raw gas. For the cryogenic nitrogen rejection unit, the methane flow was limiting, and additional raw gas could have been handled. Therefore, a base methane flow near 80 x 10^6 SCFD was selected as a probable maximum single train capacity.

This flow was used for all processes studied even though some, such as adsorbent and membrane systems, require parallel trains or units at much lower capacities.

Although the focus of this study is on nitrogen and carbon dioxide contaminants, it must be recognized that most gas collected for treatment contains H_2S and water. It is reported that 80% of gas being fed to treatment plants in use today contains less than 1% sulfur (Table 1-3). For this study a value of 0.6% H_2S was selected as typical, but a high sulfur case (2.7% H_2S) was selected for comparison. Feed gas is assumed to be saturated with water at 80°F.

As shown in Figure 1-4, few reserves contain more than 20% nitrogen. Values of 6 and 13% were selected as including about 96% of total reserves, and a high nitrogen case (26% N_2) was selected for comparison.

Similarly, it is seen from Figure 1-5 that 96% of total reserves contain less than 10% carbon dioxide. Values of 4 and 7% were selected as accounting for most of the treatable reserves containing only carbon dioxide as an impurity. A 15% CO_2 case was selected for comparison. It is recognized that enhanced oil recovery (EOR) operations plus a few fields produce gas with very high carbon dioxide contents, but these are not considered to be pertinent to the goals of this study.

In summary, the raw feed gas compositions used in the economic evaluations are as shown in Table 5-1.

Table 5-1

RAW FEED GAS COMPOSITIONS

Component	Content, vol%
Hydrogen Sulfide	0.6, 2.7
Water	Saturated at 80°F
Carbon Dioxide	4, 7, 15
Nitrogen	6, 13, 25
Ethane and Heavier	Negligible
Methane	Balance of Feed

5.1.2 Product Gas

The product gas is assumed to be added to an existing pipeline and needs to be at an elevated pressure. Most upgrading processes operate with a low pressure drop (10 to 15 psi). A product gas pressure of 785 psig was selected.

Product gas composition (see Table 5-2) is selected to meet pipeline quality, as discussed in Section 1.3.

Table 5-2

PIPELINE QUALITY CRITERIA

Component	Content
Nitrogen	4% max.
Carbon Dioxide	2% max.*
N_2 plus CO_2	4% max.
Hydrogen Sulfide	0.25 grain/100 SCF max. (approx. 4 ppmv)
Water	7 lb/10^6 SCF*

---

* May be substantially less because of process pretreatment requirements.

5.1.3 Plant Design Limitations

Since upgrading plants will tend to be located in remote areas, they should be self sufficient in energy. Therefore, no purchased electric power, steam, or fuels were used in any of the cases evaluated for this study.

Similarly, the plants should not depend upon credits for energy exports and/or by-products for commercial viability. Therefore, although facilities for shipment of sulfur are provided, no credit for sulfur is taken, nor are sulfur disposal costs included in the economics.

5.2 Upgrading Processes Selection

5.2.1 Pretreatment (Sulfur and Water Removal)

From the processes described in Section 4.2, fully commercialized processes were selected for desulfurization, sulfur recovery, and dehydration. These are:

Desulfurization - Selexol, diethanolamine (DEA)
Sulfur Recovery - Claus
Tail Gas Treatment - SCOT
Dehydration - Glycol (TEG)

These processes were selected because they operate satisfactorily at the design basis chosen, and they are already considered to be economical for a wide range of applications.

5.2.2 Nitrogen Removal

One established process, cryogenic nitrogen rejection, was selected as a bench mark; and a developing process, carbon molecular sieves, was evaluated to establish its economic potential. Several other processes, such as one based on hydrate formation, were considered but not selected for full evaluation because of a lack of satisfactory cost information.

5.2.3 Carbon Dioxide Removal

As in the case of nitrogen removal, two processes were selected for evaluation. One process is the proven amine system (DEA), which has a very large number of commercial installations. The other carbon dioxide removal process selected is membrane separation, which is newer and less extensively used. Although the membrane process has been installed for commercial applications, it is still being improved and has not reached its full potential.

Cryogenic approaches, such as Ryan-Holmes[17], have been developed primarily for very high CO_2 content and do not appear to be competitive in the range of interest. Molecular sieves are competitive in a narrow range of application, such as cleanup of trace quantities[18], but have not been installed for bulk removal in recent years.

Since hydrogen sulfide is normally present, it is logical to remove H_2S and CO_2 together, when a solvent system is used for carbon dioxide removal. The amine (DEA) system chosen for this study is suitable for the removal of H_2S plus CO_2 or CO_2 alone.

5.2.4 Combined Nitrogen and Carbon Dioxide Removal

When both carbon dioxide and nitrogen need to be reduced, no single process has yet been shown to be effective. Consequently, two processes are required. For this study a cryogenic system was selected for nitrogen removal and an amine system for carbon dioxide removal.

5.3 Reference Data

5.3.1 Feed Gas and Operating Pressures

The various reference studies were based on feed gas pressures generally in the range of 800 to 1000 psig. Cryogenic nitrogen rejection units (NRU) operate at 350-400 psig, and the carbon molecular sieve bases pressure swing adsorption (PSA) process loses separation selectivity above 200-250 psig, requiring feed gas pressure reduction.

5.3.2 Product Gas Pressure

Most studies show methane-rich product gas going to a pipeline at or near feed gas pressure, but some of the studies utilizing low pressure separation show product gas being boosted to only 300 or 500 psig, requiring supplemental compression.

5.3.3 Feed Gas Capacity

The reference studies were based on a very wide range of feed gas capacities, from a small hypothetical plant of 1×10^6 SCFD capacity to an installed plant capable of processing 300×10^6 SCFD. Scaling reference flows to the base capacity of this study in most cases required a change by no more than a factor of four. Lack of data at higher flow rates necessitated a large scale-up for only the PSA nitrogen removal case. Since this was a scale-up of 80:1, the accuracy of the related cost figures must be considered to be lower than for the other cases.

5.3.4 Energy for Process Heat and Equipment Drivers

All reported studies made efficient use of clean reject gas for process heat. However, several different approaches were used for major equipment drivers, as indicated below.

A. Purchased power for electric motors
B. On-site power generation (gas turbine)for motors
C. Gas fired engines

Approach A could not be used under the guideline for this study.

Cooling was accomplished by cooling water systems in some studies and entirely by air in others.

5.3.5 Operating Labor Requirements

Plant staffing requirements were provided in several reported studies. These were inconsistent and appear to be highly unrealistic in most cases. For example, as little as 2 man-hours per day were recommended for some major subsystems. For this study, 1 to 2 men per subsystem per shift were assumed.

5.3.6 On-Stream Factor

On-stream (operating) factors reported in the references are nearly all 96%. However these often refer to only a subsystem, e.g., desulfurization. When several subsystems operate in series, the factor for the overall system is the product of the subsystem factors. Allowing 96-97% for subsystems, 90% is selected as a reasonable factor for the combined system.

5.3.7 Miscellaneous

There is much opportunity for variety in process configuration, particularly in systems such as membrane and cryogenic. Although certain basic features were observed in certain types of systems, hardly any two were identical. Differences appear in the number of stages, heat interchange schemes, self refrigeration vs. auxiliary refrigeration systems, and others.

5.4 System Design Modifications

In spite of the differences noted above for reported studies, the configurations in these reference studies were not modified except as noted below. The indicated changes were necessary to adhere to a common basis throughout all of the cases.

5.4.1 Power Generation

For those reference studies where purchased power was assumed, a gas turbine generator has been added. The capacity is sufficient to provide power for the upgrading system and the gas pretreatment system.

For those studies where onsite power was generated for the upgrading system, the power system was increased to provide power for the pretreatment system as well.

5.4.2 Compression Requirements

Compressor size and power requirements were increased or decreased, where necessary, to meet the design product gas pressure.

5.4.3 Pressure Related Performance

In those reference cases where system performance was affected by feed gas pressure, modifications were made to reflect improved or degraded performance, as appropriate. Only liquid absorption systems and membranes were significantly affected.

5.5 Cost Basis

Gas costs were calculated generally in accordance with the guidelines established by the Gas Research Institute (GRI)[19].

The reference studies were carefully examined to ascertain the bases for the economics reported. As expected, the bases varied widely and were often incompletely reported. For uniformity, the following basis was established, and economic data from the references were converted accordingly.

5.5.1 Reference Year

Costs are reported in October 1991 dollars. Most reference studies were performed in the mid to late 1980s. The use of cost indexes to convert costs within this time frame is fairly reliable.

5.5.2 Economic Analysis Procedure

A procedure has been developed to calculate the price of gas required to justify the construction of gas upgrading facilities for the various separation technologies and feed gas compositions discussed in this report. When considering an investment in a gas processing facility, an investor takes into account what the price of gas will be over the entire operating life of the facility, which may be 20 years or more, not just the current price, because it is the income stream over the plant's life that will return his investment and make him a profit. If gas prices are anticipated to experience a high growth rate so that income will be higher in later years, then the price in the first year does not have to be as high as it would have to be if lower price growth is anticipated.

For the cases analyzed, the gas prices presented are the required selling prices in the first year of operation to return the investment in 20 years for different anticipated gas price growth rates. These initial prices can help answer the question at what price will an owner of a LQNG reserve decide that it is economic to build a gas processing facility and begin production of his LQNG.

Obviously, the decision will depend upon what the owner anticipates will be the rate at which gas price grows.

Thus, it is important to remember that in the following case studies the results tables show the gas price required in the initial year (not the processing cost) and that with a high price growth the initial year's price can be lower than with low price growth.

The calculation procedure is an adaptation of the economic analysis methodology described in Reference 19. The basic relationship is:

$$UGP_i = (SPI*CCR + VOM + FDC + WC)/(ANBL*PWPE) \qquad (5\text{-}1)$$

where UGP_i (unit gas price) represents the unit price of gas in the initial year of gas sales, SPI (specific plant investment) is the plant investment per annual unit of gas, CCR is the capital charge rate, ANBL is the annualized equivalent over book life, and PWPE is the present worth for price escalation. The variable operating and maintenance cost (VOM), feed cost (FDC), and working capital cost (WC) are the annualized equivalents of the present values of these items. The gas price that is calculated is the price in the initial year, but the calculation takes into account the growth in price over the next twenty years.

Many of the forecasts of energy prices, such as, for example, DOE/EIA, GRI, DRI, etc., are developed and presented on a constant dollar basis. The forecasts consider the question of whether there is growth in the real price of gas. The real price of natural gas may be growing faster than the rate of inflation (positive real growth) or it may be growing more slowly (negative real growth). The gas price term in the above calculation accounts for real price growth, as show by the equation:

$$PW(GP) = GP_0[1 + (1+ESP) + (1+ESP)^2 + ... + (1+ESP)^{n-1}]/n \qquad (5\text{-}2)$$

The present worth of the stream of prices is represented by PW(GP) and is the sum of the price discounted to the initial year. The price growth is characterized by a constant growth rate (ESP). The growth rate term is calculated as some percent of inflation. Thus, if real gas price growth is negative, then gas price is growing at less than 100% of the inflation rate. Variable operating costs are tied to the inflation rate in a similar fashion. The real price escalation is accounted for in the PWPE term in Equation 5-1 (see Appendix B).

The assumption about the cost of feed is an important part of the economic rationale of this analysis. The basic rationale is that the LQNG reservoirs have been found in past exploration efforts and that this gas will be produced only when the cost of upgrading to pipeline quality can be supported. Thus, the minimum market price at which LQNG will be produced is calculated by assuming the raw gas has zero value and calculating the cost to upgrade the gas.

In this analysis, the processing of raw gas to pipeline quality is accomplished in two steps. First, water and hydrogen sulfide are removed; then, in the second step, carbon dioxide and/or nitrogen are removed by various upgrading process options. In Equation 5-1, the feed gas is the product of the first processing step, and the feed cost (FDC) is the cost of water and hydrogen sulfide removal from a raw gas valued at $0/MSCF.

A complete description of the economic analysis procedure is presented in Appendix B, which includes the output from a sample computer run for one of the study cases. The spreadsheet program has been provided to METC.

5.5.3 Economic Assumptions

The economic assumptions used in the case studies are listed in Table 5-3.

Table 5-3

ECONOMIC ASSUMPTIONS

Project Life, yr	20
Tax Life, yr	10
Federal and State Income Tax, %	40
Financing - Debt, %	20
- Common Stock, %	80
Return on Equity, %	14.2
Return on Debt, %	9.0
Price Growth, % of Inflation	50
Inflation, %	5
Interest on Debt, %	11.3
Interest on Construction Loan, %	12.5

5.5.4 Other Factors Affecting Capital Costs

Since most regions of the U.S. have a sales tax, a tax of 4% was arbitrarily selected to indicate the added capital cost burden.

Two types of contingency were incorporated into the case studies - project contingency and process contingency. Reference reports used project contingencies varying from 0 to 25%, with the most common being 20%. A value of 15% was selected for this study. This is slightly optimistic in view of the usual definition of this contingency.

The process contingency (process design allowance) allows for the fact that the system being estimated incorporates technology which has not been commercially proven for the application. Values of 10% for membranes and 30% for molecular sieves were selected in accordance with GRI guidelines.

Very few references include the cost of "general facilities" in the reported plant costs. General facilities comprise items such as site preparation, buildings, roads, certain utilities and similar non-process related costs. These often lie in the range of 20 to 35% of the process area costs. A value of 20% has been selected for this study. This is not intended to be optimistic but to reflect the fact that power facilities are costed separately.

5.5.5 Operating Costs

5.5.5.1 Maintenance Costs

Annual maintenance cost is nearly always calculated as a percentage of capital cost. Most often it is in the range of 2 to 4%. This study is based on 4% of total facilities installed cost (TFCI) for process units and 2% for offsites.

Direct maintenance labor cost is assumed to be 60% of total maintenance.

5.5.5.2 Labor Rates

Wage rates in the references range from $14-23/man-hour; $20/man-hour was selected for this study.

5.5.6 Product Gas Price

A procedure has been developed to calculate the price of gas required to make investment in upgrading facilities viable for the gas producer/processor who has discovered reserves of LQNG. The required price of gas is determined by summing the annual equivalents of the present worths of the following items, expressed in terms of a unit of product:

Cost of Process Facility, including Return (CPF)
Operating and Maintenance Cost (OMC)
Feedstock Cost (FC)
Cost of Working Capital (CWC)

The sum of these items is set equal to the annualized present worth of the revenue from the sale of a unit of product (RPS), as shown in the following equation:

$$CPF + OMC + FC + CWC = RPS \tag{5-3}$$

The revenue from sales is a function of the price of pipeline quality gas at the time of unit start-up and the way that price grows over time. In the calculation routine gas price is projected to grow at a constant rate and that estimate of price growth is entered as a percent of the inflation rate. The resulting required gas price is for the initial year but is a function of the assumed price growth rate.

5.5.6.1 Fuel Cost

Fuel cost refers to the cost of the untreated feed gas received by a system. The wet sour feed gas is assumed to have no dollar value, since it will come from a shut-in well whose exploration and drilling costs have been written off.

For convenience, a gas processing cost was calculated for the sweet dry gas leaving the pretreatment system, assuming an average diluent content of 15%. This cost was then used to establish the feed gas cost to the competing upgrading processes.

5.5.6.2 By-Product Credit

No credit was allowed for reject nitrogen or carbon dioxide, low grade fuel gas, or export steam. The value of elemental sulfur was calculated for purposes of comparison, but was not used in the basic gas cost calculation.

5.6 Plant Performance and Economic Data

5.6.1 Pretreatment Area

5.6.1.1 Plant Description

Wet sour gas is pretreated sufficiently to make it transportable without corrosion or plugging. The treatment steps are shown in Figure 5-1. The crude gas is first sweetened in the selective solvent desulfurization system, which minimizes carbon dioxide absorption. The wet gas is next sent to the dehydration system, where it is dried to pipeline quality. Additional drying is provided in downstream steps, if the upgrading process requires it.

Acid gas, largely hydrogen sulfide, is sent to a sulfur recovery system to produce elemental sulfur. This step is needed whether the sulfur is to be sold or landfilled. Residual gas may contain traces of COS or sulfur dioxide. It is passed through a tail gas cleanup unit to ensure that the vent gas meets air quality requirements.

Figure 5-2 depicts a typical sulfur removal absorption system, the sour gas being cleaned to pipeline quality by countercurrent contact with a solvent in the absorber. Plant fuel gas is obtained by flashing rich solvent before stripping. Flash pressure is adjusted to obtain just enough methane to meet the fuel needs of the pretreatment system. The subsystems are integrated to the degree that lean solvent from this system also serves the needs of the tail gas absorber (Figure 5-3).

The sweet gas remains saturated with water and is dried to pipeline specifications (about 7 lb of water per 10^6 SCFD) in the dehydration system (Figure 5-4). Additional drying or purification is provided in the downstream upgrading system when needed. Water picked up in the absorber is driven off in the fired still. Hot

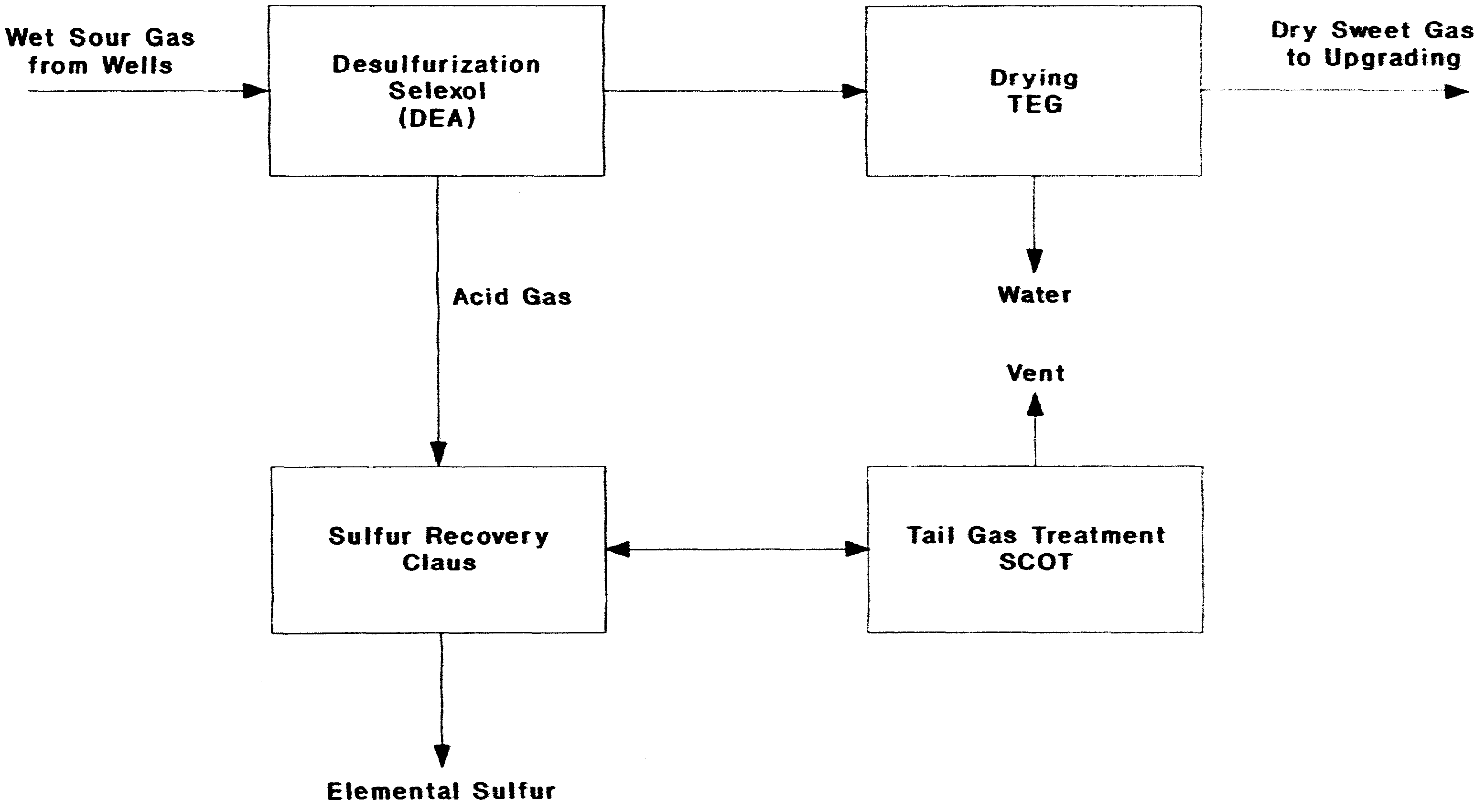


Figure 5-1. RAW GAS PURIFICATION BLOCK FLOW DIAGRAM

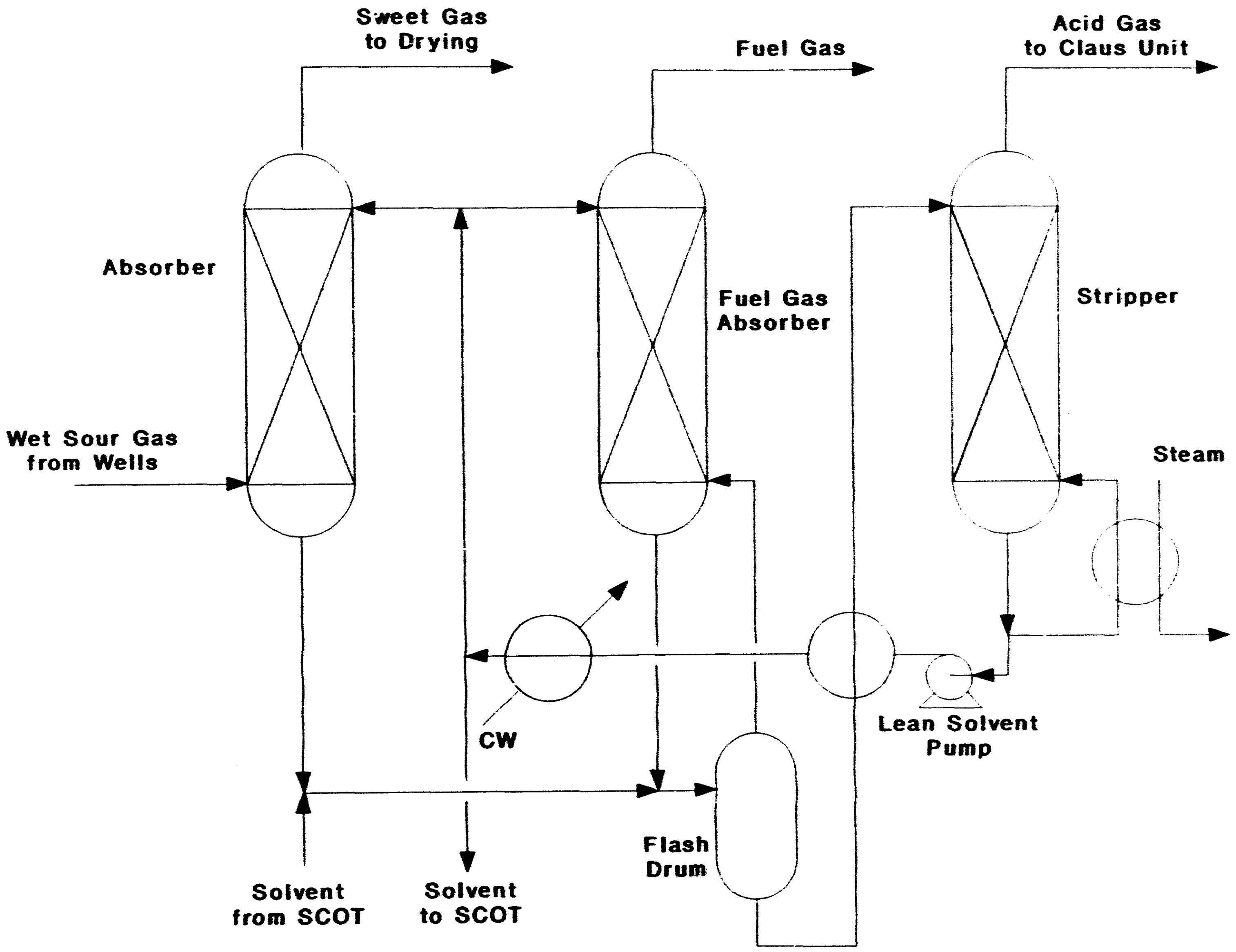
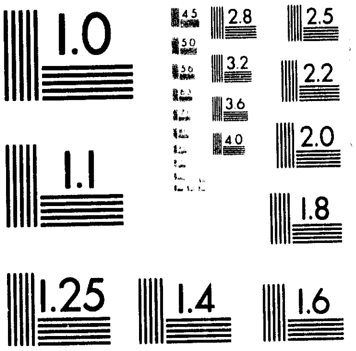


Figure 5-2. TYPICAL FLOW DIAGRAM OF RAW GAS DESULFURIZATION


1.0
4.5
5.0
5.6
2.8
3.2
3.6
4.0
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2.0
1.1
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1.25
1.4
1.6

2 of 2

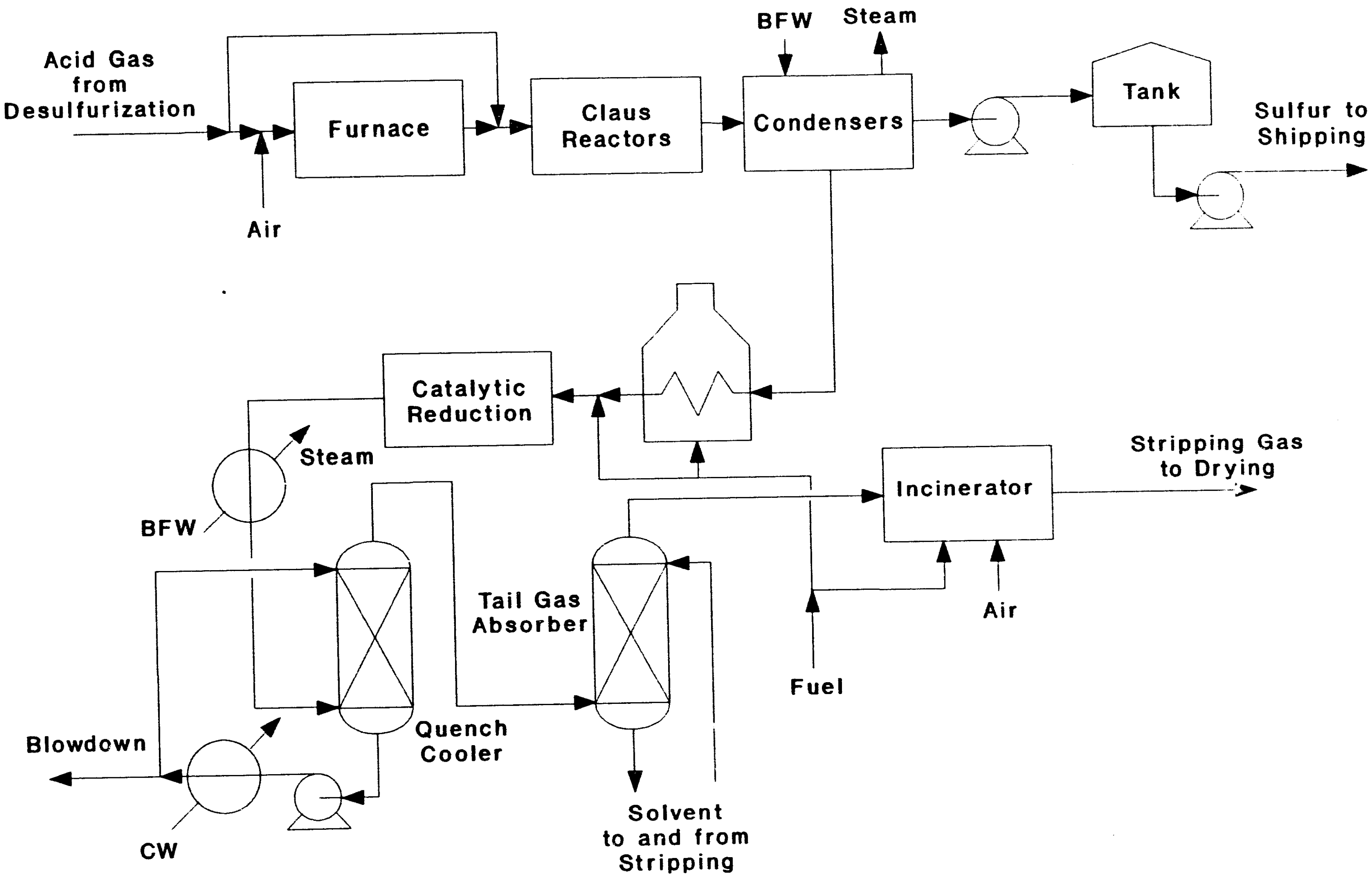


Figure 5-3. TYPICAL FLOW DIAGRAM OF SULFUR RECOVERY AND TAIL GAS TREATING

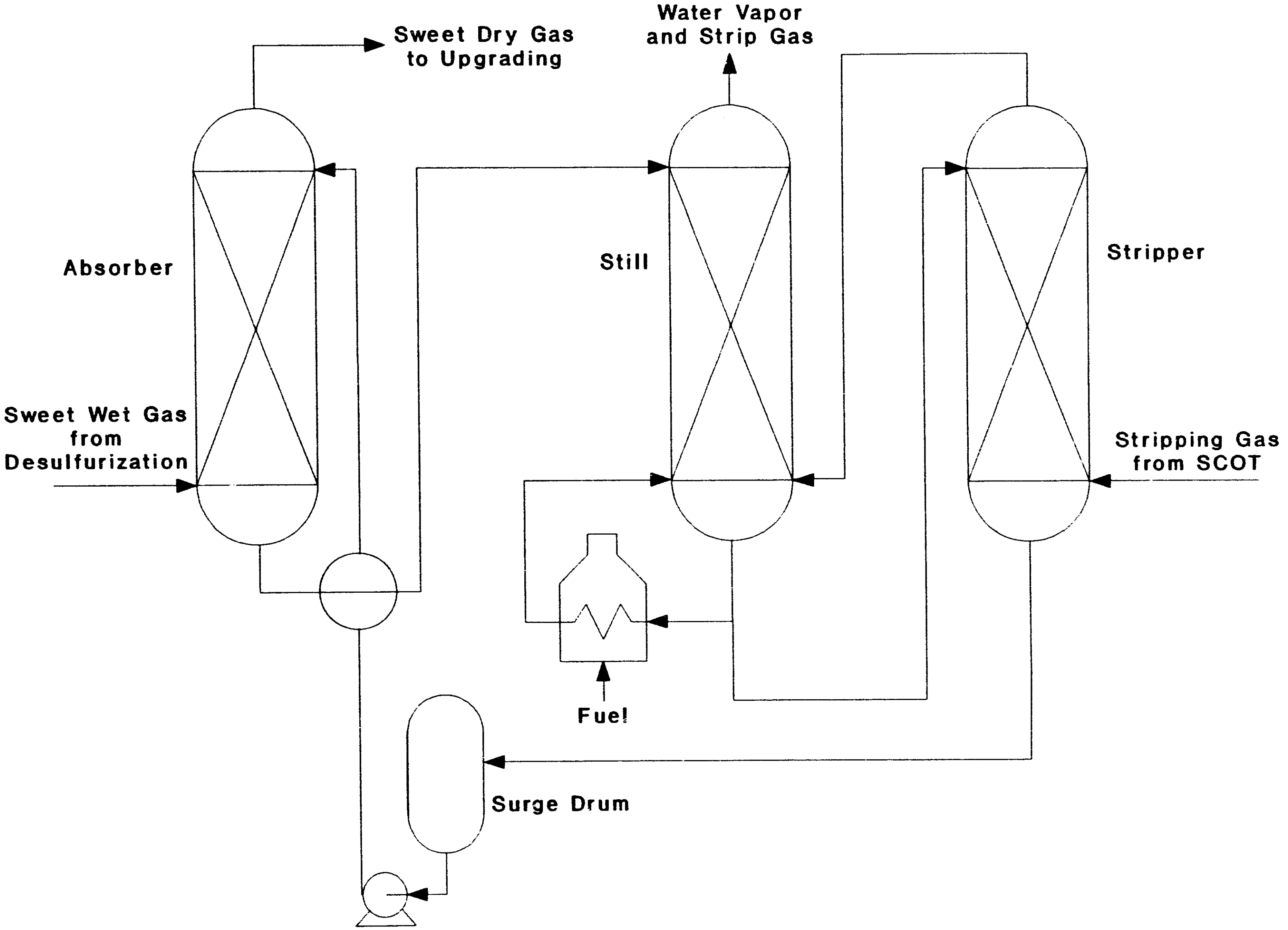


Figure 5-4. TYPICAL FLOW DIAGRAM FOR SWEET GAS DRYING

flue gas from the tail gas incinerator (Figure 5-3) is used to strip the small traces of water left in the lean solvent before it returns to the absorber.

The acid gas is partially combusted to sulfur dioxide which is combined with the residual hydrogen sulfide and sent to a Claus unit, where the gases are catalytically converted to liquid sulfur. The sulfur is of good quality and can be shipped to a purchaser or to landfill disposal, if there is no market.

The residual gas leaving the sulfur condenser normally contains traces of sulfur dioxide and other sulfur compounds. These are catalytically converted to hydrogen sulfide which is absorbed by the lean solvent from the desulfurization system before combusting the remaining gases in the incinerator. The incinerator gas is used to strip water from lean solvent before being discharged to the atmosphere (Figure 5-3).

Sulfur vapors are condensed at relatively high temperature. In the usual approach, boiler feed water is the coolant, and low pressure steam is produced. This is often discarded, as here, since it is in excess of plant needs.

5.6.1.2 Economics

Total plant investment and product gas cost was estimated for the pretreatment subsystem at two levels of inlet sulfur content, as shown in Table 5-4.

Table 5-4

PRETREATMENT CASES

	Base Case	High Sulfur Case
Case Identification	WSL	WSH
H_2S Content, %	0.6	2.7
Wet Sour Feed Gas, 10^6 SCFD	98.4	101.0
Sweet Dry Product Gas, 10^6 SCFD	97.8	97.1
Sulfur, short tons/day	24	112

Gas costs for the base case and the high sulfur case were calculated in accordance with the GRI guidelines. Costs with and without credit for sulfur sales were developed, but the base cost does not include sulfur credit. Results for capital investment and product gas costs are shown in Table 5-5. The base cost, 11.6¢/MSCF, is used as feed gas cost for the downstream upgrading systems in the base set of runs.

Table 5-5

TOTAL PRETREATMENT PLANT INVESTMENT AND PRODUCT GAS PRICE

(October 1991)

Case	WSL	Ref.	WSH	Ref.
Plant Investment, $\$10^6$				
Desulfurization	5.7	20	6.1	21
Dehydration	1.9	22	1.9	21
Sulfur & Tail Gas	4.6	20	10.7	23
Total (TPI)	12.2		18.7	
Product Gas Price, ¢/MSCF				
Without Sulfur Credit	11.6		15.9	
With Sulfur Credit	9.3		5.4	

5.6.1.3 Low Capacity Applications

Natural gas is occasionally found in small fields in sparsely populated areas. Since it may be uneconomical to transport small quantities of gas to major pipelines or other users, such gas must be used locally or else shut in. Potential uses include power for small communities, mining operations, etc. One problem is that such gas may be unusable as it comes from the well head because of sulfur contamination.

Desulfurizing small quantities of natural gas in remote or semiremote areas presents a different set of problems from processing large quantities of gas at a central treating plant. To be able to operate economically, a small plant must have a low capital cost, be able to operate with a small manpower requirement, and produce only easily disposable by-products, since in a remote area it must be assumed that the sulfur is not readily marketable. This means that most of the advanced desulfurization processes which have been developed are not suitable for small capacity applications.

The requirements for low capital and an easily disposable by-product essentially limit the choice of processes to those which (1) use a regenerable absorbent and produce elemental sulfur in a single step or (2) use a throwaway adsorbent capable of being disposed of in an ordinary landfill. Recovering the H_2S as a concentrated stream would not be acceptable, since the requirement for a Claus plant would clearly make the operation uneconomic. Production of sulfuric acid would also be unacceptable because of the difficulty of handling and marketing sulfuric acid in a remote location.

In its simplest manifestation, a desulfurization process that produces sulfur by-product consists of only two vessels, an absorber and a regenerator, plus auxiliary equipments to provide for sulfur recovery and absorbent circulation and makeup. Heat transfer and air supply equipment might also be needed. It is apparent that even in this simple configuration, such a process would not be suitable for completely unattended operation and would probably have to be located where an operator was available at least part time. If the treating plant could be located at the facility utilizing the gas, then it might be possible to share operators.

A plant using a disposable adsorbent would consist essentially of only an adsorption vessel. Such a plant is potentially capable of unattended operation except for periodic replacement of the adsorbent. Rather than a single vessel, the plant would most likely consist of two vessels in series, with the adsorbent in one of the vessel being replaced each time servicing is performed. The order of flow through the vessels would then be reversed to place the freshly packed vessel downstream of the other vessel. This type of arrangement maximizes adsorbent utilization and helps guard against sulfur breakthrough.

The following sections discuss process economics for small capacity applications in more detail.

5.6.1.3.1 Regenerative Absorbent Process

There are two basic routes to production of sulfur from sour natural gas:

1. Solvent absorption of the hydrogen sulfide, followed by partial oxidation of the acid gases and conversion to sulfur via, e.g., Claus.

2. Direct oxidation of the hydrogen sulfide in the natural gas via absorption in a liquid solution containing an oxidizing salt.

At very low gas flows, two step processes, such as absorption followed by Claus, can be expected to be less economical than single step processes. At least one study[24] has verified this.

The most widely used direct oxidation process is Stretford[25] and the closely related Shafer[26] process. These processes are based on the oxidation/reduction of vanadium salts. Unisulf and Sulfolin[25], which are also vanadium based, have a few recent commercial applications.

Processes based on the oxidation/reduction of iron and iron chelates include LO-CAT®, Sulferox, and Hiperon[26]. The latter two appear to have only one commercial installation, while as of 1984 LO-CAT® had at least 20 plants in design or operation, ten of them on natural gas.

The Stretford process has been installed in more than 300 plants around the world and has had good success in many of them. In some more recent applications in high CO_2 environments, performance has been very disappointing, and it has been realized that the chemistry is not fully understood. Also, discharge of vanadium bearing salts has become a greater environmental concern. In view of technical, economic, and environmental concerns, evaluation of Stretford has not been pursued further, and the LO-CAT® process was selected for this study.

Table 5-6 presents the capabilities claimed for the LO-CAT® process by its licensor, ARI Technologies, Inc.[27]

Table 5-6

CAPABILITIES OF THE LO-CAT® PROCESS

H_2S Exit Conc.	- H_2S can be removed to essentially "any level." (Achieved an estimated 5 ppbv H_2S level in an odor elimination application.)
H_2S Inlet Conc.	- 0.01 to 49.5%
Operating Pressure	- 0 to 1500 psig
CO_2 Tolerance	- 95% or more
Capacity	
Gas Flow	- 0.01 to 44 x 10^6 SCFD
Sulfur	- 0.05 to 87.5 LT/D

Figure 5-5 illustrates the application of LO-CAT® to remove sulfur from high pressure natural gas. Sour feed gas passes through a knockout drum to remove entrained hydrocarbons, which are very deleterious to process operation. The gas and the aqueous reactant stream are intimately contacted in the venturi/absorber system, where Fe^{+3} is reduced to Fe^{+2} and elemental sulfur forms. Spent solution is reduced in pressure and sent to the flash tank, where dissolved methane comes off. The solution is contacted with air in the oxidizer, where Fe^{+2} is converted back to Fe^{+3}. Sulfur sinks to the bottom, and sulfur slurry flows to the clarifier filter. The clarified solution is recycled to the oxidizer. Solution from the oxidizer is sent to the venturi/absorber system.

The sulfur cake and adhering mother liquor are periodically transferred to holding facilities by back hoe. The discarded sulfur can vary from a slurry containing 20% sulfur to a wet cake containing 50% sulfur. In the case of the slurry, the liquor will be about pH 8-8.5 and have the following composition[27]:

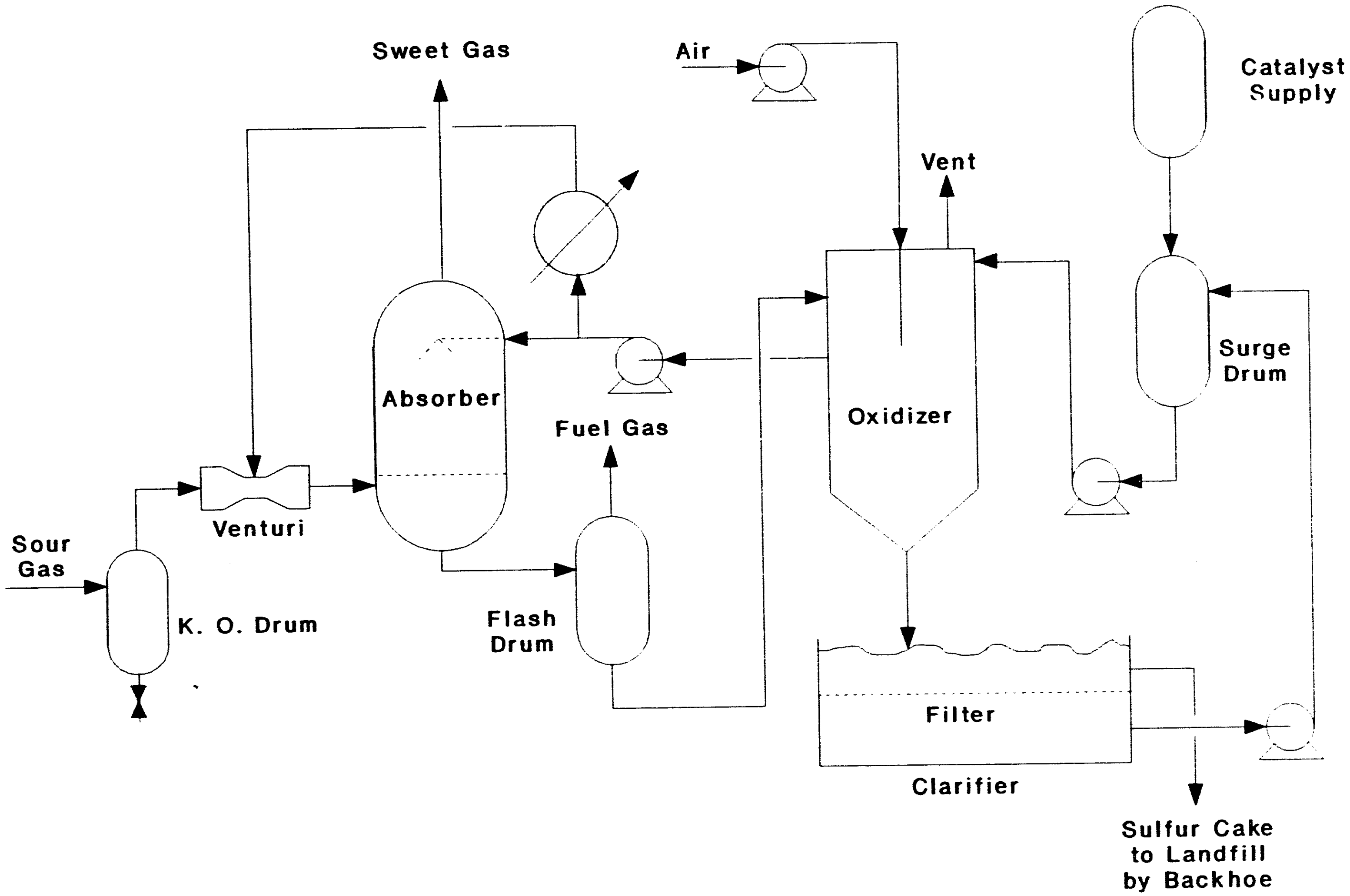


Figure 5-5. TYPICAL FLOW DIAGRAM FOR SULFUR REMOVAL BY LO-CAT® PROCESS

$K_2S_2O_3$	1.87%
K_2SO_4	0.25%
Organics	0.25
Fe	0.06%
Water	97.57%

The organics typically consist of ethylenediamine tetra acetic acid (EDTA), sucrose, antifoam agent, and biocides. The solution is claimed to be nontoxic and environmentally acceptable. Experience at several plants indicates that salt removal via liquor in the cake is sufficient to maintain a proper salt level and no additional bleed is needed.

A LO-CAT® installation[24] for ARCO Oil & Gas Co. in Midland, TX, was selected as typical of a low gas flow sulfur removal system and used as the basis of this study by adjusting conditions to those shown in Table 5-7.

Table 5-7

DESIGN CONDITIONS FOR SMALL CAPACITY PLANT

Inlet Gas Flow	5×10^6 SCFD
H_2S Level	770 ppm
Pressure	800 psig
Temperature	80 °F

Total plant investment for this facility is about $2.2 million, excluding dehydration. The additional capital for this latter operation should have negligible impact on gas cost. Product gas price for the initial year is estimated to be slightly over 70¢/MSCF (mid gas price growth scenario) without credit for sulfur. Sulfur recovered is slightly less than 0.2 ST/day. Several economic studies[26,28] show that, for small plants, the cost of sulfur removal on the basis of cost per ton of saleable sulfur is so high compared to the market price of sulfur that the economics are not greatly affected by credit for sulfur sale.

In contrast to other processes studied, the capital cost for LO-CAT® is governed primarily by the amount of sulfur removed rather than by the gas flow rate. Caution must be used in developing costs for facilities with low gas flow at low to moderate sulfur content. Scaling or extrapolation can lead to highly misleading results.

5.6.1.3.2 Disposable Adsorbent Processes

The SulfaTreat process removes H_2S from natural gas streams by adsorbing it on a dry, free-flowing proprietary adsorbent with a bulk density of about 70 lb/ft^3. This adsorbent is reported[29] to be nontoxic, nonhazardous, and nonpyrophoric in both its as-received and ready-for-disposal forms, and the spent adsorbent can be placed in a nonhazardous landfill. The process can operate at any pressure with an operating temperature greater than 50^oF.

Insufficient information is available to generate an investment cost, but because of the simplicity of the flow diagram, it is expected to be less than half that of LO-CAT®. Operating costs are reported to be $1.69-2.21/lb of sulfur removed. This process could look attractive for a low capacity plant processing gas with a relatively low H_2S content.

Chemsweet is a process similar to SulfaTreat. However, instead of a packed bed, Chemsweet uses a slurry of fine zinc oxide particles suspended in an aqueous solution of zinc acetate. (A dispersant is added to help keep the particles in suspension.) The gas to be sweetened is bubbled through the slurry, and the hydrogen sulfide in the gas reacts with the ZnO to form insoluble ZnS. Carbon dioxide does not react. It is important that the gas be saturated with water to keep from drying up the slurry. Periodically, the slurry is drained from the adsorber and replaced with fresh. It is claimed that, with appropriate authorization, the spent adsorbent can be disposed of in a Class 1 industrial landfill.

Reported[30] operating cost is $4.50 per pound of sulfur removed. Investment costs should be about the same as for SulfaTreat. A possible advantage of Chemsweet is that it may be easier to replace a slurry as opposed to a packed bed.

5.6.1.3.3 Effect of Size and H_2S Content

The effect of size and hydrogen sulfide content on costs for the two types of plant will be somewhat different. This is because operating costs have two components: fixed costs, which are mainly related to investment and labor based items, and variable costs, which relate to consumption of utilities, catalysts and chemicals, etc. The relative importance of these two cost components will be different for the two types of plant.

A plant with a circulating absorbent is more complex than a plant with a disposable adsorbent and will use more labor. Therefore, the investment and labor based items will be a higher fraction of total operating costs for a plant using a circulating absorbent. At a given sulfur level in the feed gas, operating cost per unit of gas processed should moderately decrease with increasing plant capacity, because of economies of scale. Because the absorbent is regenerated and recycled, its cost should not be major factor in operating cost. At a given feed rate, operating cost will increase as H_2S level increases but not at a rate proportional to H_2S content. This is because although circulation rate will increase, absorbent usage should not significantly increase.

Economies of scale will also benefit a plant with a disposable adsorbent, so that operating costs should decrease on a unit throughput basis as plant size increases at a given sulfur content.

On the other hand, adsorbent costs will be proportional to the amount of sulfur removed. Therefore, operating costs will be essentially proportional to H_2S content for a given plant size.

5.6.2 Upgrading Area

The gas upgrading area includes both the process area and the utility area shown on Figure 5-6. Although the plant fuel gas is shown as coming from the sweet dry gas, in many cases it is reject gas, a bleed off from an intermediate stream, or a blend. Table 5-8 presents information on the fuel gas for the various cases.

Table 5-8

METHANE DISTRIBUTION

Case	CO_2 Content, %	N_2 Content, %	Type of Process	Plant Fuel Gas, Btu/SCF max.	Reject Gas, Btu/SCF max.	Methane Recovery, %
WSH			Amine 2.7% H_2S	varied	low	98.8
6NC	6		Cryogenic	400	low	96.0
13NC	13		Cryogenic	870	10	93.8
25NC	25		Cryogenic	750	10	94.1
6NM	6		PSA	850	850	84.5
25NM	25		PSA	350	330	82.4
4CM		4	Membrane	960	165	98.5
7CM		7	Membrane	930	220	97.9
15CM		15	Membrane	470	150	95.5
4CA		4	Amine	990	low	98.1
9CA		9	Amine	990	low	96.5
NCO	6	25	Amine Cryogenic	760	10	91.3

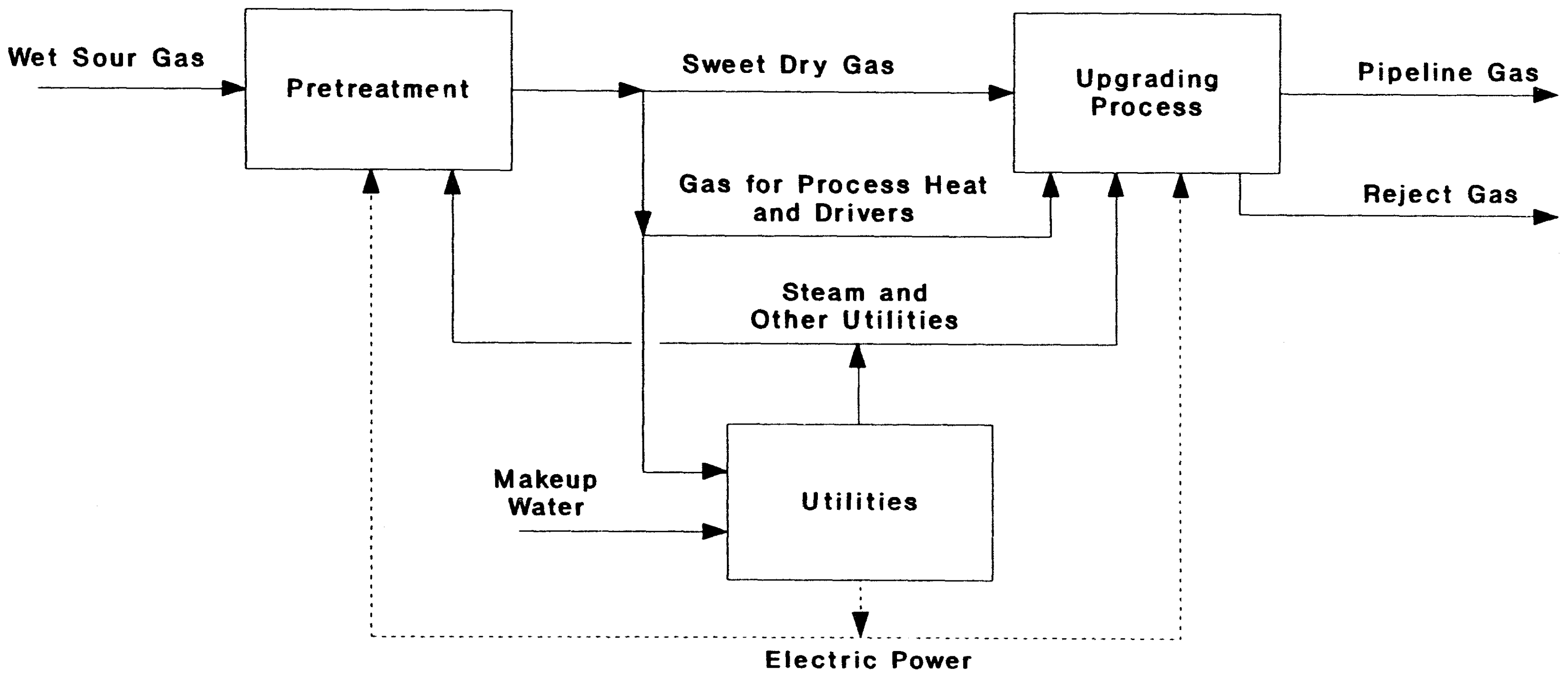


Figure 5-6. BLOCK FLOW DIAGRAM OF TYPICAL UTILITY DISTRIBUTION

The fuel values in the table above can be changed within limits by adjusting operating conditions or equipment design. Btu values can also be adjusted by blending for maximum utilization of reject gases.

Since fuel gas is used for burners, gas engine drives, and power generation turbines, there are limitations on its properties. It may be too low in heating value for one or more of these applications, necessitating the use of some pretreated or even pipeline quality gas. Some typical requirements are:

Steam raising or process heat	80 Btu/scf minimum
Gas turbine generators	300 Btu/scf minimum
Compressor drives	400 Btu/scf minimum

The Utilities area provides electric power for both the pretreatment and upgrading areas. Other utilities, such as cooling water, plant and instrument air, potable water, fire water, etc., are supplied as needed.

5.6.2.1 Cryogenic Nitrogen Removal

A simple version of a cryogenic nitrogen rejection unit is shown on Figure 5-7. The key piece of equipment is the nitrogen-methane tower which fractionates liquefied nitrogen and methane. A single column (as used in this study) is normally used, when nitrogen content is less than about 20%, and a two column system for higher percentages. Since the preferred operating pressure is about 350 psig, the feed gas pressure must be reduced. However, this gas expansion helps provide some of the needed refrigeration, as does the expansion of reject nitrogen. The low column pressure necessitates recompression of product gas to pipeline pressure. Extensive use of heat interchange conserves energy needed for refrigeration.

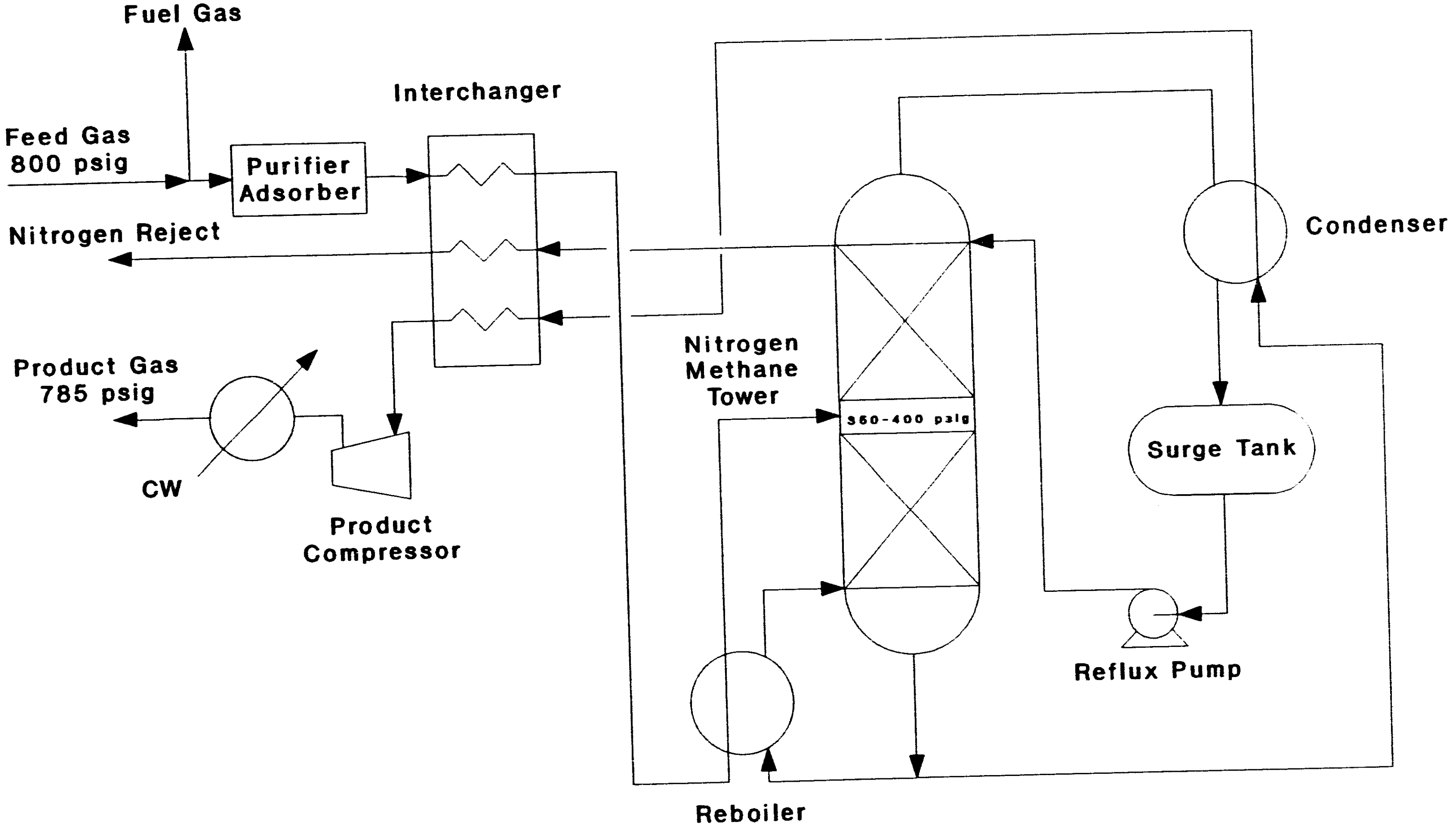


Figure 5-7. TYPICAL FLOW DIAGRAM OF CRYOGENIC NITROGEN REJECTION UNIT (NRU)

Very low levels of carbon dioxide (10-50 ppm) and water are necessary to keep the system from plugging. These materials are removed in the purifier.

Economics have been established for three levels of nitrogen. The cases are defined in Table 5-9.

Table 5-9

CRYOGENIC NITROGEN REMOVAL CASES

Case Identification	6NC	13NC	25NC
Reference	31	32	31
N_2 Content, %	6	13.7	25
Feed Gas Rate, 10^6 SCFD	88.2	92.1	109.4
Product Gas Rate, 10^6 SCFD	<---------80-84-------->		

The total plant investments and product gas prices for the three cases listed above are presented in Table 5-10.

Table 5-10

CAPITAL INVESTMENT AND GAS PRICE FOR CRYOGENIC NITROGEN REMOVAL

Case	6NC	13NC	25NC
Total Plant Investment, $ Million	21.5	22.4	33.2
Gas Price in Initial Year, ¢/MSCF			
Low Gas Price Growth	38.9	43.7	55.8
Mid Gas Price Growth	32.1	36.1	46.1
High Gas Price Growth	21.1	23.7	30.3

5.6.2.2 Molecular Sieve Nitrogen Removal

Nitrogen can be separated from methane by adsorbing the methane on wide-pore active carbon, sometimes referred to as molecular sieves. A typical system for accomplishing this by pressure swing adsorption (PSA) is shown in Figure 5-8. Separation is poor at high pressure, so feed gas pressure must be reduced to about 200 psig before the gas enters the adsorbent bed.

Each bed operates on a cycle consisting of four major steps.

1. Adsorption - Feed gas passes through until the bed is saturated with methane.
2. Depressuring - The bed pressure is reduced and methane starts to desorb.
3. Evacuation - The bed is evacuated by vacuum pump to completely remove methane.
4. Repressuring - Bed pressure is brought up to the operating level before the bed goes back on stream.

Bed A in Figure 5-8 is shown in the adsorbing mode. Reject nitrogen flows to the reject header for use as fuel, with the excess being discarded. Bed D is shown in the evacuation mode with the desorbed methane going to the product gas header and being compressed to pipeline pressure.

Economics have been established for two levels of nitrogen. The two cases are defined in Table 5-11.

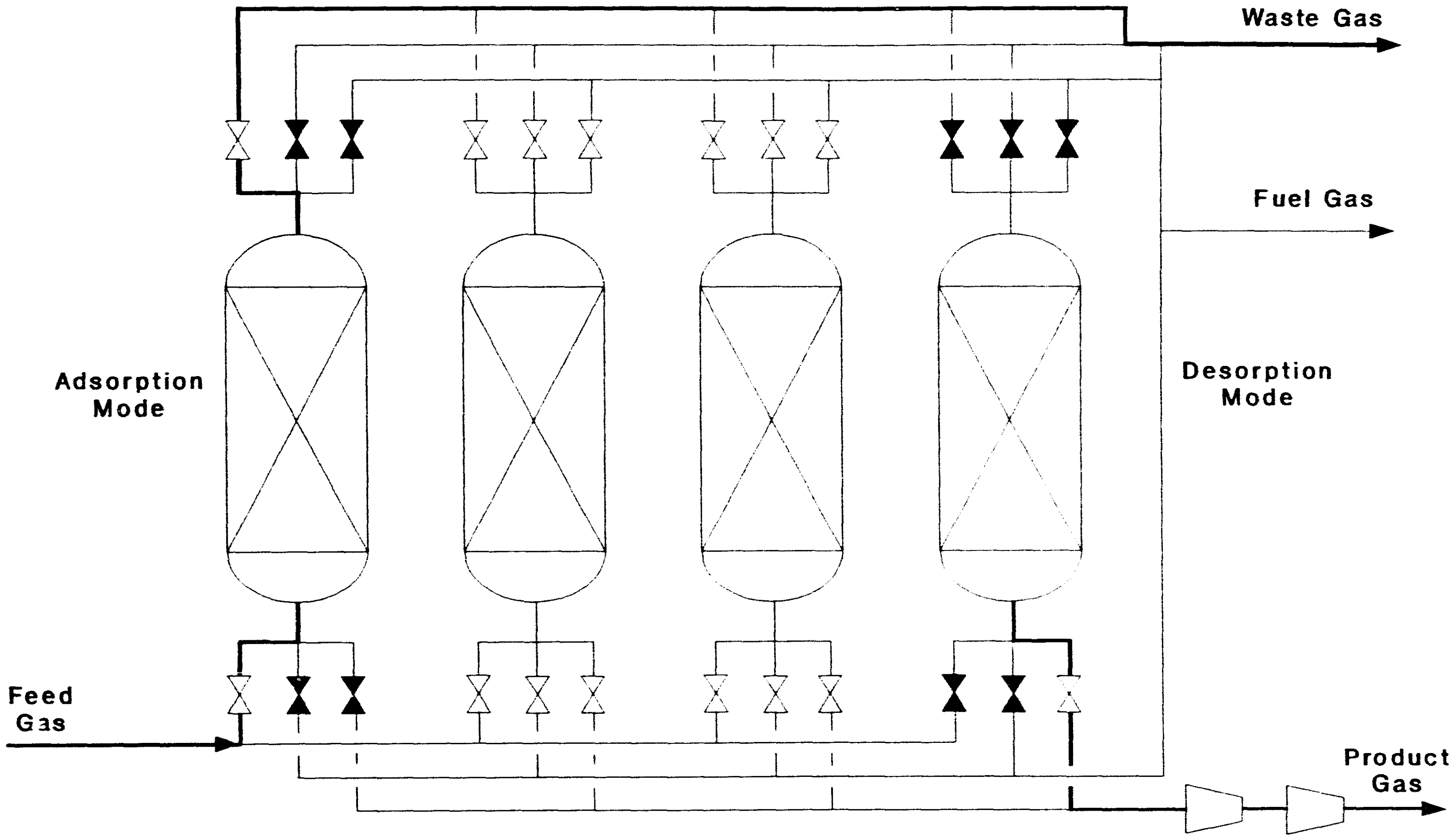


Figure 5-8. TYPICAL CARBON BED ADSORPTION MODULE PRESSURE SWING ADSORPTION (PSA)

Table 5-11

MOLECULAR SIEVE NITROGEN REMOVAL CASES

Case Identification	6NM	25NM
Reference	33	33
N_2 Content, %	6	25
Feed Gas Rate, 10^6 SCFD	88.2	111.1
Product Gas Rate, 10^6 SCFD	73.0	71.15

The total plant investment and the product gas cost for these cases are shown in Table 5-12.

Table 5-12

CAPITAL INVESTMENT AND GAS PRICE FOR MOLECULAR SIEVE NITROGEN REMOVAL

Case	6NM	25NM
Total Plant Investment, $ Million	27.1	31.0
Gas Price in Initial Year, ¢/MSCF		
Low Gas Price Growth	51.0	60.9
Mid Gas Price Growth	42.1	50.3
High Gas Price Growth	27.7	33.0

The capital cost (TPI) includes a process design allowance (PDA) of 30%. Deletion of this allowance would reduce the TPI by 25-30% and the gas cost by 10-15%.

The accuracy of the above costs is probably low because they have been scaled from a plant of very low capacity[33]. Economy of scale is primarily applicable to the compression equipment, while the adsorption equipment consists of parallel modules. Since a similar situation exists for membrane systems, whose scale-up is better known, the scale-up factors for PSA have been assumed to be the same as for membranes.

5.6.2.3 Carbon Dioxide Removal by Membrane

A wide variety of configurations is possible for membrane systems. A two stage system, as shown on Figure 5-9, is probably one of the most suitable for minimum loss of methane. Feed gas is preheated to ensure that no moisture condenses on the membrane. In the first stage, carbon dioxide and some methane permeate through the membrane. Sufficient CO_2 is removed so that the exit non-permeate meets pipeline specifications. The permeate passes through a second stage, where CO_2 with relatively little methane permeates through the membrane and is discarded. The non-permeate from the second stage is recycled to the first stage for methane recovery.

Economics have been established for three levels of carbon dioxide. These cases are defined in Table 5-13.

Table 5-13

MEMBRANE CARBON DIOXIDE REMOVAL

Case Identification	4CM	7CM	15CM
Reference	34	35	34
CO_2 Content, %	4	7	15
Feed Gas Rate, 10^6 SCFD	85.5	89.2	97.8
Product Gas Rate, 10^6 SCFD	82.1	83.0	80.8

The total plant investments and the product gas costs are show in Table 5-14. The TPI values include a process design allowance of 10%. Deletion of this PDA would result in a capital cost reduction of nearly 10%, and a gas cost reduction of about 3-4%

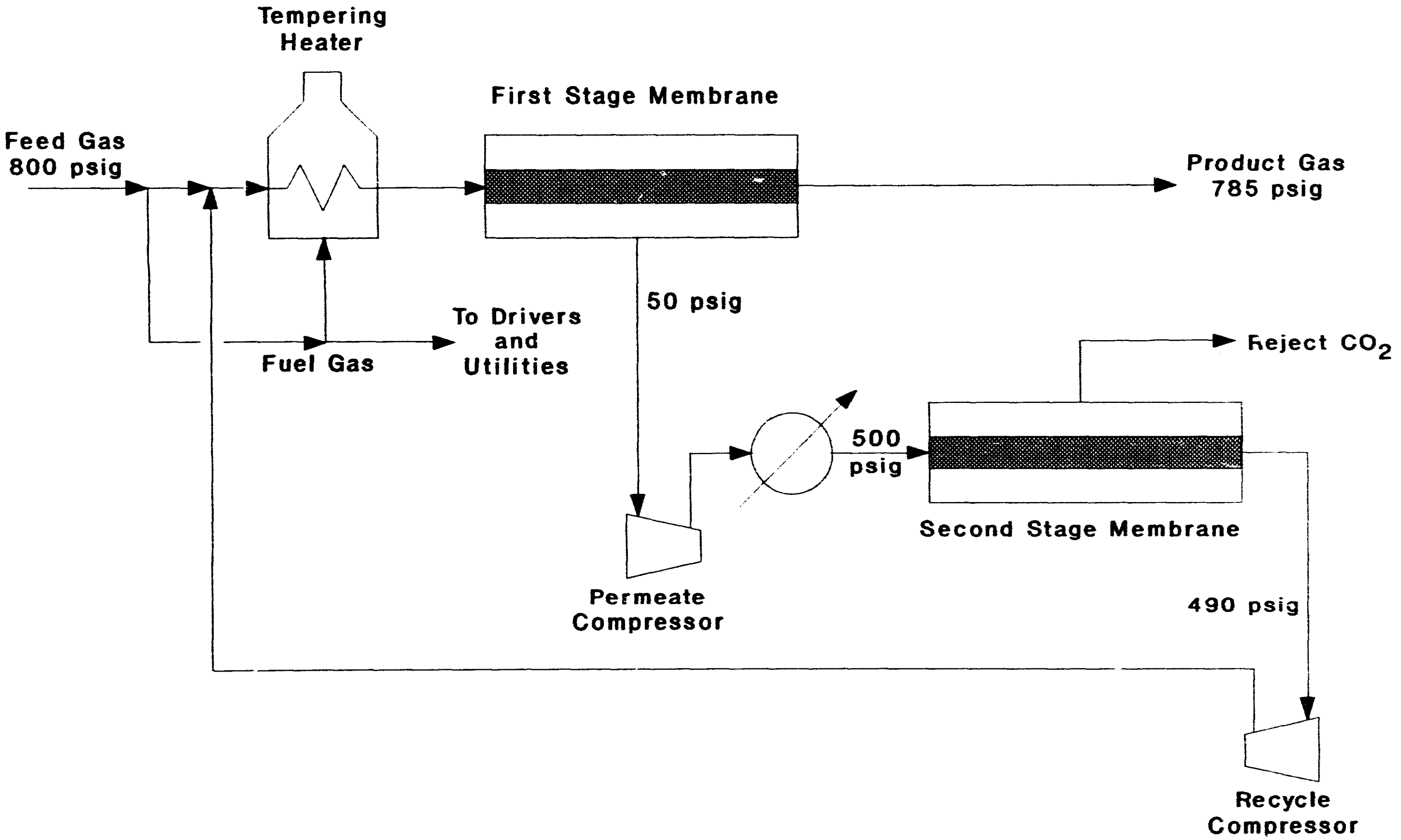


Figure 5-9. TYPICAL FLOW DIAGRAM OF TWO-STAGE MEMBRANE FOR CARBON DIOXIDE REMOVAL

Table 5-14

CAPITAL INVESTMENT AND PRODUCT GAS PRICE FOR CARBON DIOXIDE MEMBRANE SYSTEM
(October 1991)

Case	4CM	7CM	15CM
Total Plant Investment, $ Million	8.6	7.6	17.3
Gas Price in Initial Year, ¢/MSCF			
Low Gas Price Growth	24.1	23.6	36.5
Mid Gas Price Growth	19.9	19.4	30.1
High Gas Price Growth	13.1	12.8	19.8

5.6.2.4 Carbon Dioxide Removal by Amine

The system for removing carbon dioxide is essentially the same as that shown on Figure 5-2. However, it must be placed upstream of dehydration. A different solvent with more capacity is used, since there is no need for selectivity between acid gases, as there may be when removing hydrogen sulfide. This system is artificial in the sense that, if both hydrogen sulfide and carbon dioxide are present in the feed, they would almost certainly be removed in a single acid gas system.

Economics were evaluated for two carbon dioxide levels, as defined in Table 5-15.

Table 5-15

AMINE CARBON DIOXIDE REMOVAL

Case Identification	4CA	9CA
Reference	36	36
N_2 Content, %	4	9
Feed Gas Rate, 10^6 SCFD	86.4	91.1
Product Gas Rate, 10^6 SCFD	81.4	80.1

Results of these case studies are presented in Table 5-16.

Table 5-16

CAPITAL INVESTMENT AND GAS PRICE FOR CARBON DIOXIDE REMOVAL BY AMINE
(October 1991)

Case	4CA	9CA
Total Plant Investment, $ Million	9.3	11.5
Gas Price in Initial Year, ¢/MSCF		
Low Gas Price Growth	27.1	30.7
Mid Gas Price Growth	22.3	25.3
High Gas Price Growth	14.7	16.6

5.6.2.5 Upgrading Gas with Both Carbon Dioxide and Nitrogen

As noted in the preceding section, it is logical to remove all acid gases in a single scrubbing system. In the case presented here, that has been done, and the dehydration unit has been located downstream of acid gas cleanup. Gas leaving dehydration passes through a cryogenic NRU for nitrogen removal. The total system then resembles a combination of the subsystems depicted in Figures 5-2, 5-4, 5-5, and 5-7. This case is referred to as Case NC, and results are shown in Table 5-17.

Table 5-17

UPGRADING GAS WITH BOTH CARBON DIOXIDE AND NITROGEN
(October 1991)

Case Identification	NC
Carbon Dioxide, %	6
Nitrogen, %	25
Feed Gas, 10^6 SCFD	121.6
Product Gas, 10^6 SCFD	78.9
Total Plant Investment, $ Million	54.5
Gas Price in Initial Year, ¢/MSCF	
Low Gas Price Growth	34.8
Mid Gas Price Growth	53.0
High Gas Price Growth	64.2

5.7 Comparison of Upgrading Processes

Although capital costs have been established, it is not particularly useful to compare them. The reason for this is that the various reference studies put different emphases on capital costs vs. operating costs. Some chose to add costly equipment or subsystems to save on energy requirements, thereby increasing capital costs. Others strove to maintain capital cost at a minimum. Product gas required price is a more useful basis of comparison, since both capital and operating costs contribute to its determination.

Figure 5-10 shows the cost of removing carbon dioxide from LQNG, presented in terms of the required initial selling price of gas to obtain an acceptable return on investment, assuming future product gas prices increase at the rate of inflation (the mid price growth scenario). Figure 5-10 compares the removal cost for an amine based CO_2 removal system and a membrane based system. The costs

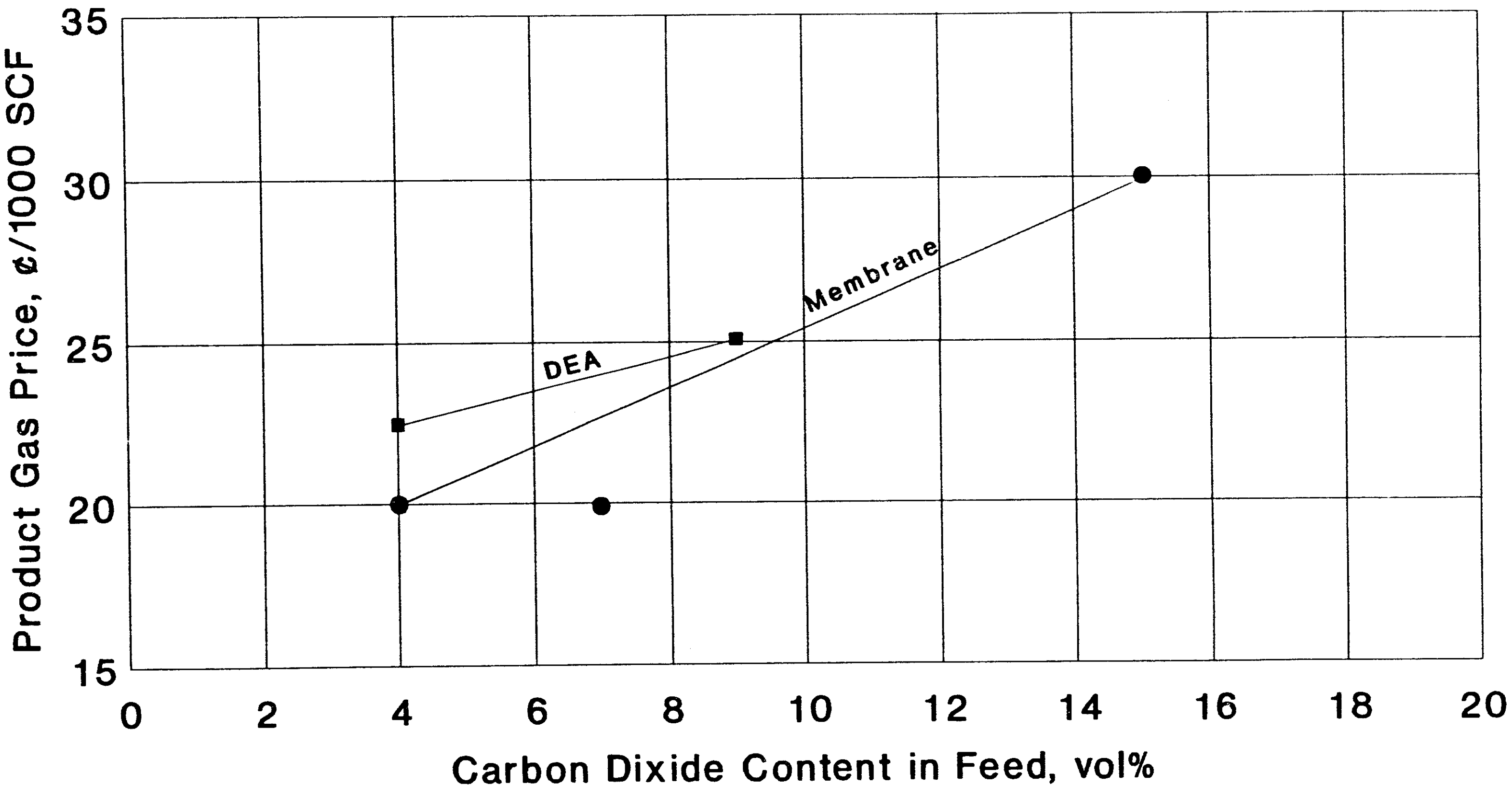


Figure 5-10. CARBON DIOXIDE REMOVAL
PRODUCT GAS PRICE VS. CARBON DIOXIDE CONTENT

for these alternative systems are very close, there being no significant difference within the accuracy of the cost estimating procedure. The deviation of the point for the membrane based system at 7% CO_2 is attributable to using a different reference source for the cost estimate. The prices on Figure 5-10 are in terms of ¢/1000 SCF rather than ¢/10^6 Btu. If this latter basis were used, the relationship between the two curves would be slightly different, since the membrane system produces a gas with about 2% carbon dioxide, while the amine system produces a gas with almost no CO_2.

Assuming the mid gas price growth case, the initial prices required to support nitrogen removal from gases with no CO_2 content are given in Figure 5-11. The lower curve is based on the use of a conventional cryogenic nitrogen removal process. The use of pressure swing adsorption (PSA), employing molecular sieves, is represented by the upper curve. Although PSA is estimated to be the more expensive nitrogen removal route, it is a less mature technology, and future cost reductions could make it cost competitive with cryogenic processing.

These estimates show that nitrogen removal is about one-third more expensive than carbon dioxide removal. One case with both CO_2 and N_2 removal was estimated. The price required for upgrading a gas containing 25% N_2 and 6% CO_2 was 53¢/MSCF, compared with 46.1¢/MSCF for a gas containing 25% N_2 but no CO_2. Thus, the cost of incremental CO_2 removal is less than 7¢/1000 SCF, compared with about 24¢/1000 SCF for removing the same amount of CO_2 from a gas containing no nitrogen.

The impact of three gas price growth scenarios is shown in Figure 5-12. The low price growth scenario assumes gas prices grow at only 50% of the rate of inflation (i.e., actually decline in real terms). The mid case assumes that gas prices grow at the same rate as inflation, meaning they are constant over time in real terms,

Figure 5-11. NITROGEN REMOVAL
PRODUCT GAS PRICE VS. NITROGEN CONTENT

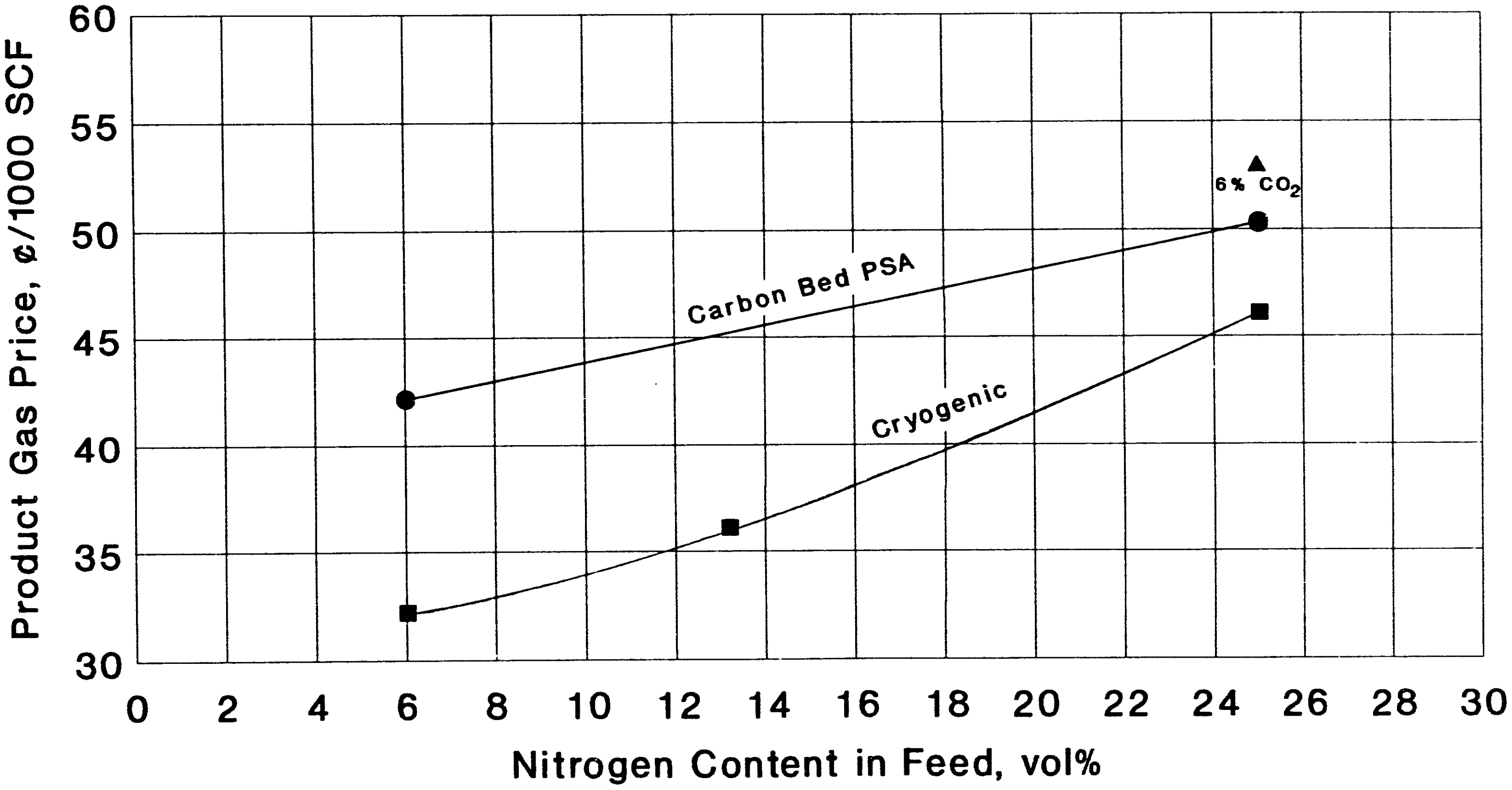
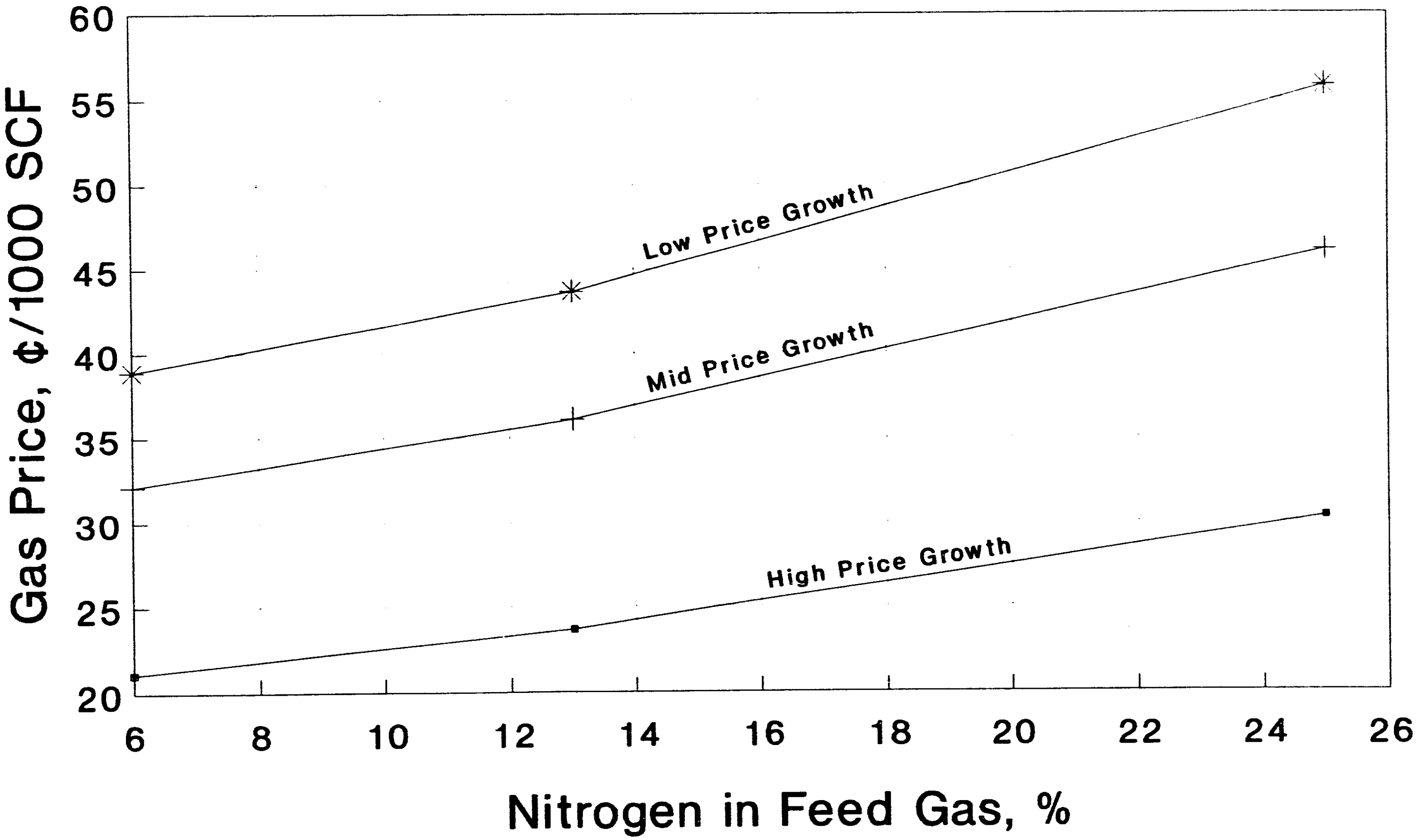


Figure 5-12

CRYOGENIC UPGRADING OF HIGH N_2 LQNG

Required Initial Gas Price to Cover Processing Cost



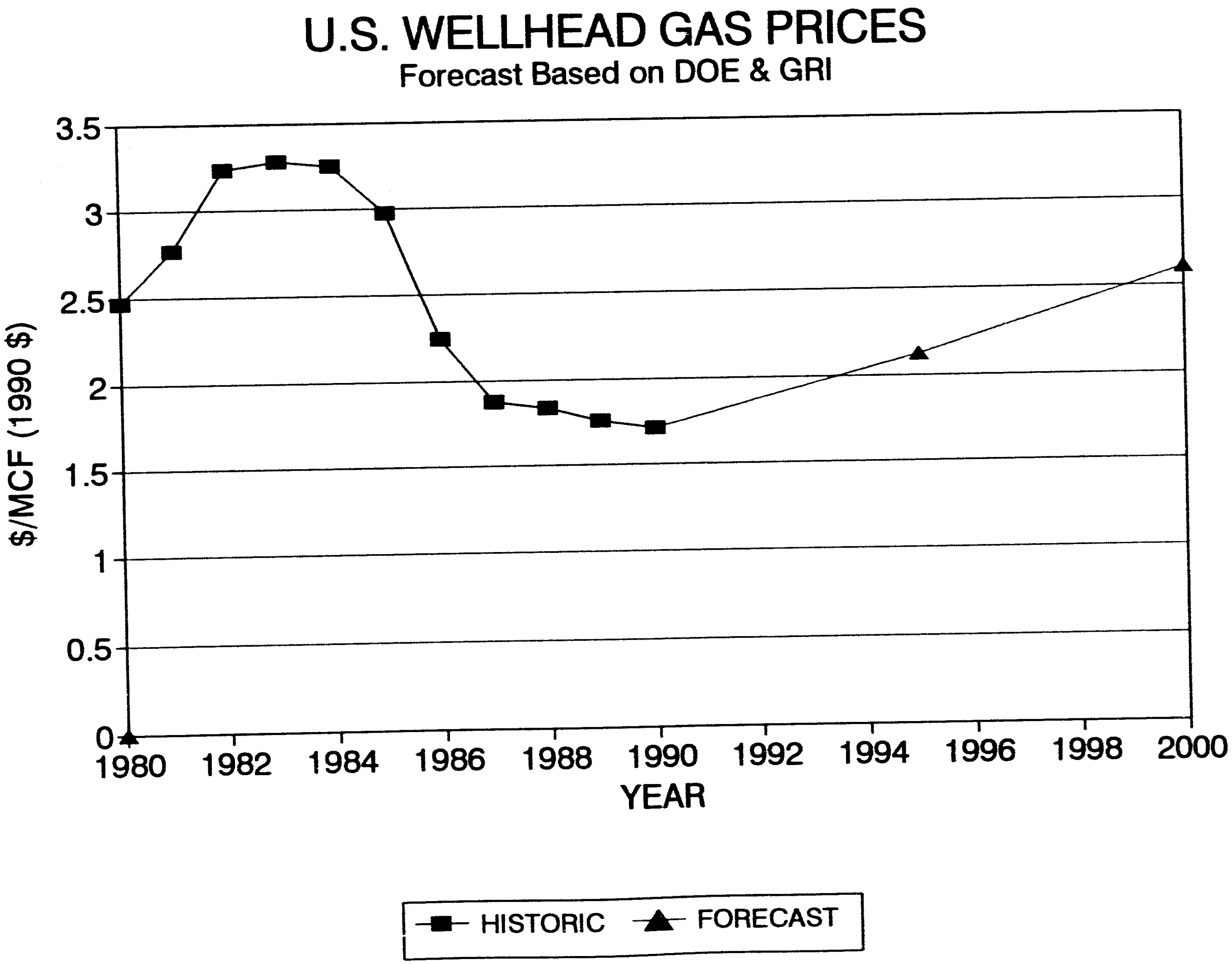
and the high price growth scenario assumes that prices grow at twice the rate of inflation. Figure 5-12 shows the initial required selling prices for the cryogenic N_2 cases for the three price growth scenarios. All the other cases were also calculated for the three scenarios, and results are given in prior sections describing the upgrading process options investigated. Going from the low price growth case to the high price growth case cuts the initial required selling price in half.

The price growth path is clearly important in assessing whether investment in LQNG is attractive. It is valuable to compare gas price history for the past decade with forecasts of future prices. During the past decade, U. S. gas prices have fallen on a current dollars basis and declined even more steeply on a constant dollar basis. Forecasts by DOE/EIA and GRI for the next decade project a dramatic departure from past history, and prices are expected to grow at approximately twice the rate of inflation (which is now approximately 4%) during the decade of the 90's, as show in Figure 5-13.

As can be seen by comparing the initial price required with the average projected prices of Figure 5-13, it appears that upgrading almost any LQNG with less than 25% N_2 or CO_2 would be economic. However, gas processors may be concerned about the timing of their investment; that is, they may be wary of forecasts and believe that by deferring their investment until real price growth is seen, they will improve their return on investment and enhance the value of their resource in the ground.

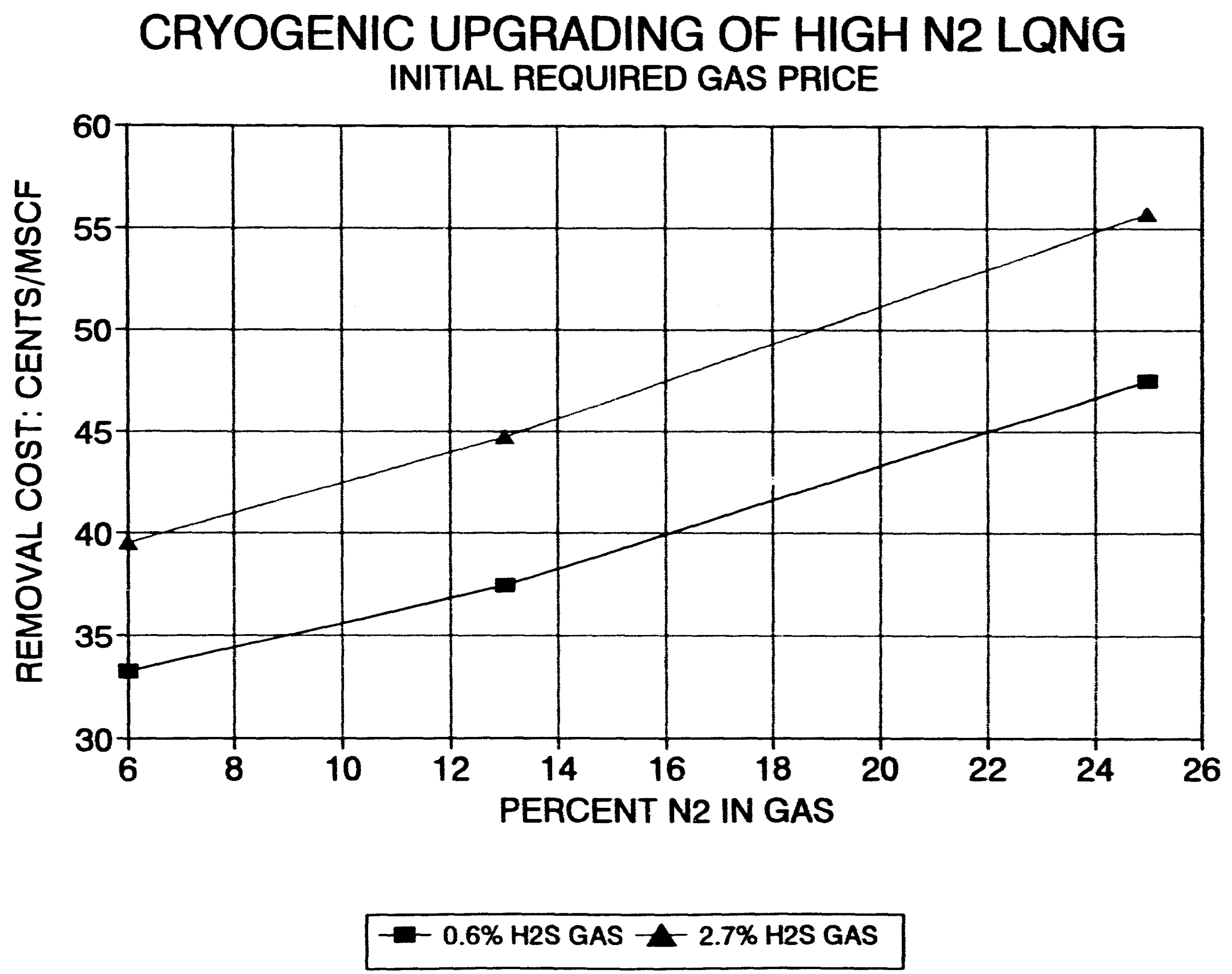
The cases which compare the effect of higher H_2S content in the raw feed gas are shown in Figure 5-14. The cost of preprocessing 2.7% H_2S gas is a little over 4¢/1000 SCF more than the cost of treating 0.6% H_2S gas. Since the economics for upgrading are based on a unit of product gas, the pretreating cost for H_2S removal is spread

Figure 5-13



U.S. WELLHEAD GAS PRICES
Forecast Based on DOE & GRI

Figure 5-14


CRYOGENIC UPGRADING OF HIGH N2 LQNG
INITIAL REQUIRED GAS PRICE
REMOVAL COST: CENTS/MSCF
60
55
50
45
40
35
30
6
8
10
12
14
16
18
20
22
24
26
PERCENT N2 IN GAS
0.6% H2S GAS
2.7% H2S GAS

over fewer units of product as N_2 content increases. Thus, for a 25% N_2 gas, the added cost to pretreat increases to 6¢/MSCF.

The presence of heavier hydrocarbons (ethane+) has not been addressed in this study. If hydrocarbons heavier than methane are present in significant quantities, a subsystem can easily be inserted in the processing train for their recovery. Since these by-products have considerable value, the addition of the subsystem can easily be economically justified under normal market conditions, and the economics of the whole upgrading system will be more attractive.

The economic evaluation of upgrading processes has shown that currently existing processes can upgrade LQNG to pipeline quality material. Newer processes do not appear to have significantly better economics--in fact they appear only equal or slightly more costly. Improvements in existing or emerging processes could improve the economics; however, the main obstacle to utilization of LQNG resources is the current low price of gas and the reluctance of gas processors to make investments until price improvement can clearly be seen.

6.0 RESEARCH NEEDS AND FIELD TESTING

The Gas Research Institute has long had an ongoing program concerned with natural gas processing. In 1988, GRI began a new aspect of the program emphasizing the utilization of LQNG in the U.S. Early phases of the program investigated the extent and composition of LQNG sources; results are summarized in Appendix A. The more recent focus has been to evaluate and develop advanced processes for upgrading natural gas.

Objectives of the GRI program are to decrease the cost of producing existing gas sources and to expand gas reserves by increasing the feasibility of producing low-quality gas sources profitably. The program is intended to emphasize research on and development of small-scale processing systems[6]. Aspects of the work include:

(1) Studies of the resource base in the U.S.
(2) Exploratory research on new separation processes.
(3) Field experiments on emerging technology for upgrading.
(4) Research on associated materials and instrumentation.
(5) Economic assessment of new technological approaches.

METC has cooperated in the GRI program[37]. In addition, processing for gas cleanup in connection with other advanced developments have been investigated at METC, including membranes and instrumentation[38]. The already ongoing level of research may not warrant much expansion in view of the fact that demand and price for natural gas continue to remain depressed.

6.1 Carbon Dioxide Removal

The use of solvent scrubbing systems has been thoroughly explored and developed for a wide range of CO_2 concentrations. There is little incentive for further research since removal costs seem to have reached a plateau. Incremental cost reduction is conceivable with improved solvents having higher capacity or other advantages. Screening of new solvents should continue.

Membrane systems have been demonstrated to be competitive and even superior to solvent systems for some applications. There is potential for improvement in the membrane material itself. A better combination of permeance and selectivity could reduce membrane area and/or recycle power requirements. Evaluation of new materials for these properties and membrane life could lead to significant cost reduction.

Extension of cryogenic systems and molecular sieves to the compositions encountered in the majority of LQNG fields has not been promoted by licensors of these processes who apparently do not feel they would be competitive. Some activity has been observed in the promotion of hybrid systems[39].

6.2 Nitrogen Removal

At present, the only commercial processes for nitrogen removal are cryogenic. Potential for improvement would appear to lie mainly in optimization of process configuration rather than research.

Since cryogenic approaches are costly, there is incentive for research in this area. New concepts[40] being investigated include:

- Adsorption of methane on wide pore carbon molecular sieves
- Absorption of methane in solvent
- Reaction of methane with water to form hydrates

GRI is investigating the wide pore carbon approach (PSA), and economics based on their studies have been included in this report. Performance data for this process needs to be confirmed in field tests, and a cost estimate of a large scale plant should be made. It is felt that data currently available are not adequate to ascertain its true potential.

GRI has investigated two oil absorption processes, one at cryogenic temperature[41]. Neither process has operated in the configurations studied, as far as is known. The low temperature Mehra Process™ produces pipeline quality gas at a slightly lower cost than a comparable cryogenic plant at feed gas capacities below about 40×10^6 SCFD. The cost trend, if extrapolated, would appear to show that cryogenic processing is more economical at the flow rates ($80-100 \times 10^6$ SCFD) used in this report. The standard lean oil absorption process[31] studied indicated a gas cost considerably higher than either the cryogenic or PSA process. Further research on either process does not appear highly attractive at this time.

One novel process is based on the fact that methane will selectively form solid hydrates at high pressure and low temperature[38]. The separated hydrate is easily decomposed by heating and enriched methane is recovered. This process is attractive since the reactions occur at high pressure and recompression is not needed. Also, relatively little energy is needed to break the hydrate. Equilibrium and kinetic data are needed and are being pursued by GRI. A pilot scale unit is needed to study the physical handling (pumping and separation) of the hydrate.

One disadvantage common to several nitrogen removal processes is that it is the major component, methane, which must be handled in bulk. Economics are likely to improve if the minor component, nitrogen, can be absorbed, adsorbed, etc. Carbon molecular sieves of a different type, narrow pore, have some capability in this respect[38] and should be investigated more thoroughly. Literature searches should be made and followed by laboratory testing to identify items such as a solvent which selectively absorbs nitrogen. Other desirable materials would include a solid sorbent for nitrogen and a membrane which preferentially permeates nitrogen.

6.3 Direct Use in Power Generation

The high CO_2 and/or N_2 content, and resultant lower heating value, of most LQNG would pose little problem for use in electricity generation. Nearly all of the LQNG is in the heating value range acceptable for use in gas turbines and could also be used in cofiring applications. However, it is not current practice to transport LQNG through the commercial pipeline network except when blended with other higher Btu gases to achieve a blended product within the accepted range of "pipeline quality."

This analysis has shown that, if sufficient volumes of LQNG were available to be transported through the pipeline network and access could be gained, then it might be more economical to transport high nitrogen LQNG and use it for direct combustion for power generation than to upgrade it to pipeline quality. The key questions for this option that require more detailed investigation are to determine (1) if there are sufficient reserves of high N_2 LQNG in a producing area, (2) if access could be gained to the pipeline network without a significant added tariff for "batching through" the LQNG, and (3) if there would be any problem in providing gas storage at the power plant site. An affirmative answer to these questions could make utility power generation a viable and economic option.

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APPENDIX A

THE LOW-QUALITY NATURAL GAS RESOURCE

Appendix A

THE LOW-QUALITY NATURAL GAS RESOURCE

This appendix briefly summarizes work done to date to assess the Low Quality Natural Gas resource base in the U. S. Recent efforts, mainly fostered by the Gas Research Institute (GRI), have brought together and updated existing gas reserve figures and gas composition data from various sources to compile a rather complete data base on the quantities of LQNG found in the lower-48 states.

This followed an earlier study in which E. J. Hoffman surveyed the occurrence of subquality natural gas in the U. S. and concluded that substantial quantities exist[42]. Gas compositions from many of the sources were such that some degree of processing would be required to bring their production up to pipeline specifications.

A recently completed project by Energy and Environmental Analysis Inc. for the GRI has provided a more comprehensive, quantitative data base for gas compositions and volume of resource in over 600 basin/formation categories in the lower-48 states[1]. This study integrated gas composition data from several major data bases that were available with corresponding reserves estimates and production data. It also included economic data which were assembled to provide estimates of wellhead resource costs. This data base is now available on disks for use with personal computers as well as in hard copy. A summary report is available. The following material is mainly a synopsis of the GRI/EEA account of the extent and distribution of U. S. low- and high-quality natural gas sources.

A.1 Production of LQNG

The quantities of LQNG being actually produced are based on 1988 production figures, the most recent annual data available at the time of the study. The cut-off criteria distinguishing Low- from High quality gas were taken to be: sub-quality when more than 2% carbon dioxide or more than 4% nitrogen or more than 4% of these combined. Almost 27% of the total gas production in the contiguous 48 states was sub-quality by these standards. Data on hydrogen sulfide content were not comprehensive or accurate enough to permit such a detailed breakdown for that contaminant. Consequently, H_2S is discussed separately below.

The annual production of LQNG broken down by region is shown in Table A-1, rearranged from Reference 1. A map of the regions used in the study, from the GRI "Hydrocarbon Model", is also given with the Table. The five regions producing the largest amounts of LQNG cover the western plains and the eastern slopes of the Rockies from Montana to Texas and from Arizona to Louisiana. These areas produced 2,968 BCF of LQNG in 1988, or 76% of the total subquality gas produced nationally. These data do not include a number of special reservoirs, primarily in the Rocky Mountain states, which produce practically pure carbon dioxide. The offshore regions, the Eastern states and southern Louisiana produce practically no subquality gas. Although they produce relatively smaller amounts, the remaining areas of the country all yield more than half of their total production as LQNG.

If one considers only onshore production, the annual totals for all the lower-48 states were 3,888 Bcf of low-quality and 6,446 Bcf of high-quality gas. Thus, low-quality gas comprised almost 38% of the on-shore, non-associated natural gas produced.

A.2 LQNG Reserves

The proven reserves of raw natural gas compiled in this study total just under 144 Tcf. Of this, the reserves that were considered to be subquality amounted to nearly 49 Tcf, or 34% of all nonassociated gas reserves. Most of the LQNG is either high in nitrogen or high in carbon dioxide; relatively little is high in both. Reserves were classified as:

	% of Total Gas Reserves
LQNG with Only Excessive CO_2	17
LQNG with Only Excessive N_2	13
LQNG with Both High CO_2 and High N_2	4
Total LQNG	34
High Quality Gas	66
Total Reserves	100

Hydrogen sulfide often occurs with the high CO_2 gas; we discuss it separately in a following section. Table A-2 ranks the reserves of LQNG in each of the same fourteen regions covered in Table A-1.

It may be noted that proven reserves are defined as known sources that are estimated to be producible in future years under existing operating conditions and economics.

As indicated in Table A-2, the mid-continent region contains over one-third of all the LQNG reserves in the contiguous states. This region together with the adjacent Foreland Province and the Arkla-East Texas regions account for two-thirds of the total. High nitrogen fields are frequent in the mid-continent; helium is also often associated with these sources.

The Gulf of Mexico also holds substantial reserves of LQNG. Even though there is a relatively low proportion of low-quality gas offshore, the total resource is so large that it constitutes a significant reserve of LQNG. Most of the LQNG in the Gulf is in the Norphlet area where CO_2 and H_2S are common, and where not much is being produced. As such, this area is noted in Section A.4 below as one of the presently known but unexploited sources of LQNG.

The Permian Basin in west Texas has occurrences of high CO_2 and H_2S. Including the Permian and rest of Texas with the regions previously mentioned (altogether regions FR, JN, JS, D, G, and EGO) comprises an area covering the middle of the continent that holds 91% of all the LQNG reserves.

In the west, the Sacramento Basin in California contains fields contaminated only with nitrogen. The only subquality reserves in the Eastern region are in an area of West Virginia that is high in carbon dioxide.

A.3 Future LQNG Potential

The EEA study produced the following estimates for future additions to the reserves of all natural gas in the contiguous states through appreciation of the reserves in known reservoirs as well as through the discovery of new fields:

Appreciation in Existing Fields	184 Tcf
New Discoveries of Conventional Fields	391 Tcf
Coalbed Methane	24 Tcf
Total Gas Reserves Appreciation	599 Tcf

The first category, existing fields, included western tight gas and eastern Devonian shale gas sources.

The proportion of sub-quality gas in future additions or discoveries was based on the composition of known, correlated sources. Consequently the quantity of LQNG in the added reserves could be estimated at 222 Tcf, or 37% of the total expected appreciation. Table A-3 lists the regions ranked according to the estimated potential additions of subquality gas reserves. The prominent region in this case is the Foreland Province, the central Rocky Mountain states, which is estimated to contain more than one third of the total reserves appreciation. The Table also shows that two other areas that may emerge as important producers of LQNG are the Midwest and the Thrust Belt.

A.4 Occurrence of Hydrogen Sulfide

Available gas composition data was such that the study was able to classify the resources at the formation level only into those which are "H_2S-prone" and those which are not. The study recognized that this was not a very accurate measure of hydrogen sulfide occurrence because some fields in the H_2S-prone formations, in fact, produce sweet gas while some in the non-H_2S-prone formations produce sour gas. Nevertheless, this procedure was believed to provide the best estimate of overall H_2S-contaminated gas reserves that could be made from these data. The admitted overestimate in the H_2S-prone regions was thought to be approximately offset by the underestimate in the remainder of the resource.

Thirty-one formations were identified as "H_2S-prone". These occur in 9 out of the 14 regions discussed above. They comprise a total of 19.4 Tcf of gas likely to be contaminated with significant amounts of hydrogen sulfide. This amounts to 13.5% of the entire proved reserves of natural gas in the lower-48 states.

Table A-4, following, ranks the producing regions according to the total of the known reserves in the H_2S-prone formations in the region. Only nine of the regions appear in this list. The five that contain no major H_2S-prone plays are the Eastern region, the Williston Basin, South Louisiana and the Pacific Onshore and Offshore regions.

A.5 Known LQNG Sources Not Being Produced

Not enough data was compiled in the EEA study to produce an exhaustive list of all the fields that are shut-in or undeveloped on account of the gas being excessively low in quality and uneconomic to produce. However, on the larger scale, they were able to identify several relatively large reservoirs that fall in this category. The information available about many of these is somewhat incomplete because, as would be expected, few additional exploratory wells are drilled in such zones once they have been discovered to produce subquality gas.

Many of these reservoirs are known because they are stratigraphically below or adjacent to currently producing fields. The major component in many of these reservoirs is carbon dioxide. Some, for example in the Permian Basin, are situated between areas that produce nearly pure hydrocarbons and those that produce nearly pure CO_2 so that they exhibit a geographical trend from one composition to the other.

Following is a list of ten known reservoirs which are believed to contain major deposits of LQNG and which are described in more detail in the GRI/EEA report. The Moxa Arch, listed first because it may be the largest of these sources, is estimated to contain at least 128 TCF if high-CO_2 gas. Less than 2% of this area has been developed, and currently producing wells average 22% hydrocarbons, 66% CO_2, 7% N_2, 4.5% H_2S and 0.5% He. The undeveloped area is thought to be lower in hydrocarbons so that the estimated reserve of methane in this reservoirs comes to 9 Tcf. The other reservoirs in this list are thought to be smaller, but the extent of some is not well known.

Northern Moxa Arch, southwest Wyoming
Church Buttes Area, southwest Wyoming
Madden Deep Area, central Wyoming
Kevin-Sunburst Dome, northwest Montana
Wasatch Plateau, eastern Utah
Jackson Dome, south central Mississippi
Smackover Trend, southwest Arkansas
Sacramento Basin, California
Los Animas Arch, southeast Colorado
Permian Basin, west Texas

Seven of these reservoirs are in the mountain states: Montana, Wyoming, Utah, Colorado and west Texas. Two are in the Arkansas/-Mississippi region. The one in the west is in central California.

TABLE A-1

ANNUAL PRODUCTION* OF LOW- AND HIGH-QUALITY GAS

Region (see Fig. A-1)	Low-Qual Produced, BCF/yr	High-Qual Produced, BCF/yr	Total BCF/yr	LQNG, % of Production
1. Mid-continent (JN)	1,177	1,669	2,846	41.4
2. Arkla & East Texas (D)	691	407	1,098	62.9
3. Texas & Gulf Coast (G)	631	1,497	2,128	29.7
4. Permian Basin (JS)	434	648	1,082	40.1
5. Foreland Province (FR)	385	586	971	39.6
6. Fla., Miss., Alabama (B)	255	100	355	71.8
7. Pacific Onshore (L)	133	15	148	89.9
8. Thrust Belt (TB)	99	13	112	88.4
9. Midwest (C)	35	41	76	46.1
10. Williston Basin (WL)	24	18	42	57.1
11. South Louisiana (E)	15	964	977	1.5
12. Eastern U.S. (A)	8	489	497	1.6
13. Eastern Gulf of Mexico (EGO)	6	4,326	4,332	0.1
14. Pacific Offshore (LO)	0	36	36	0.0
Total U.S. (lower-48)	3,894	10,808	14,702	26.5

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* Statistics for nonassociated raw gas produced in the lower-48 states rearranged from P. H. Hugman, et al.[1]; regions ranked by volume of low-quality gas produced in 1988.

Figure A-1

MAP OF REGIONS REFERENCED IN TABLES A-1 to A-3

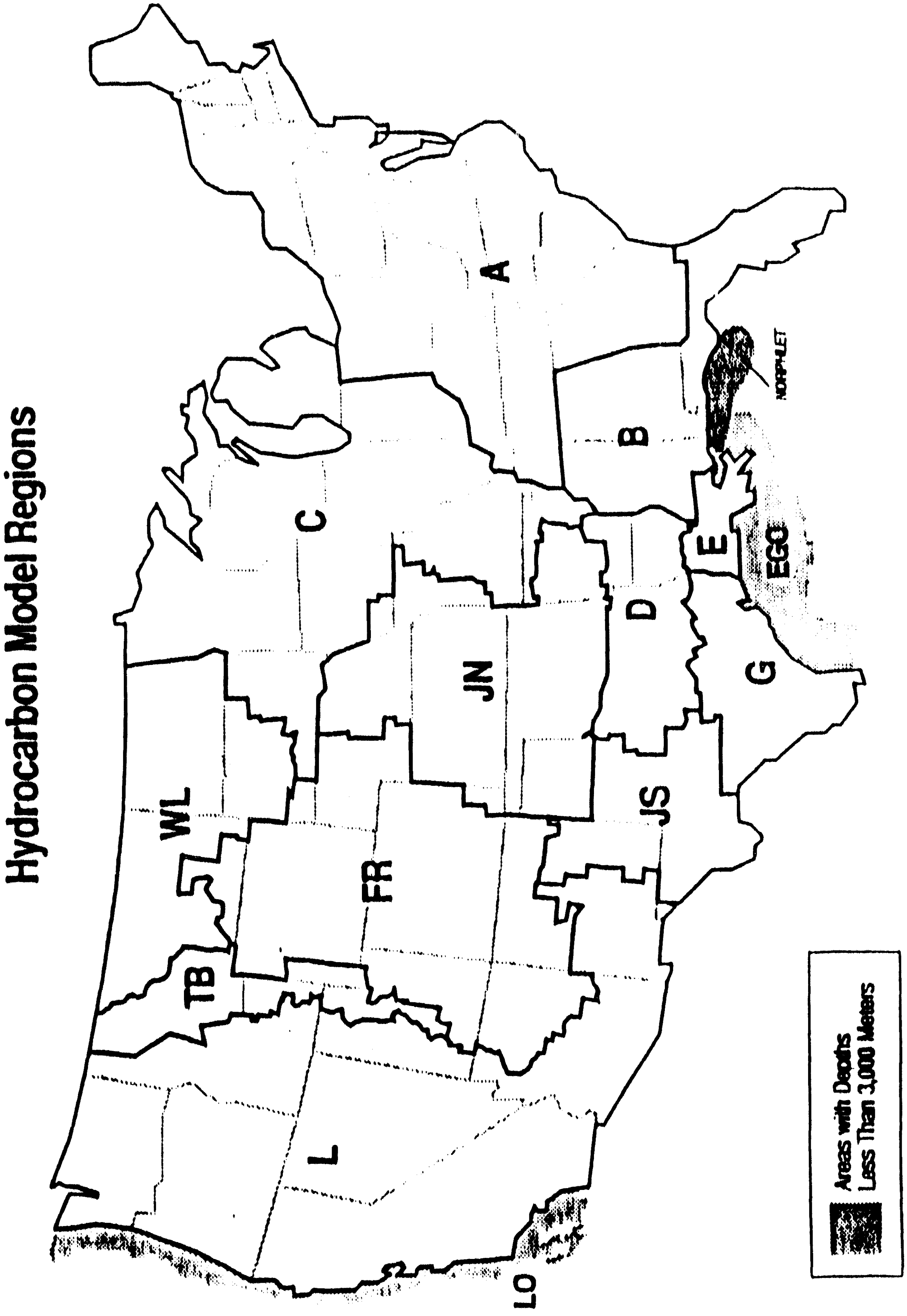

TABLE A-2

RESERVES* OF LOW- AND HIGH-QUALITY GAS

Region (see Fig. A-1)	Low-Qual Reserves, BCF	High-Qual Reserves, BCF	Total BCF	LQNG, % of Reserves
1. Mid-continent (JN)	17,451	16,775	34,226	51.0
2. Foreland Province (FR)	9,025	20,000	29,025	31.1
3. Arkla & East Texas (D)	6,266	3,807	10,073	62.2
4. Gulf of Mexico (EGO)	4,990	22,906	27,896	17.9
5. Permian Basin (JS)	3,512	6020	9,532	36.8
6. Texas & Gulf Coast (G)	3,275	8,642	11,917	27.5
7. Fla., Miss., Alabama (B)	1,503	672	2,175	69.1
8. Pacific Onshore (L)	945	130	1,075	87.9
9. Thrust Belt (TB)	811	713	1,524	53.2
10. Midwest (C)	439	504	943	46.6
11. Williston Basin (WL)	415	317	732	56.7
12. Eastern U.S. (A)	126	6,508	6,634	1.9
13. South Louisiana (E)	105	7,534	7,639	1.4
14. Pacific Offshore (LO)	0	565	565	0.0
Total U.S. (lower-48)	48,862	95,095	143,957	33.9

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* Statistics for nonassociated raw gas in the lower-48 states from P. H. Hugman, et al.[1]; regions ranked by 1988 estimates of volume of subquality reserves.

TABLE A-3

NEW FIELD AND RESERVES APPRECIATION POTENTIAL

Region* (see Fig. A-1)	Low-Qual. Potential TCF	High-Qual. Potential TCF	Total TCF	% of LQ Potential in Region
1. Foreland Province (FR)	77.0	31.2	108.2	34.6
2. Midwest (C)	33.0	1.5	34.6	14.8
3. Gulf of Mexico (EGO)	26.3	111.6	137.9	11.8
4. Thrust Belt (TB)	17.8	6.3	24.1	8.0
5. Arkla & East Texas (D)	16.5	7.2	23.7	7.4
6. Texas & Gulf Coast (G)	12.7	33.5	46.2	5.7
7. Mid-continent (JN)	11.4	57.1	68.5	5.1
8. Fla., Miss., Alabama (B)	9.0	7.1	16.1	4.0
9. Permian Basin (JS)	8.5	24.4	32.9	3.8
10. Pacific Onshore (L)	4.4	4.1	8.5	2.0
11. Eastern U.S. (A)	3.2	71.3	74.5	1.4
12. Williston Basin (WL)	2.5	0.9	3.4	1.1
13. South Louisiana (E)	0.2	16.7	16.9	0.1
14. Pacific Offshore (LO)	0.0	3.9	3.9	0.0
Total U.S. (lower 48)	222.5**	376.9	599.4	

---

* Regions ranked by estimates of future, subquality gas potential; 1988 nonassociated raw gas reserves from Reference 1.

** 37.1% of total reserves.

TABLE A-4

ESTIMATED RESERVES OF HYDROGEN SULFIDE-PRONE GAS

Region* (see Fig. A-1)	H_2S-Prone Reserves TCF
1. Gulf of Mexico (EGO)	4.98
2. Permian Basin (JS)	4.67
3. Arkla & East Texas (D)	3.52
4. Foreland Province (FR)	2.78
5. Mid-continent (JN)	1.11
6. Thrust Belt (TB)	0.83
7. Fla., Miss., Alabama (B)	0.56
8. Midwest (C)	0.50
9. Texas & Gulf Coast (G)	0.42
Total H_2S-prone**	19.37

---

* Regions ranked by reserves that occur in formations likely to produce appreciable levels of hydrogen sulfide; 1988 nonassociated raw gas reserves from Reference 1.

** 13.5% of total reserves.

APPENDIX B

METHODOLOGY FOR CALCULATING THE REQUIRED PRICE OF GAS

Appendix B

METHODOLOGY FOR CALCULATING THE REQUIRED PRICE OF GAS

A procedure has been developed to calculate the price of gas required to make investment in upgrading facilities viable for the gas producer/processor who has discovered reserves of LQNG. The calculation procedure has been adapted from a GRI economic analysis procedure[10], and much of the nomenclature has been retained in order that the procedure described here can be related to the GRI report.

The required price of gas is determined by summing the annual equivalents of the present worths of the following items, expressed in terms of a unit of product:

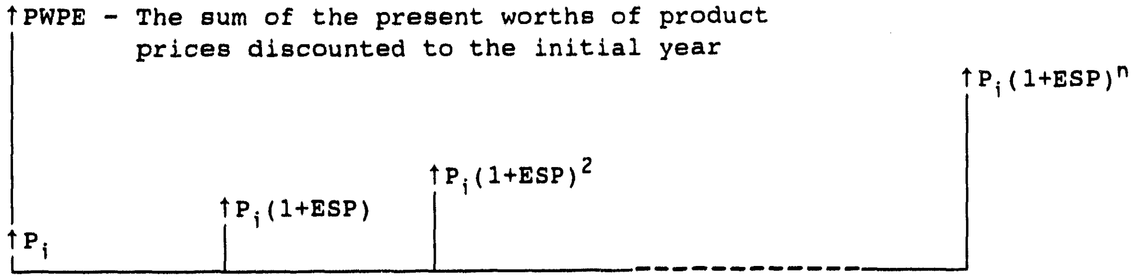
a. Cost of Process Facility, including Return
b. Operating and Maintenance Cost
c. Feedstock Cost
d. Cost of Working Capital

The sum of these items is set equal to the annualized present worth of the revenue from the sale of a unit of product, as shown in the following equation:

$$CPF + OMC + FC + CWC = RPS$$

The revenue from sales is a function of the price of pipeline quality gas at the time of unit start-up and the way that price grows over time. In the calculation routine gas price is projected to grow at a constant rate and that estimate of price growth is entered as a percent of the inflation rate.

An example of the calculation procedure is presented in Table B-2. On the third page of this example, calculations are detailed for handling price growth and determining the impact on the required selling price of gas in the initial year. Price growth is input as PPGWR; in the example it is 200% of the rate of inflation. The annual growth rate of product price (ESP) is the inflation rate (INF) times the product price growth (PPGWR) divided by 100. The price in each year is diagramed in the following figure.



For price increasing at a constant growth rate, a term TVPE replaces the discount rate in the usual present value formula; thus:

$$\text{PWPE} = \text{PW(YRS,TVPE)} = \frac{(1 + \text{TVPE})^{\text{YRS}} - 1}{\text{TVPE}*(1 + \text{TVPE})^{\text{YRS}}}$$

and $$\text{TVPE} = \frac{\text{CDD} - \text{ESP}}{1 + \text{ESP}}$$

where CDD is the current dollar discount rate. Similar formulas account for growth in operating cost, feed stock cost, and cost of working capital over time.

All of the costs and revenues are brought to their present worths in the initial year and then the annual equivalent of each cost is calculated by multiplying it by an annualization factor, ANBL. In the example the annualizing factor is expressed in constant dollar terms. This was done because the set of calculations in the GRI reference document were done in constant dollars and because many of the forcasts of gas price growth are given in constant dollar terms. The answer for the price of gas in the initial year will be the same regardless of whether you work in constant or current dollars. The ANBL terms appear in all the individual elements. It is important to note that working in constant dollars does yield a value of CCR, the capital charge factor, that is lower than expected by those who are attuned to analyzing in a current dollar framework.

Data input to run the calculation program appears on pages 1 and 3 of the example output. On page 1 results of the cost estimating work is input in the upper box. The calculation of total plant cost and variable operating and maintenance cost follows the procedure outlined in the EPRI "TAG." The percent cost factors on pages 1 and 2 were not changed throughout the set of runs made for this study. However, they can be changed at the users discretion. The result of the calculations on page 1 is the total plant investment (TPI) for the gas upgrading plant. On page 2 the variable operating and maintenance cost (VOM), the feedstock cost (FC), and the working capital cost (WC) for the initial year of operation are calculated.

On page 3 of the sample calculation, the economic analysis of the project is performed to calculate the price of gas that is required to provide the return on investment commensurate with the inputs on discount rate, life, and financing assumptions. Definitions for the variables in the formulas in the example calculation are given in Table B-1. METC has been provided with a copy of the calculation routine used to produce the example calculation. This routine is a spreadsheet file that will work with either Lotus 1-2-3 (file extension .WK1) or Quatro Pro (file extension .WQ1).

Table B-1

DEFINITION OF TERMS

AFDUC - Allowance for Funds DUring Construction represents interest costs

Ann(t,d) - Annualized value of a present worth over t years at a discount rate of d (equal to 1/PW(t,d))

ATCOC - weighted average After Tax Cost Of Capital, based on funding from equity and debt

BPR - Base Product Revenue is the revenue from the sale of a unit of product in the first year of operation, i.e. the product price

CCR - Capital Charge Rate, which relates the unit capital investment to the annualized value of operating costs and revenues (in this case the CCR is on a constant $ basis)

CDD - Current Dollar Discount factor

CYR - Construction period in YeaRs during which investment $'s are expended

ESO - EScalation factor for Operating and maintenance cost

ESP - annual EScalation factor for Product price

FCD - Fraction of investment Capital from Debt sources

FCE - Fraction of investment Capital from Equity sources

FCGWR - constant annual Feed Cost GroWth Rate stated as % of INFlation rate

FDC - FeeD Cost in initial year, treated separately from other operating cost to allow for differences in cost escalation rates

INF - general rate of INFlation

KDD - Konstant Dollar Discount rate

PPGWR - constant annual Product Price GroWth Rate stated as % of INFlation rate

Table B-1 (cont.)

PW(t,d) - uniform series Present Worth factor for t years at discount rate d

SPI - Specific Plant Investment is the cost of investment per unit of production capacity. It is the Total Plant Investment divived by the Design Capacity times the Stream Factor.

TOPC - Total OPerating Cost is the sum of the annualized present worths of the operating & maintenance costs, the feed cost and the cost of working capital

TVOME - Time Value of Operating & Maintenance cost Price Escalation relative to the discount factor CDD, when the O&M cost is increasing at a constant rate of growth then TVOME replaces the d discount in the PW(t,d) relationship

TVPE - Time Value of product Price Escalation relative to the discount factor CDD when the product price is increasing at a constant rate of growth, TVPE replaces the d discount in the PW(t,d) relationship.

TYR - Tax life in YeaRs over which investment is depreciated

YRS - operating life of the investment in YeaRS

GAS TREATING PLANT Table B-2

CASE: Cryogenic Nitrogen Removal Feed Gas: 6% N2 GAS

CASE CODE: 6NC

Page 1 -- Calculate Total Plant Investment Cost

INPUTS FROM COST ESTIMATION

Design Cap(mmscf/d PLG)	DC	84.7
Service Factor	SF	0.9
Process Field Cost(MM$)	PFC	11.28
Utilities Field Cost(MM$)	UFC	1.213
Operators/Shift	OPS	3.0
Cat & \Chemicals(M$/Yr)	CAC	0
Makeup Water(mGal/min)	MUW	0
Feed Gas($/mscf)	FGS	0.116
Feed Gas(mmscf/d)	FG	88.2

TOTAL PLANT COST	COST FACTOR %		COST, K$ W/O CONT
PROCESS			
Field Cost Direct and Indirect		PFC	11.3
Sales Tax %	4		0.5
			======
Basic Facility Construction Investment		BFCI	11.7
Project Contingency % of BFCI	15	PC	1.8
Process Design Allowance % of BFCI	0		0.0
			======
			13.5
Home Office % of BFCI+PC+PDA	6		0.8
Engineering % of BFCI+PC+PDA	6		0.8
			======
Total Process Facilities Construction Invstment		TPFCI	15.1
OFFSITES/UTILITIES: DIRECT AND INDIRECT			
Field Cost, Direct and Indirect			
a) Utilities		UFC	1.2
b) Gen Facilities % of Process BFCI	20		2.3
			======
			3.6
Sales Tax % of Field Cost	4		0.1
			======
BFCI Offsites			3.7
Project Contingency % of BFCI Offsites	15		0.6
			======
BFCI Offsites + Proj. Contingency			4.3
Home Office % of Offsites BFCI+PC	6		0.3
Engineering % of Offsites BFCI+PC	6		0.3
			======
		TOFCI	4.8
Total Facilities Constrctn Invst(TPFCI+TOFCI)		TFCI	19.9
TOTAL PLANT INVESTMENT(TPI)			
Total Facilities Constrctn Invst			19.9
Initial Fills % of TFCI	0.8		0.2
Startup % of Ann Opr Cost(AOC)	20		1.3
Prepaid Royalties % of TCFI	0.5		0.1
			======
Total Plant Investment		TPI	21.4

GAS TREATING PLANT Table B-2 (cont.) Page 2

CASE: Cryogenic Nitrogen Removal Feed Gas: 6% N2 GAS

CASE CODE: 6NC

Page 2 - Calculate Operating & Maintenance Cost

VARIABLE OPR & MAIN COST(MM$/YR)	DATA INPUTS Estimate	 % Fact.		
TOTAL MAINTENANCE COST				
Process % of TPFCI		4		0.6
Offsites % of TOFCI		2		0.1
				======
			TMC	0.7
DIRECT LABOR COST				
Shift Operators	3			
Annual Dir Lab @ $/Hr	20			0.5
Maintenance Lab(% TMC)		60		0.4
				======
Total Direct Labor			TDL	0.9
Labor Overheads				
Supervision % of TDL		25		0.2
Benefits % of TDL		25		0.2
Gen & Clerical % of TDL		45		0.4
Corporate OH % of TDL		30		0.3
Supplies % of TDL		5		0.0
				======
Total Labor Overheads				1.2
Catalyst & Chemicals MM$				0.0
Utilities				
Imported Power, Gas, Steam	0			0.0
Makeup Water MGal/Min(MUW)	0			
Water Cost $/MGal	0.0125			0.0
Maintenance Materials % of TMC		40		0.3
Local Taxes & Ins % of TFCI		1.5		0.3
				======
Total Other O&M				0.6
Var Opr & Main(DL+Lab OH+Oth O&M)			VOM	2.8
Feed Gas mmscf/d	88.2			
Trt Cost(Est in $/mscf)	0.116		FC	3.7
				======
Ann Opr Cost YR 1(VOM+FC)			AOC	6.5
Working Cap(Consm & Parts)% of TFCI		1.4		0.0
Working Cap(Acct Rec)1 Mon of AOC				0.1
				======
			WC	0.1

Table B-2 (cont.)

CASE: Cryogenic Nitrogen Removal

Feed Gas: 6% N2 GAS

CONSTANT $ DISC	KDD	0.07	UNIT REVENUES AND COSTS FOR FIRST YEAR		
INFLATION	INF	0.05	BASE YR PROD REV	BPR	
FRAC CAP FROM EQ	FCE	0.8	SPC CAP COST(TPI/DC*SF)	SPI	0.770
FRAC CAP FROM DBT	FCD	0.2	O&M COST(Base Yr)	OMC	0.099
RETURN ON EQUITY	ROE	0.142	FEED COST(YR 1)	FDC	0.121
RETURN ON DEBT	ROD	0.09	WORKING CAPITAL(YR 1)	UWC	0.004
BOOK LIFE YRS	YRS	20	PD PRICE GW(% INF)	PPGWR	100
TAX LIFE	TYR	10	O&M COST GW(% INF)	OMGWR	100
TAX RATE	FIT	0.4	FEED COST GW(%INF)	FCGWR	100
CONSTRUCTN PERIOD	CYR	3	WORK CAP GW(% INF)	WCGWR	100
ALW FUND DUR CONST	AFDUC	0.11	Calculate		
ESCAL RATE CONST	ESC	0.05	ESCAL RATE PRODUCT	ESP	0.05
Calculate			ESCAL RATE FUEL	ESF	0.05
WT AVG AFT TAX COC	ATCOC		ESCAL RATE O&M	ESO	0.05
CURRENT $ DISC	CDD	0.1235			

ATCOC = +ROE*FCE+(1-FIT)*(ROD*FCD)	ATCOC	0.124
CDD = +(1+INF)*(1+KDD)-1	CDD	0.124
PW(YRS,CDD) = ((1+CDD)^YRS-1)/(CDD*(1+CDD)^YRS)	PWBL	7.309
Ann(YRS,KDD) = +(KDD*(1+KDD)^YRS)/((1+KDD)^YRS-1)	ANBL	0.094
ESP = +INF*(PPGWR/100)	ESP	0.050
TVPE = +(CDD-ESP)/(1+ESP)	TVPE	0.070
PW(YRS,TVPE) = ((1+TVPE)^YRS-1)/(TVPE*(1+TVPE)^YRS)	PWPE	10.594
ESO = +INF*(OMGWR/100)	ESO	0.050
TVOME = +(CDD-ESO)/(1+ESO)	TVOME	0.070
PW(YRS,TVOME) = ((1+TVOME)^YRS-1)/(TVOME*(1+TVOME)^YRS)	PWOME	10.594
ESF = +INF*(FCGWR/100)	ESF	0.050
TVFCE = +(CDD-ESF)/(1+ESF)	TVFCE	0.070
PW(YRS,TVFCE) = ((1+TVFCE)^YRS-1)/(TVFCE*(1+TVFCE)^YRS)	PWFDE	10.594
ESW = +INF*(WCGWR/100)	ESW	0.050
TVWCE = +(CDD-ESW)/(1+ESW)	TVWCE	0.070
PW(YRS,TVWCE) = ((1+TVWCE)^YRS-1)/(TVWCE*(1+TVWCE)^YRS)	PWWCE	10.594
PW(TYR,CDD) = ((1+CDD)^TYR-1)/(CDD*(1+CDD)^TYR)	PWTL	5.570
EEL3 = +2*(TYR-PWTL)/(TYR*(TYR+1)*CDD)	EEL3	0.652
EEL1 = +(1+AFDUC)^(CYR/3)	EEL1	1.110
EEL2 = +FIT*(FCE+FCD*(1+AFDUC)^(CYR/3))	EEL2	0.409
EEL4 = +((PWBL/YRS)*(1-(ATCOC/CDD))+(ATCOC/CDD)*EEL3)	EEL4	0.654
CCR = +ANBL/(1-FIT)*(1/(1+ESC))^(CYR/3)*EEL1*((PWBL/YRS)*(1-ATCOC/CDD)+ATCOC/CDD)-EEL2*EEL4)	CCR	0.127
SPI*CCR = (BPR*ANBL*PWPE)-(OMC*ANBL*PWOME)-(FDC*ANBL*PWFDE)-(UWC*ANBL*PWWCE)		
Let TOPC = +[(OMC*ANBL*PWOME)+(FDC*ANBL*PWFDE)+(UWC*ANBL*PWWCE)]	TOPC	0.223
	SPI*CCR	0.098
BPR = +((SPI*CCR)+TOPC)/(ANBL*PWPE)	BPR	0.321

PRICE OF UPGRADED GAS PRODUCT IN INITIAL YEAR($/MSCF) = 0.321

APPENDIX C

PLOTS OF NATURAL GAS RESERVES VS. IMPURITIES CONTENT

Figure C-1

RESERVES OF NATURAL GAS VS. NITROGEN CONTENT

Lower 48 States

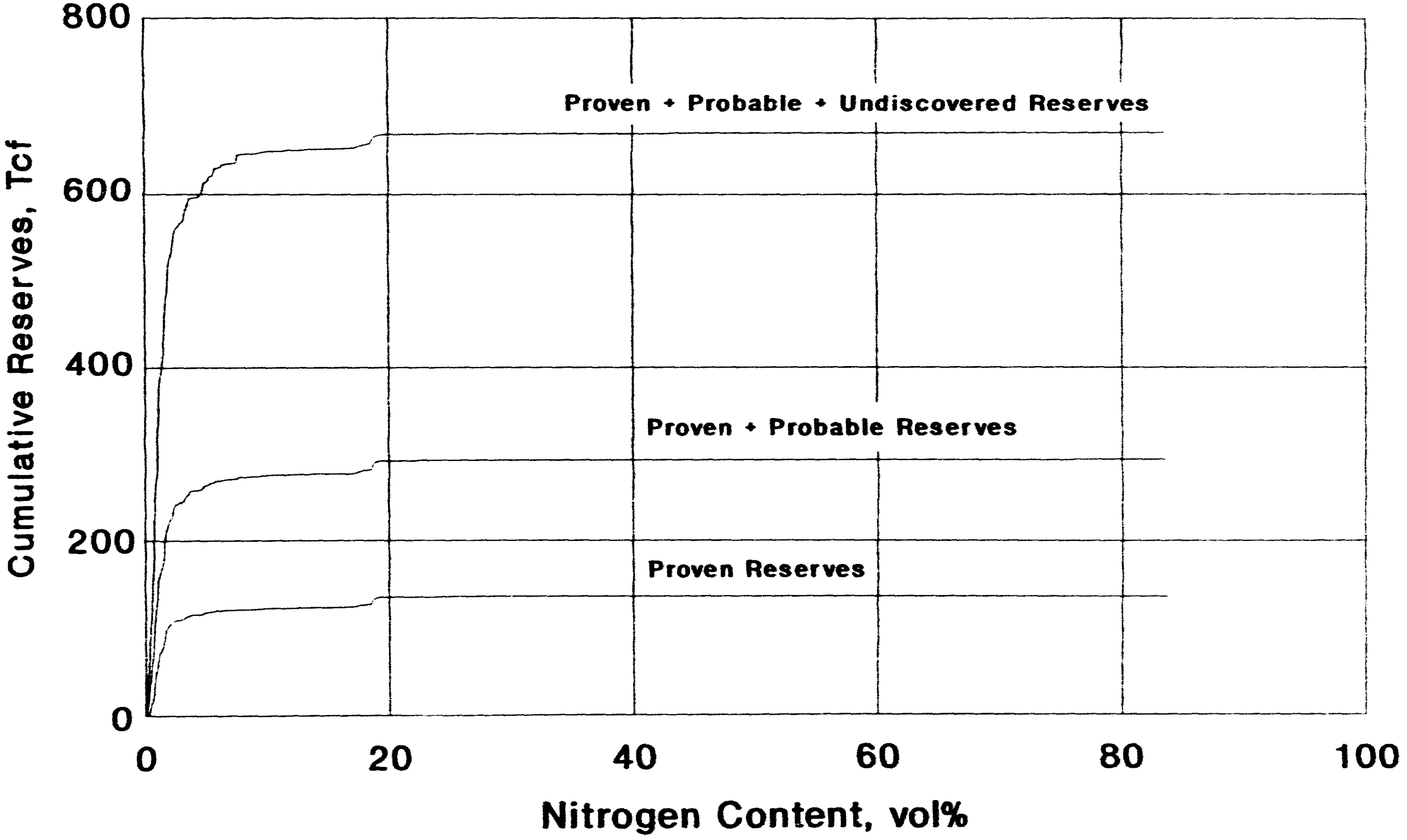


Figure C-2

RESERVES OF NATURAL GAS VS. CARBON DIOXIDE CONTENT

Lower 48 States

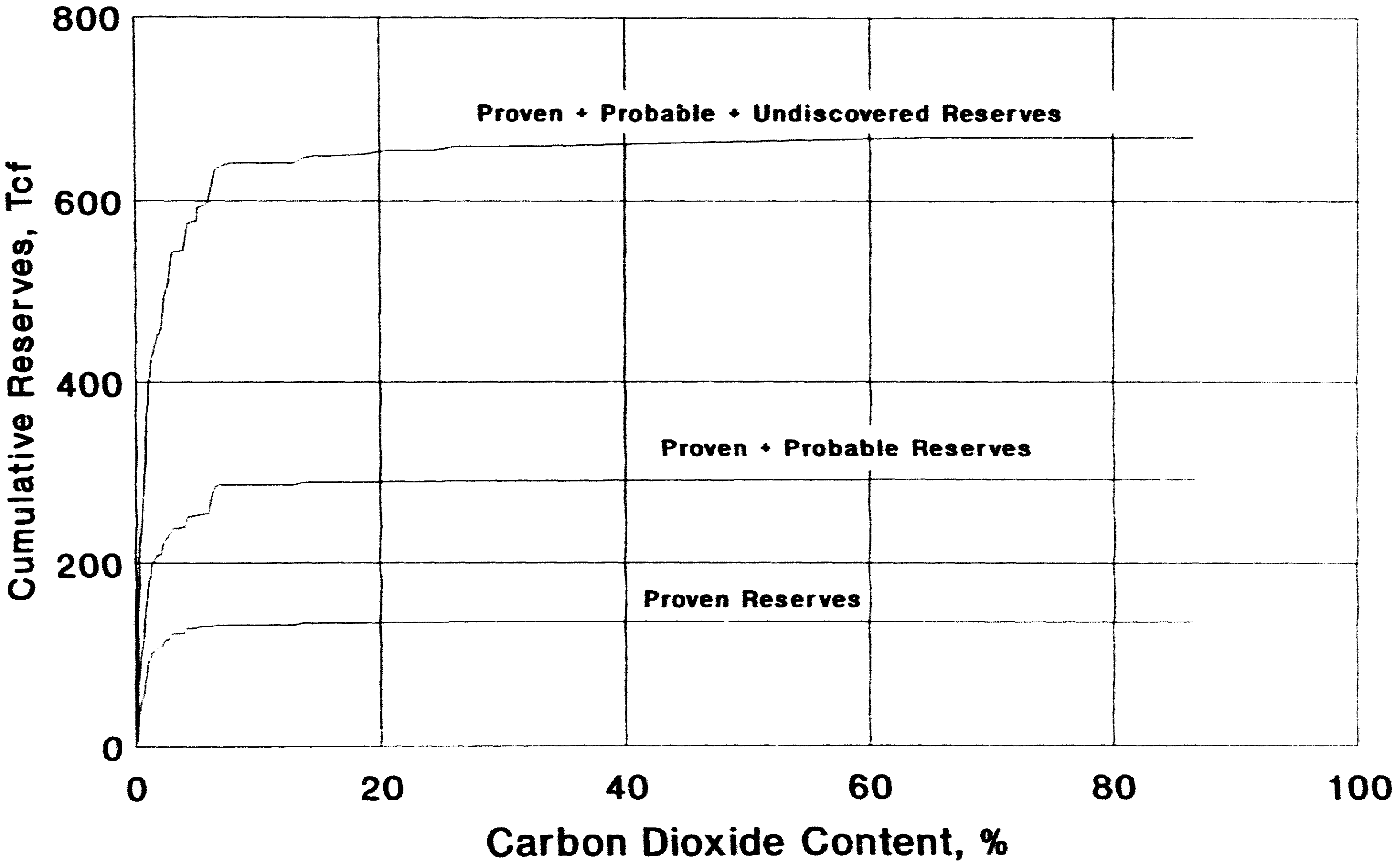


Figure C-3

RESERVES OF NATURAL GAS VS. NITROGEN PLUS CARBON DIOXIDE CONTENT

Lower 48 States

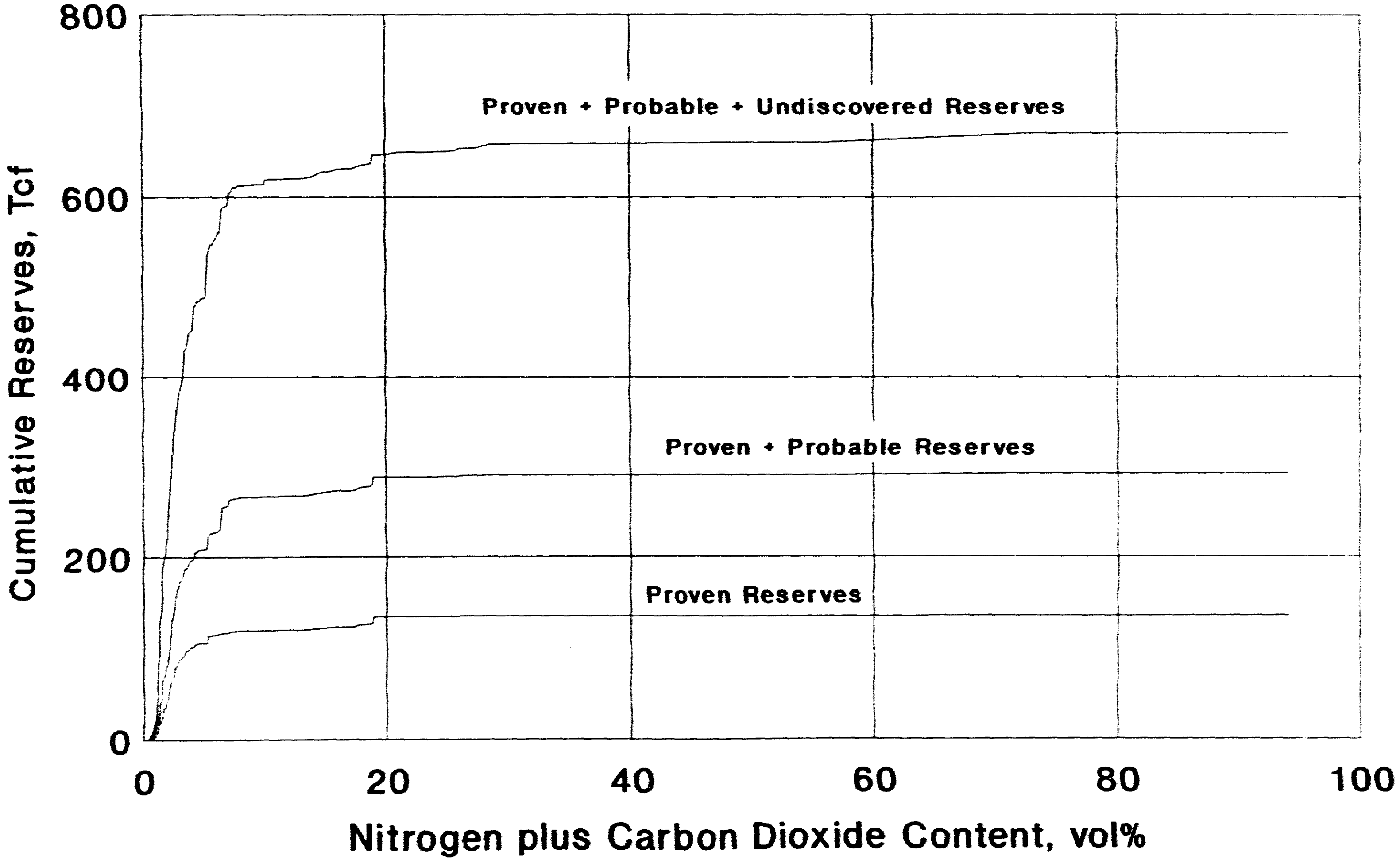


Figure C-4

PROVEN RESERVES VS. NITROGEN CONTENT

Lower 48 States

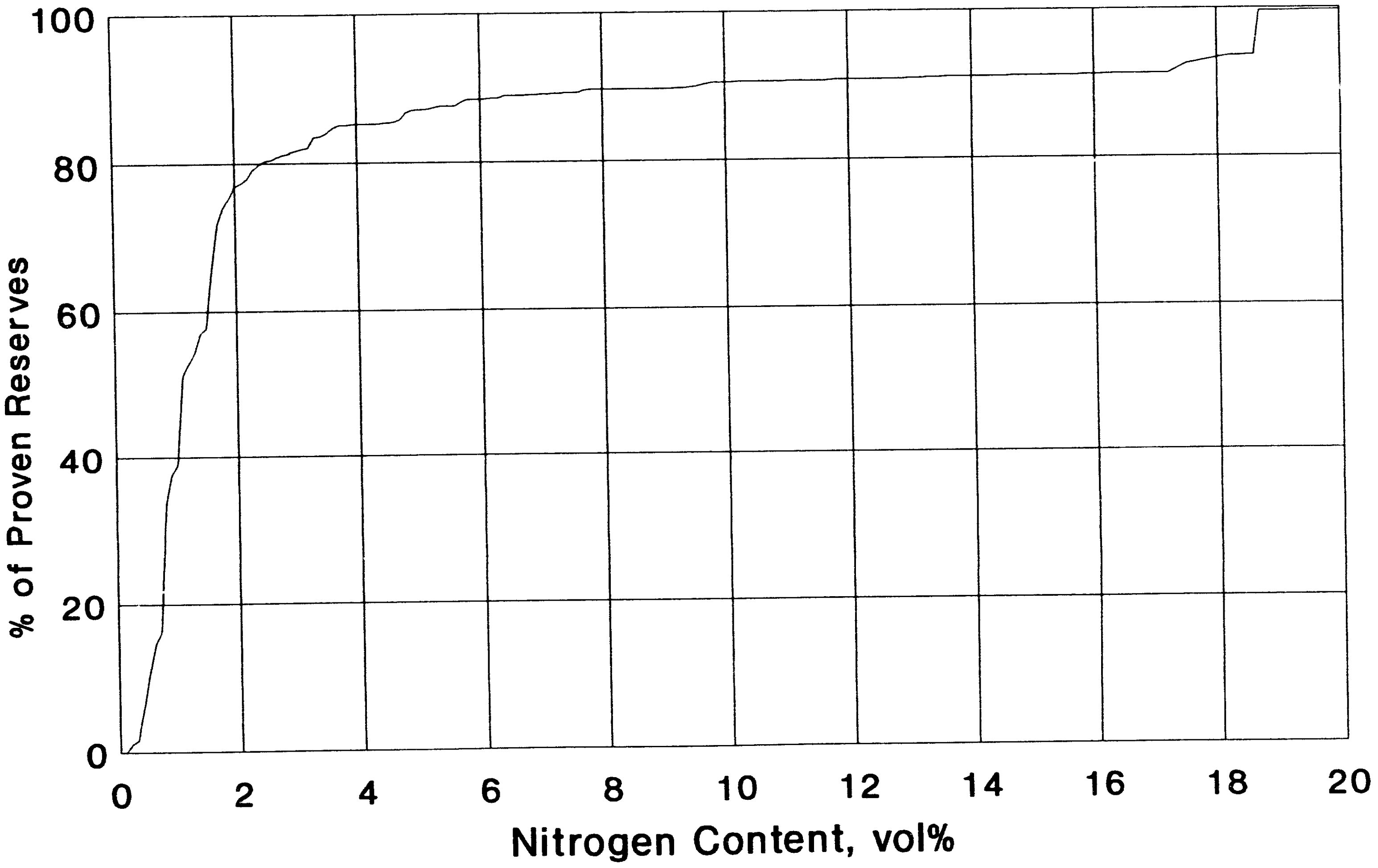


Figure C-5

PROBABLE RESERVES VS. NITROGEN CONTENT

Lower 48 States

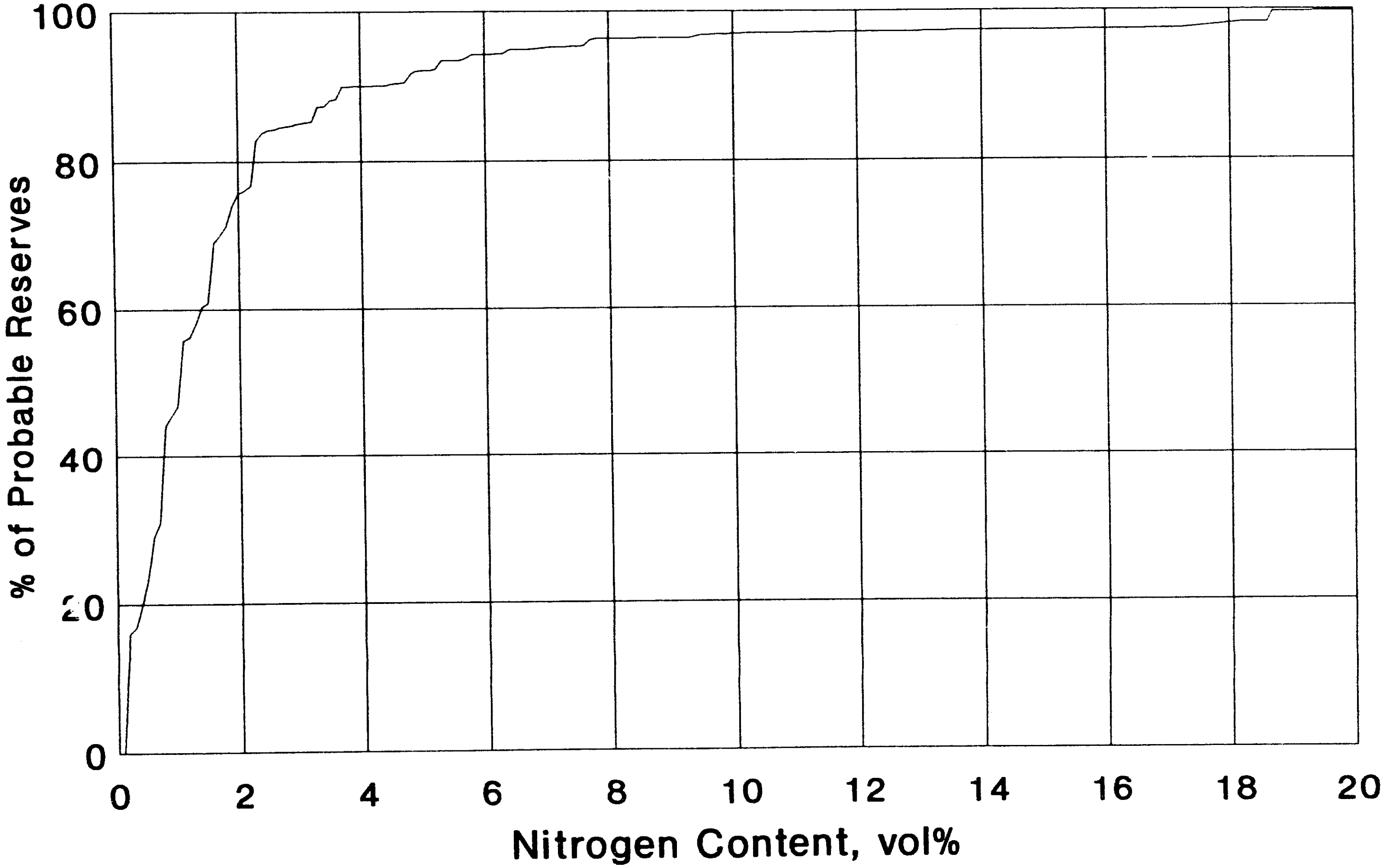


Figure C-6

PROVEN PLUS PROBABLE RESERVES VS. N_2 CONTENT

Lower 48 States

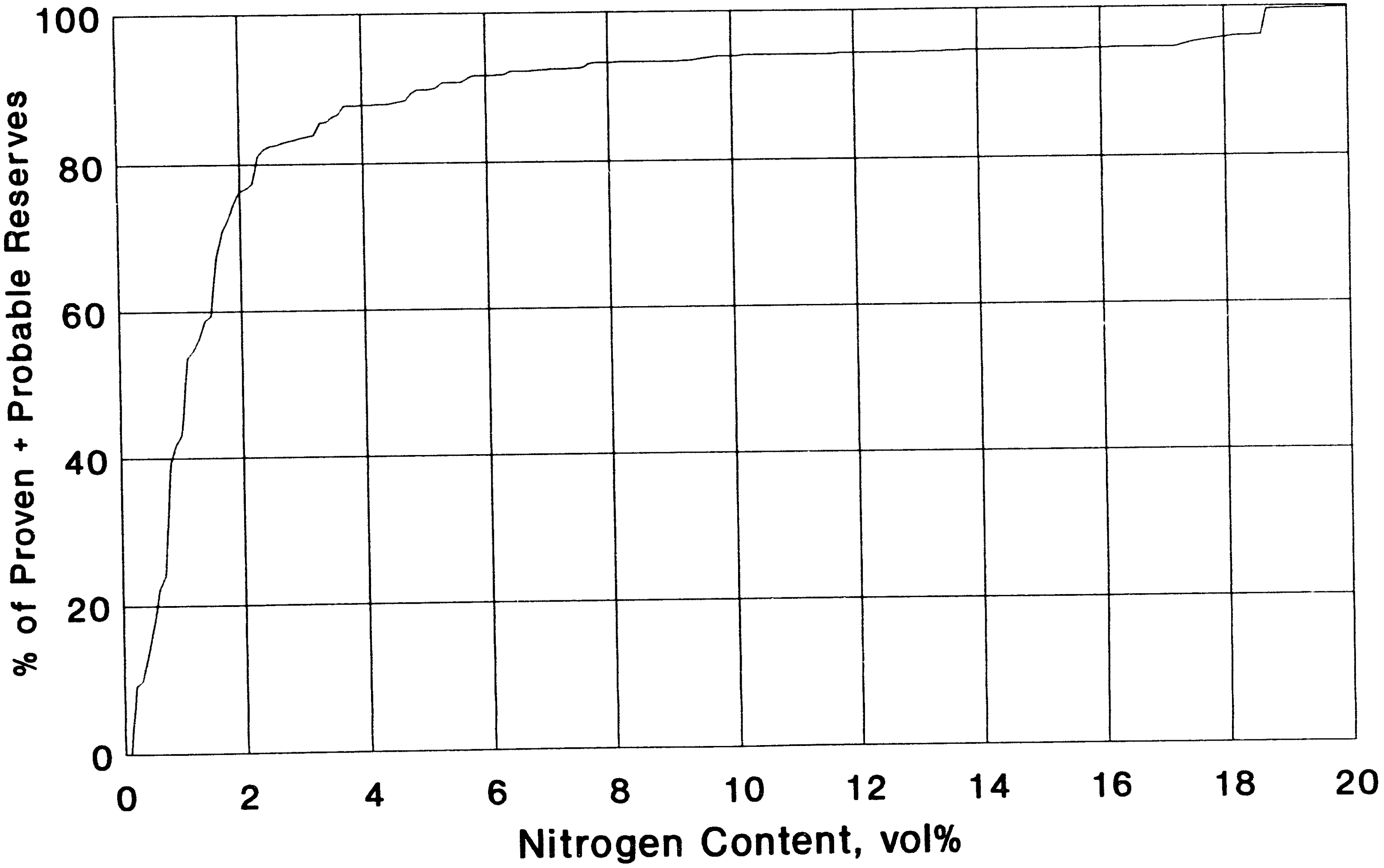


Figure C-7

UNDISCOVERED RESERVES VS. NITROGEN CONTENT

Lower 48 States

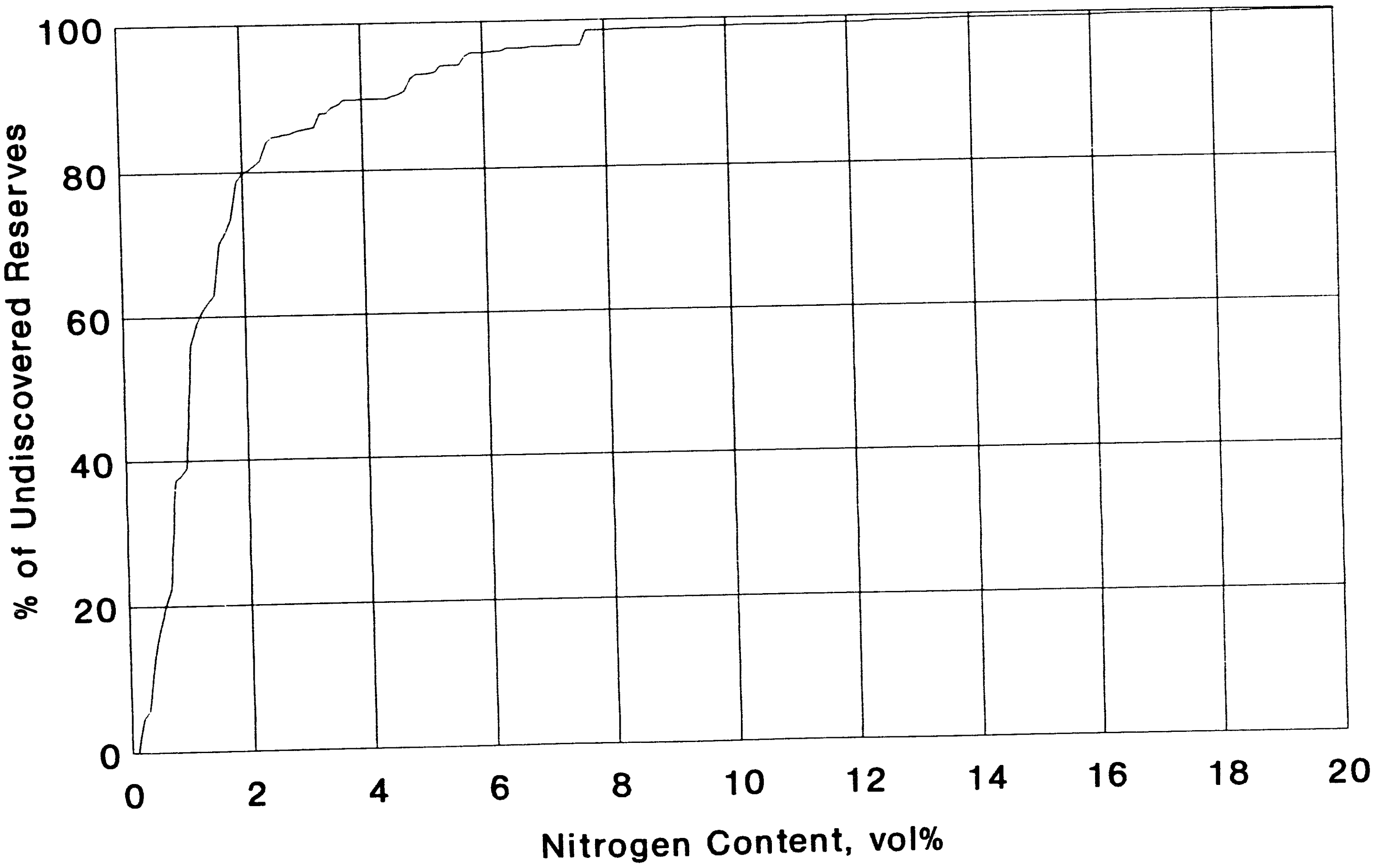
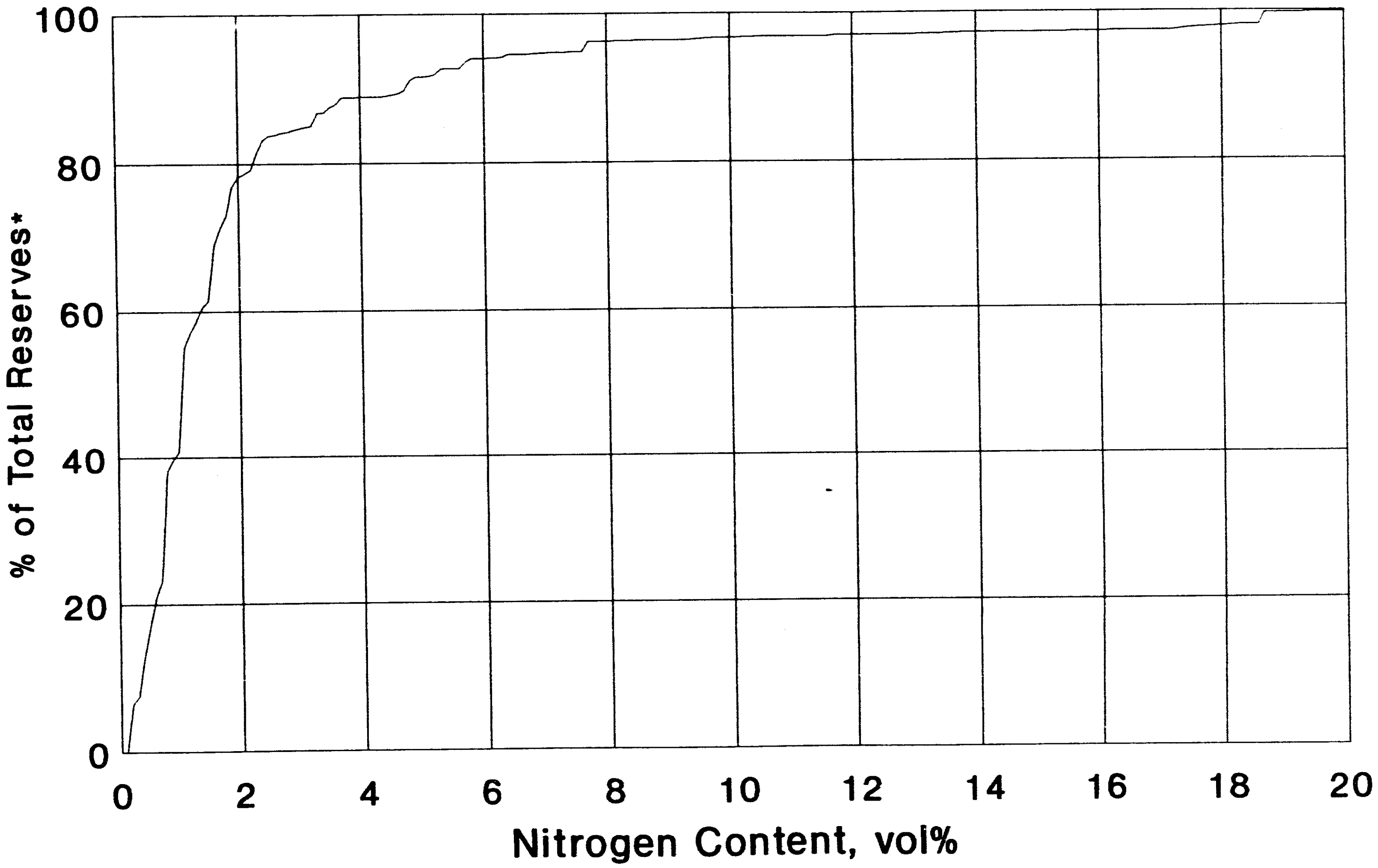


Figure C-8

TOTAL RESERVES VS. NITROGEN CONTENT

Lower 48 States



*Proven + Probable + Undiscovered

Figure C-9

PROVEN RESERVES VS. CARBON DIOXIDE CONTENT

Lower 48 States

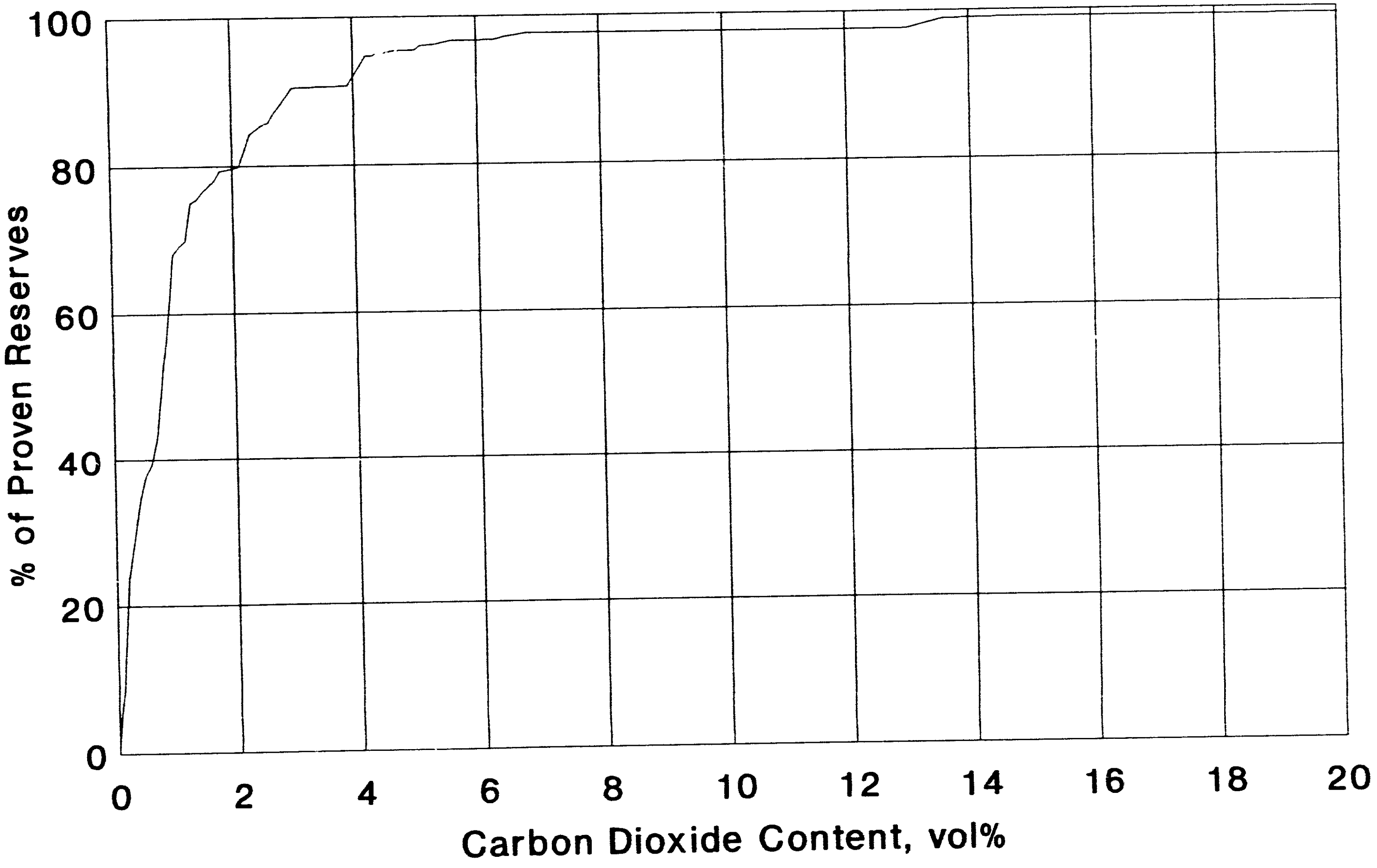


Figure C-10

PROBABLE RESERVES VS. CARBON DIOXIDE CONTENT

Lower 48 States

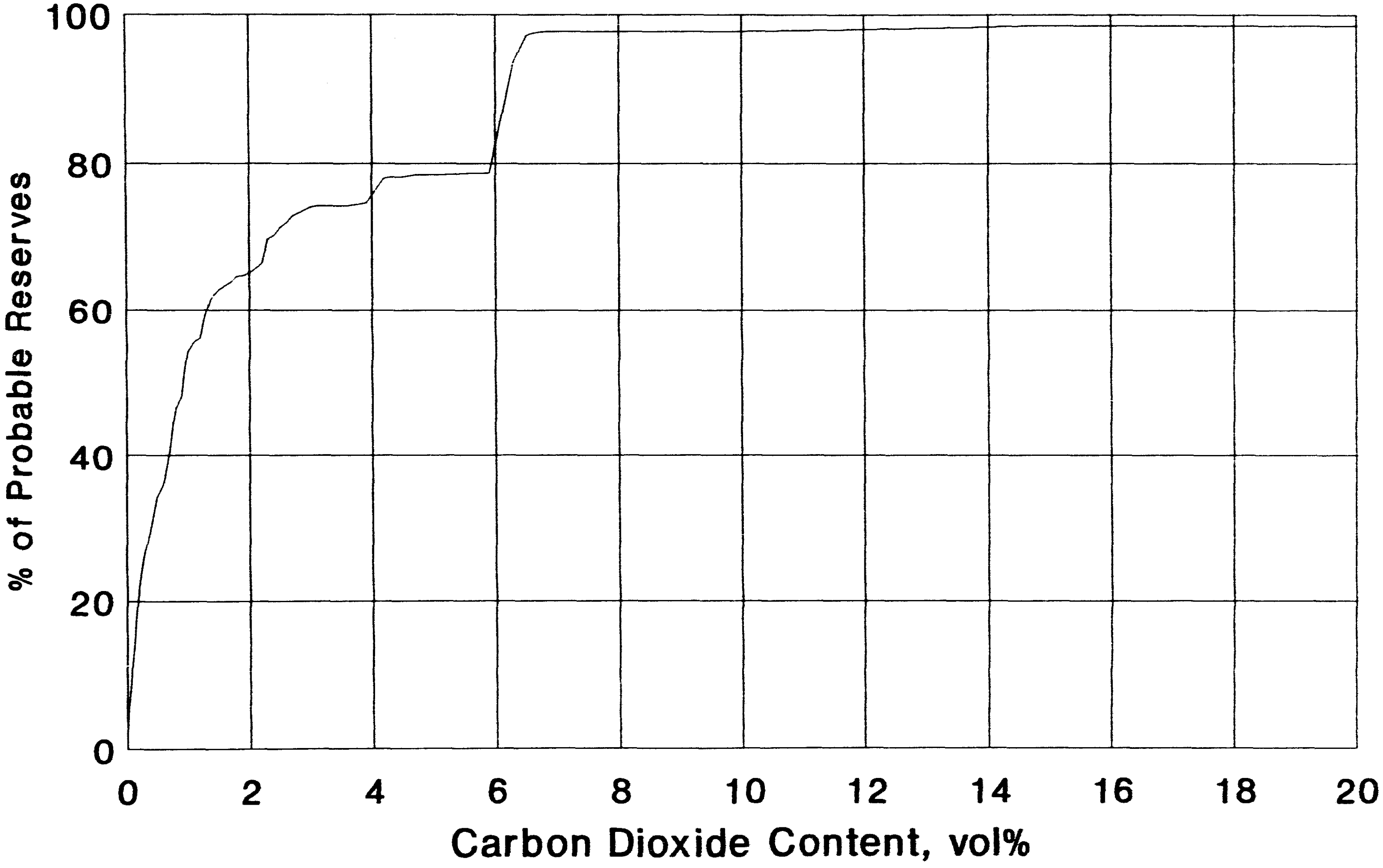


Figure C-11

PROVEN PLUS PROBABLE RESERVES VS. CO_2 CONTENT

Lower 48 States

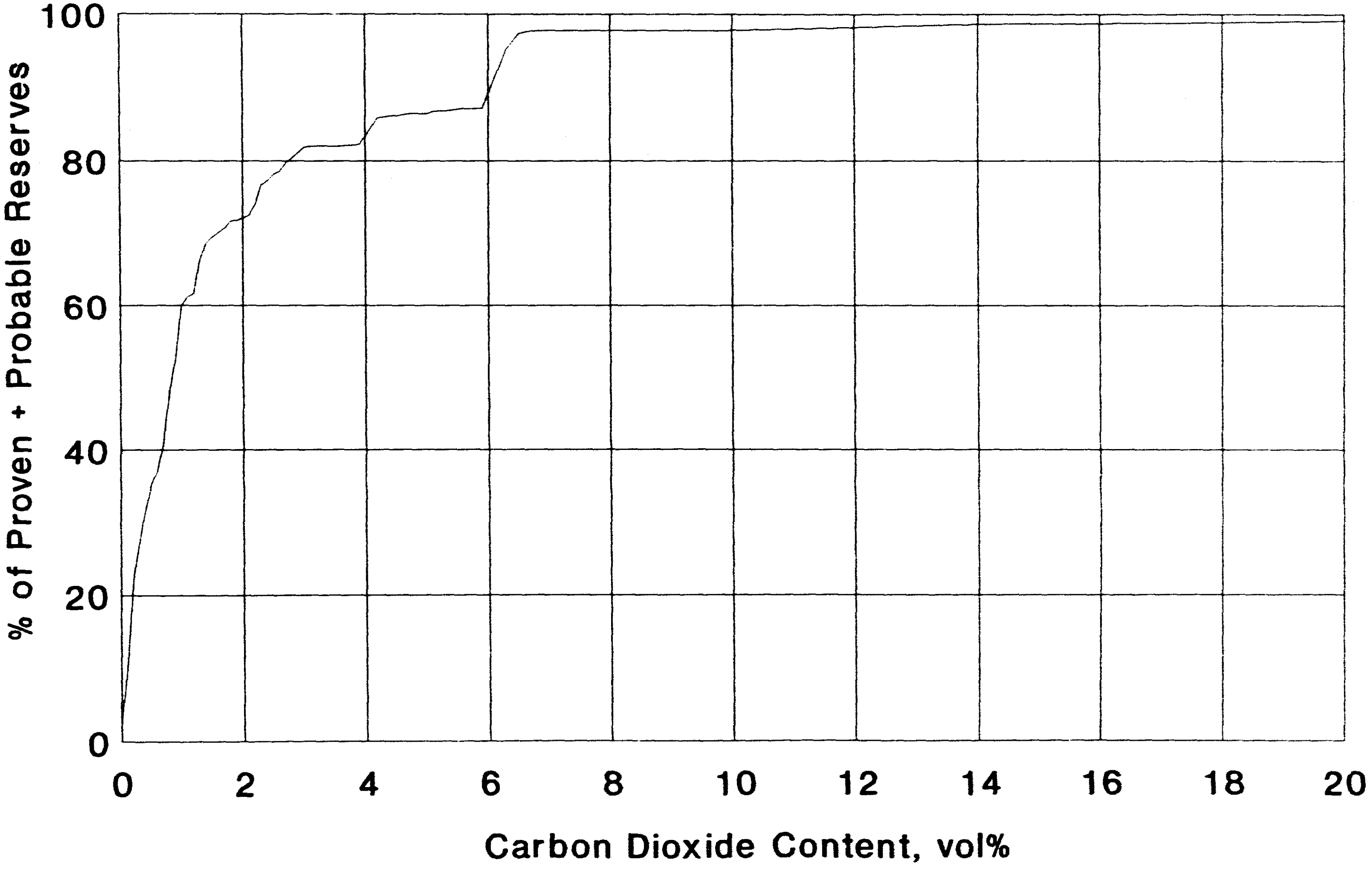


Figure C-12

UNDISCOVERED RESERVES VS. CARBON DIOXIDE CONTENT

Lower 48 States

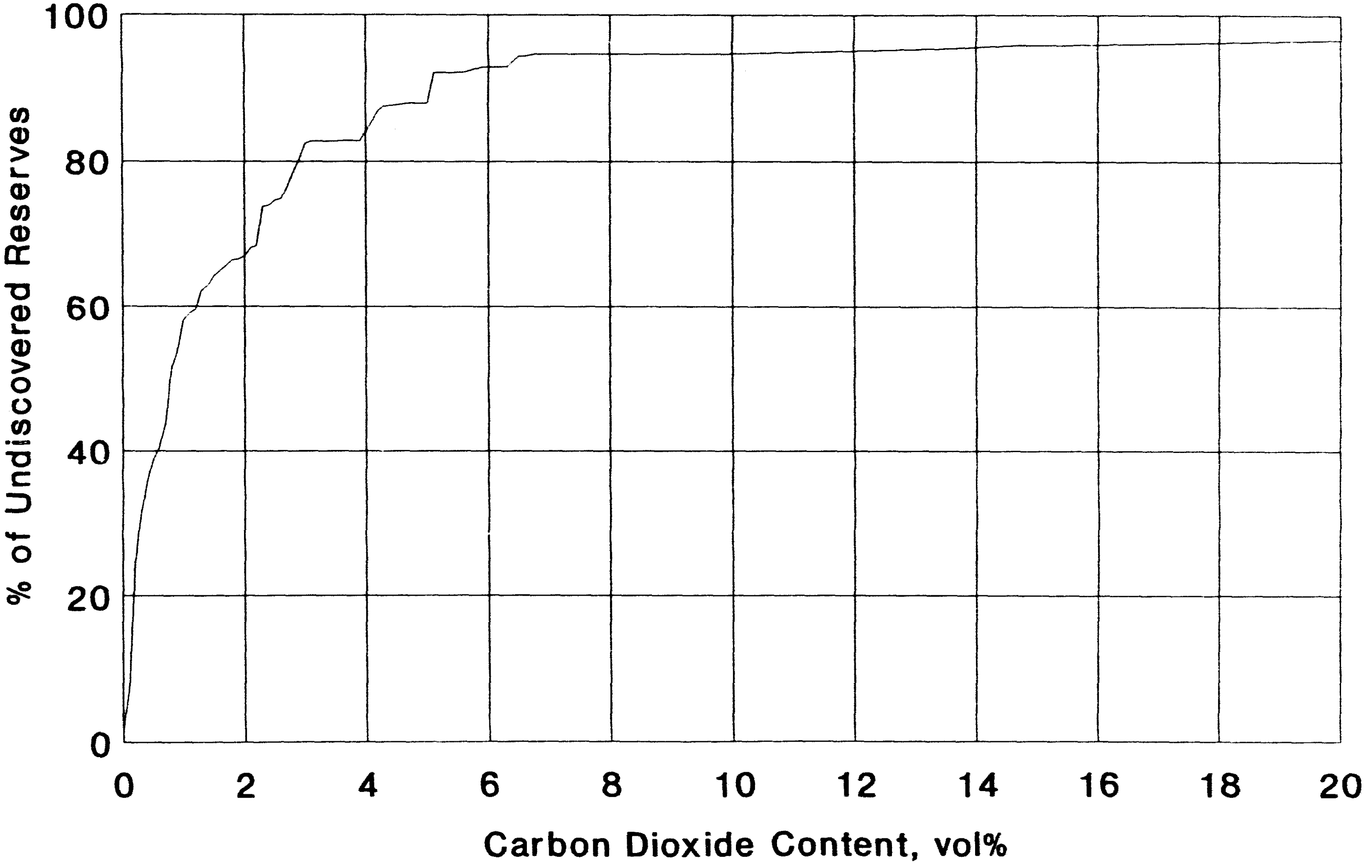
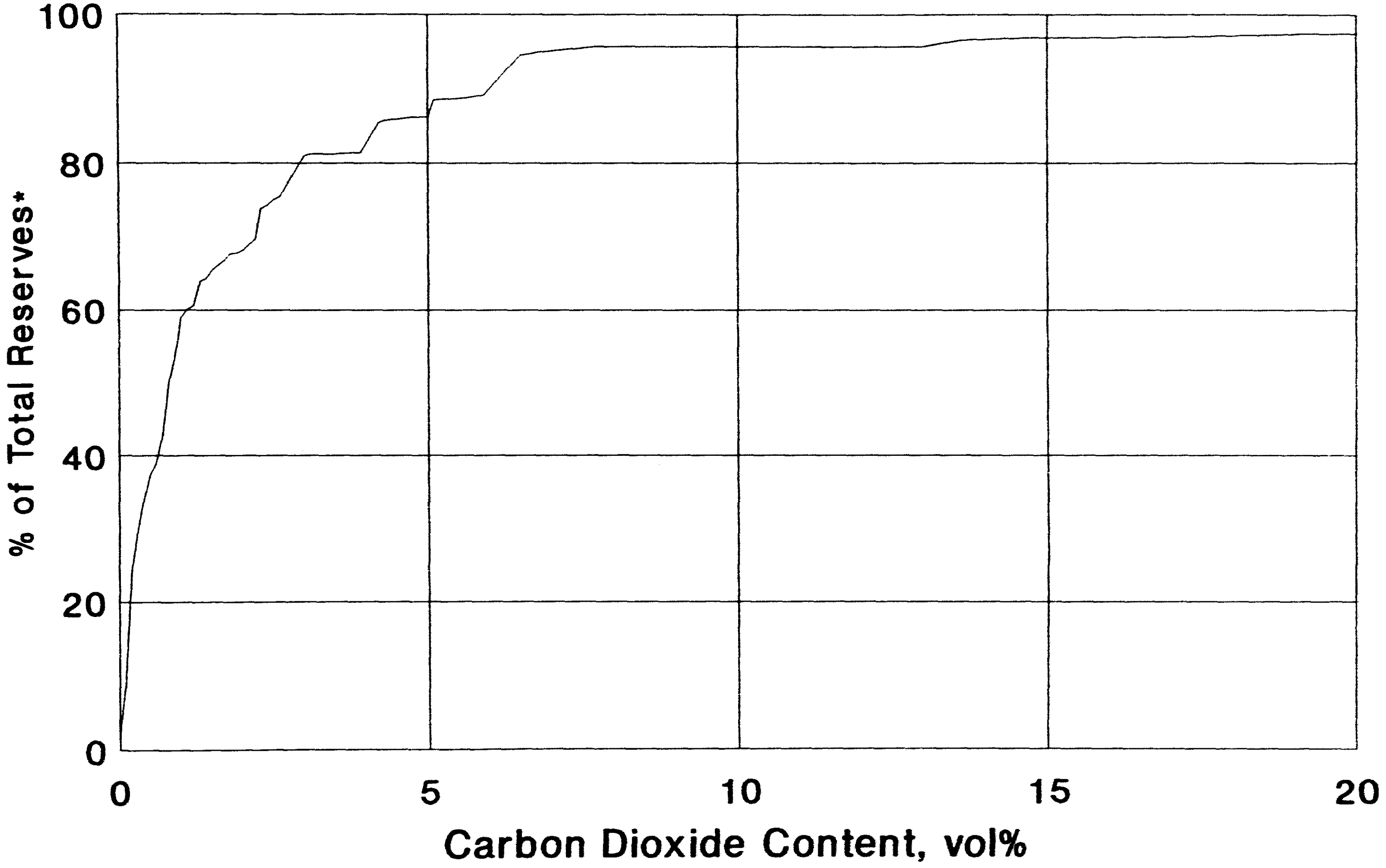


Figure C-13

TOTAL RESERVES VS. CARBON DIOXIDE CONTENT

Lower 48 States



*Proven + Probable + Undiscovered

Figure C-14

PROVEN RESERVES VS. CO_2 PLUS N_2 CONTENT

Lower 48 States

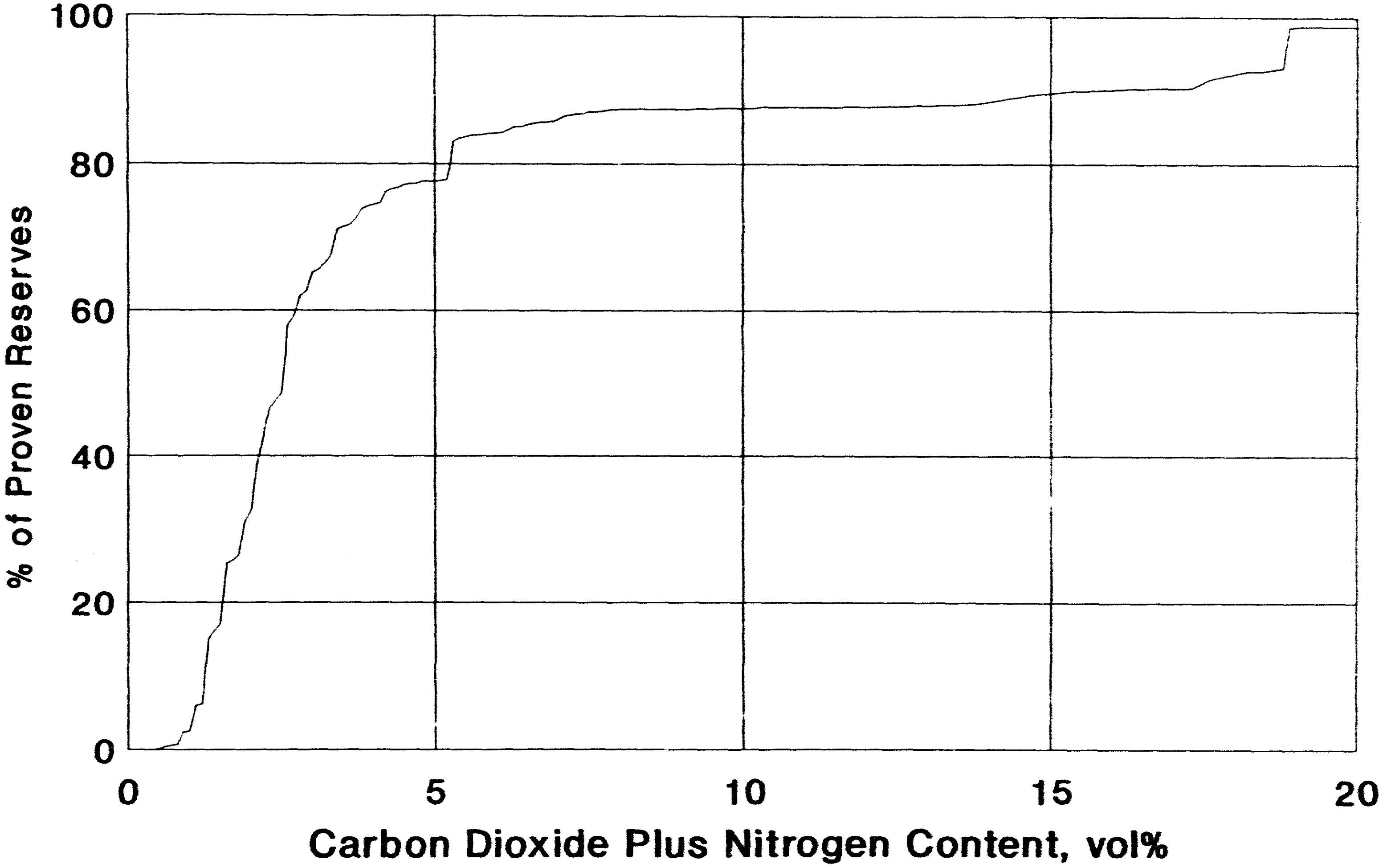


Figure C-15

PROBABLE RESERVES VS. CO_2 PLUS N_2 CONTENT

Lower 48 States

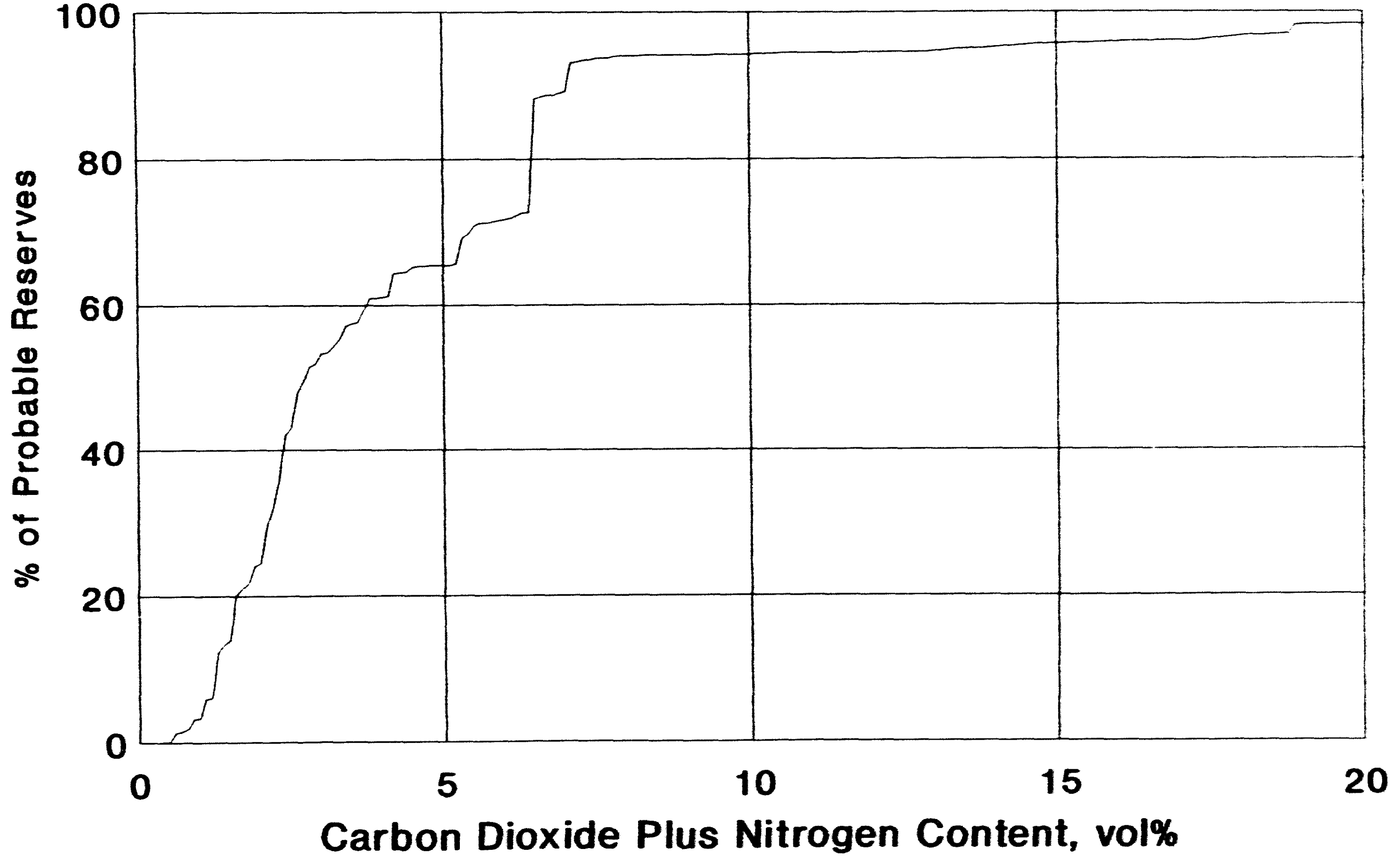


Figure C-16

PROVEN PLUS PROBABLE RESERVES VS. N_2 PLUS CO_2 CONTENT

Lower 48 States

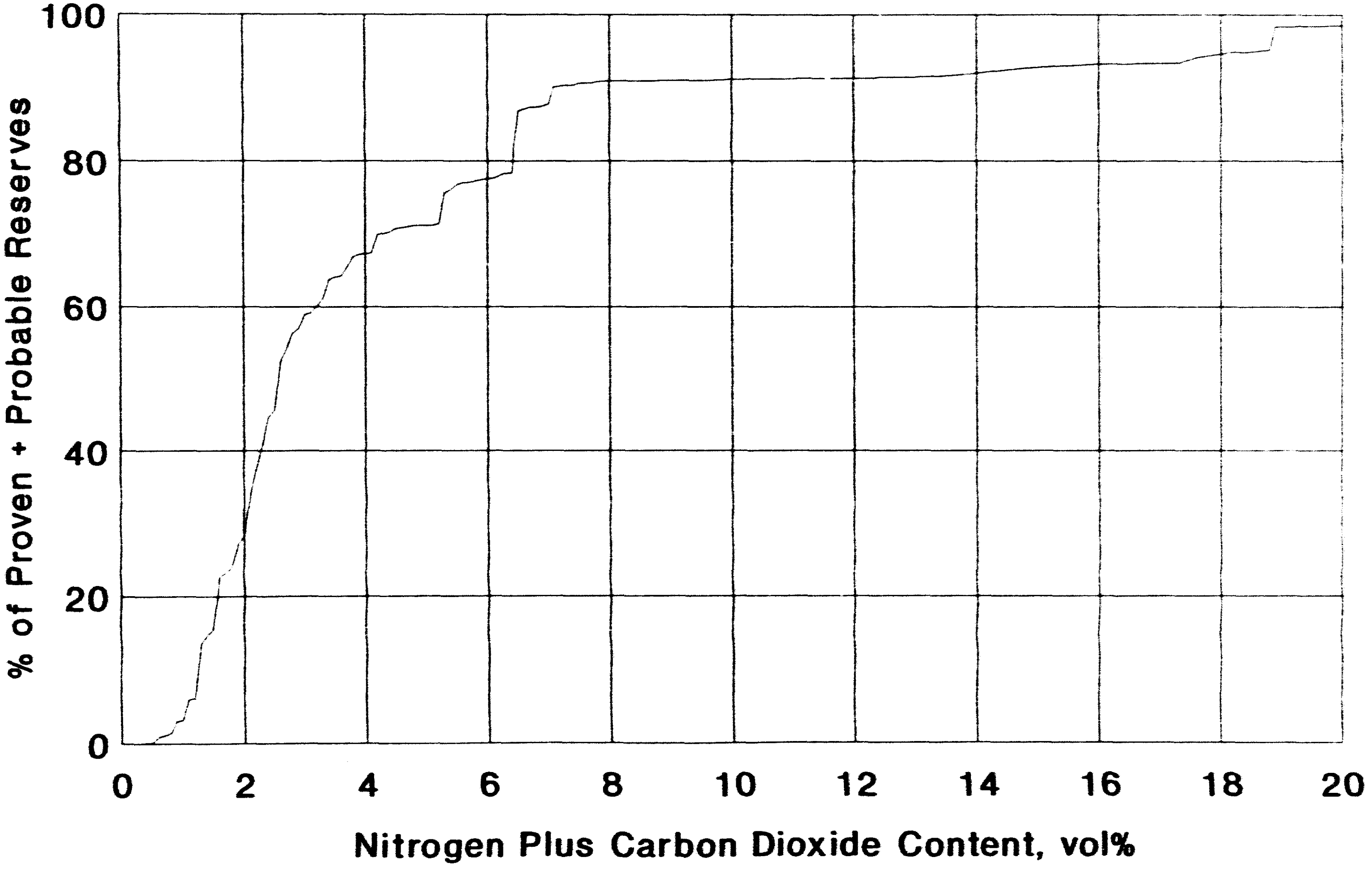


Figure C-17

UNDISCOVERED RESERVES VS. N_2 PLUS CO_2 CONTENT

Lower 48 States

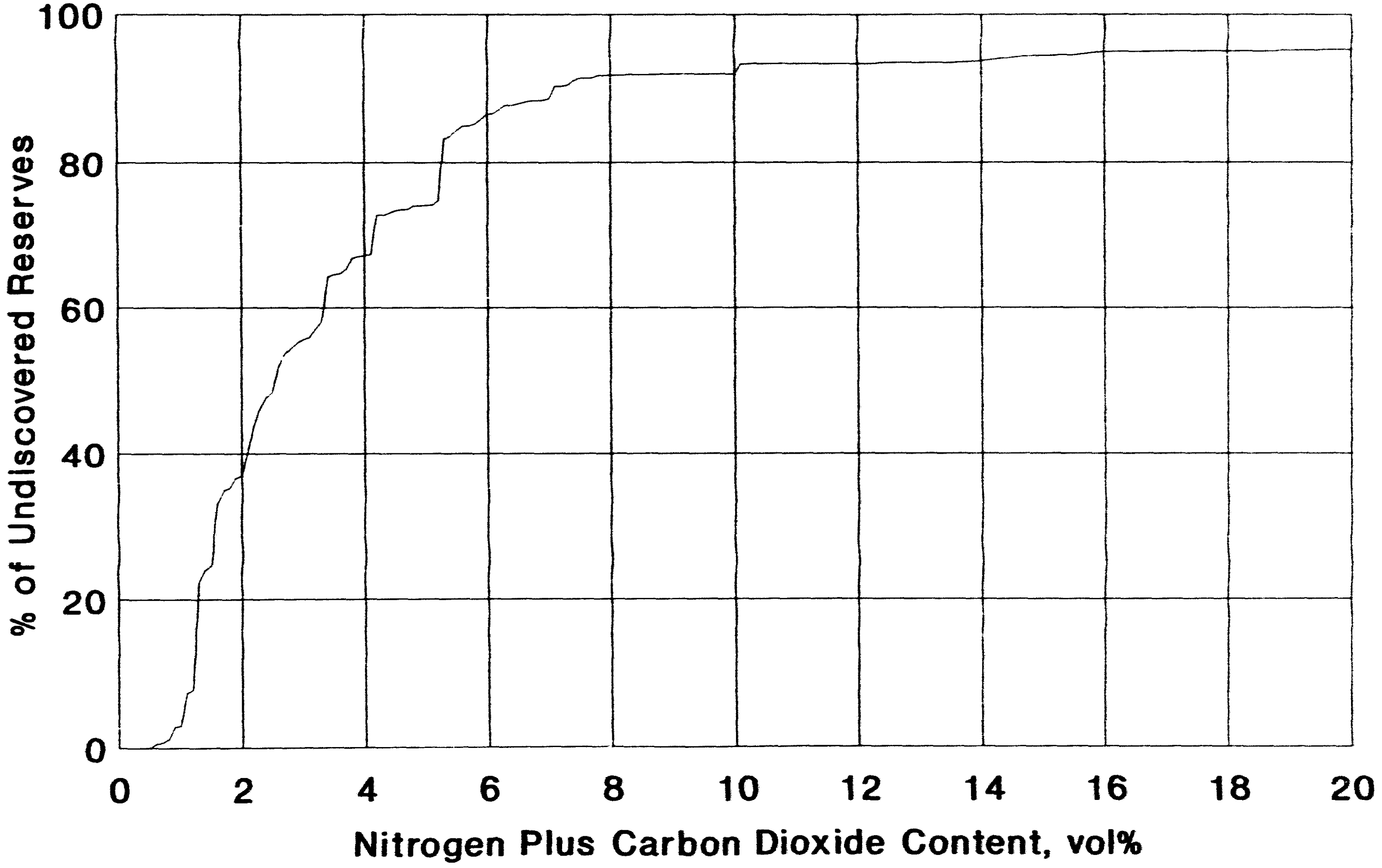
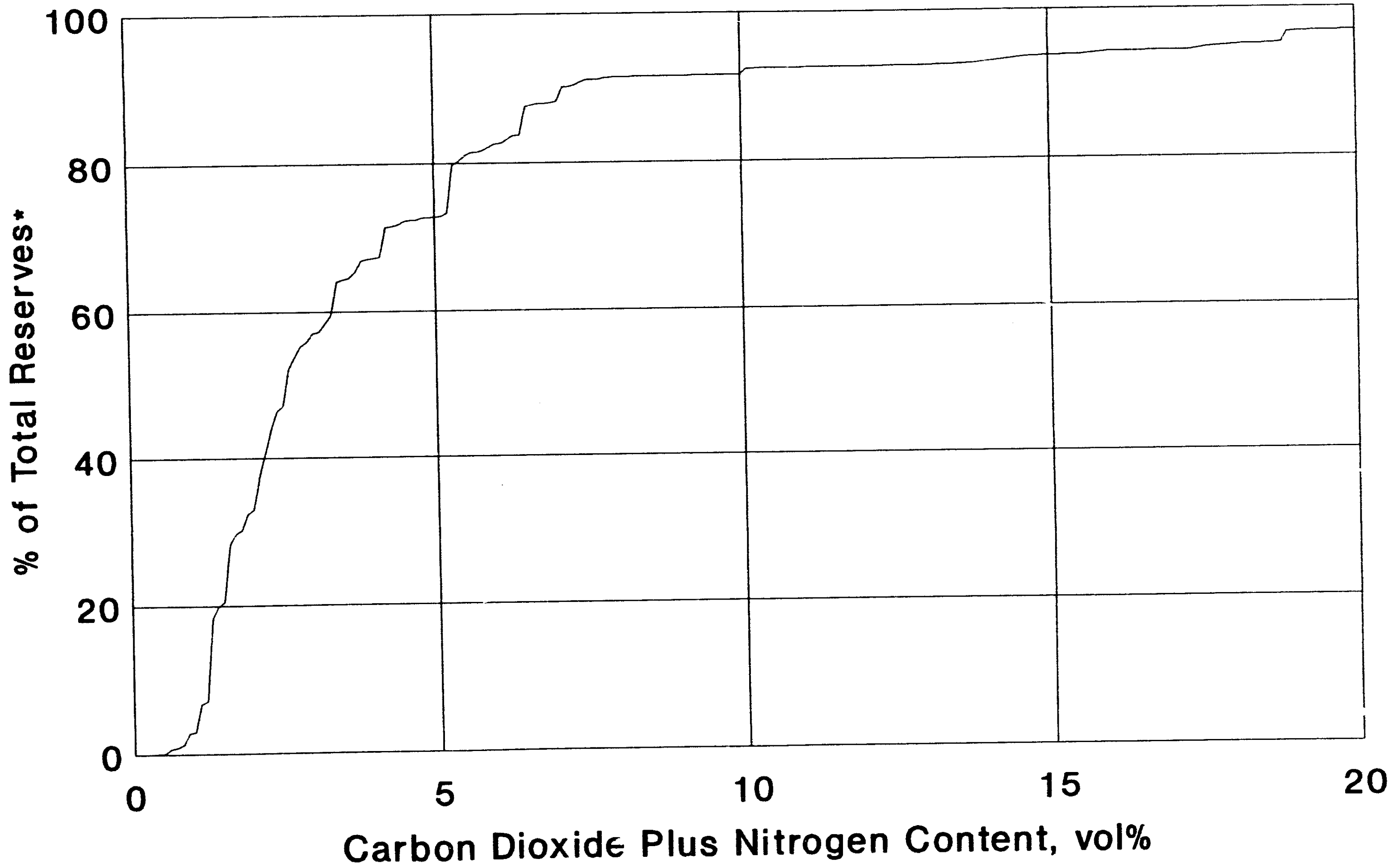


Figure C-18

TOTAL RESERVES VS. CO_2 PLUS N_2 CONTENT

Lower 48 States



* Proven + Probable + Undiscovered

APPENDIX D

EFFECT OF PLANT SIZE ON DESULFURIZATION TOTAL PLANT INVESTMENT AND PRODUCT GAS PRICE

Appendix D

EFFECT OF PLANT SIZE ON DESULFURIZATION TOTAL PLANT INVESTMENT AND PRODUCT GAS PRICE

Since most natural gas contains at least a small quantity of hydrogen sulfide, desulfurization will be a component of almost any natural gas upgrading scheme. Therefore, it is important to know total plant investment and required product gas price for removing H_2S from natural gas streams. This appendix presents total plant investment and required gas price in the initial year (assuming no cost for feed gas, no value for by-product sulfur, and a mid price growth scenario, i. e., product price growth at the rate of inflation) for desulfurizing natural gas as a function of feed gas volume.

Although a variety of processing schemes are in use, for this study it was decided to base the costs on use of an amine process for acid gas removal, followed by a Claus unit with a SCOT tail gas cleanup unit for converting the H_2S to elemental sulfur. Although other processing schemes are used, the chosen scheme is typical of many plants. The scheme is essentially that shown schematically in Figures 5-2 and 5-3 in Section 5.0 of this report.

Total plant investment and required selling price (assuming no cost for feed gas and no value for recovered sulfur) for three price growth scenarios (price growth at half the rate of inflation, price growth at the rate of inflation, and price growth at twice the rate of inflation) are shown in Table D-1 for 0.6% H_2S in the feed gas and in Table D-2 for 2.7% H_2S in the feed gas. This same data is presented graphically in Figures D-1 and D-2. Total plant investment is shown in Figure D-1; and required selling price (mid price growth scenario) in the initial year, assuming no cost feed gas, is shown in Figure D-2.

Costs are provided for two sulfur levels in the feed gas: 0.6% H_2S and 2.7% H_2S. These are the same levels used for cases WSL and WSH discussed in Section 5.0. However, the costs presented in Figures D-1 and D-2 differ from those presented in Section 5.0 in that dehydration costs are not included. At about 100 million SCFD, Table 5-5 gives investments of $12.2 million and $18.7 million for the low and high sulfur cases, respectively. Tables D-1 and D-2 give investments of $10.5 million and $16.7 million for the same cases. This means that the investment cost for dehydration is $1.7-2.0 million. Required selling prices from Table 5-5 are 11.6 and 15.9¢/MSCF for the low and high sulfur cases. Corresponding selling prices from Tables D-1 and D-2 (mid price scenario) are 10.6 and 15.6¢/MSCF. This indicates that dehydration adds 0.3-1.0¢/MSCF to required selling price.

Investment costs were, for the most part, estimated based on costing individual items of equipment and using installation factors to determine installed costs. The methodology discussed in Appendix B was then used to calculate total plant investment and required selling price. Cost estimates should be accurate to about ±25%; however, relative values, that is differences between one plant size and another, should be considerably more accurate.

The gas costs in Figure D-2 represent only the cost of H_2S removal. If further processing is to take place, such as, for example, nitrogen removal, then the costs of the additional processing must be added to the desulfurization cost. The costs in Figures D-1 and D-2 do not include the cost of CO_2 removal, although H_2S and CO_2 are frequently removed simultaneously. If the removal of H_2S and CO_2 is carried out in an integrated unit, the cost should be somewhat less than the cost of separate units for removing these two impurities.

Table D-1

CAPITAL INVESTMENT AND GAS PRICE FOR SULFUR REMOVAL AS A FUNCTION OF PLANT SIZE

0.6% Hydrogen Sulfide in Feed Gas

Feed Rate, 10^6 SCFD	Total Plant Investment, \$$10^6$	Gas Price in Initial Year, ¢/MSCF		
		Low Gas Price Growth[a]	Mid Gas Price Growth[b]	High Gas Price Growth[c]
10	3.40	41.4	34.2	22.4
20	4.47	28.0	23.1	15.1
30	5.38	22.6	18.6	12.2
40	6.21	19.6	16.1	10.6
50	6.99	17.6	14.5	9.5
75	8.81	14.6	12.1	7.9
100	10.49	12.9	10.6	7.0
125	12.06	11.8	9.7	6.4

[a] Price growth at half the inflation rate.

[b] Price growth at the inflation rate.

[c] Price growth at twice the inflation rate.

Table D-2

CAPITAL INVESTMENT AND GAS PRICE FOR SULFUR REMOVAL AS A FUNCTION OF PLANT SIZE

2.7% Hydrogen Sulfide in the Feed Gas

Feed Rate, 10^6 SCFD	Total Plant Investment, $\$10^6$	Gas Price in Initial Year, ¢/MSCF		
		Low Gas Price Growth[a]	Mid Gas Price Growth[b]	High Gas Price Growth[c]
10	4.33	51.7	42.7	28.0
20	6.10	36.5	30.1	19.8
30	7.65	30.3	25.0	16.4
40	9.08	26.8	22.1	14.5
50	10.44	24.4	20.2	13.2
75	13.66	20.9	17.3	11.3
100	16.67	18.9	15.6	10.2
125	19.55	17.5	14.4	9.5

[a] Price growth at half the inflation rate.

[b] Price growth at the inflation rate.

[c] Price growth at twice the inflation rate.

Figure D-1

Total Plant Investment vs. Plant Feed Rate

(Amine, Claus, and SCOT Units)

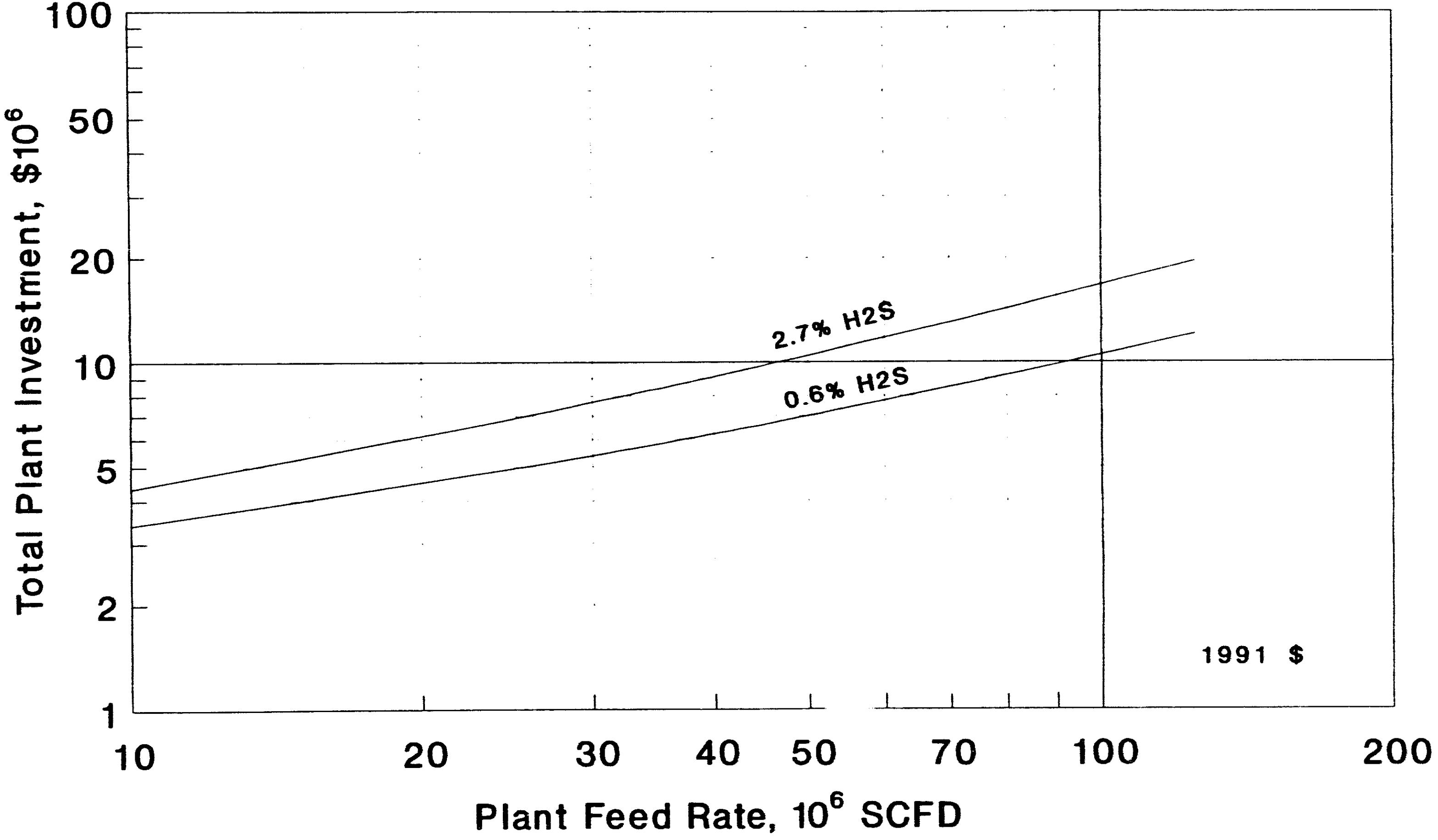
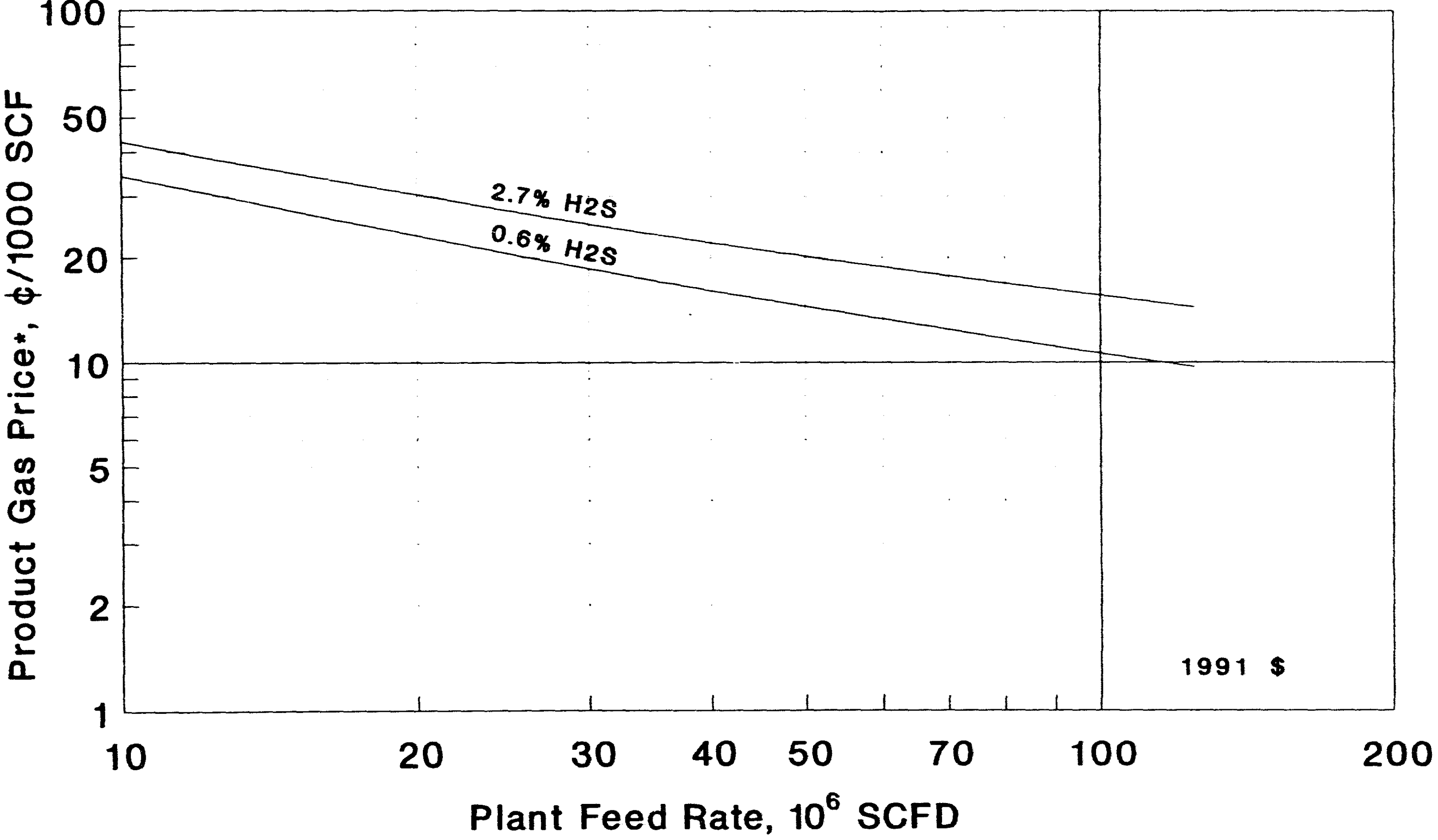


Figure D-2

Required Selling Price vs. Plant Feed Rate

(Amine, Claus, and SCOT Units)



*No cost for gas, no value for sulfur, and mid gas price growth.

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