Field Handling of Natural Gas

Volume 1—Production and Conditioning

THE UNIVERSITY OF TEXAS AT AUSTIN · PETROLEUM EXTENSION SERVICE

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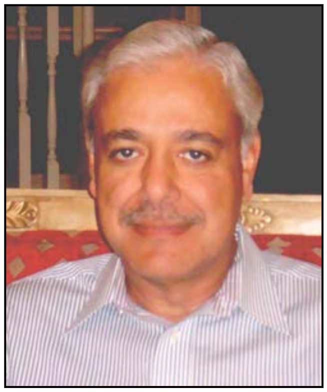
About the Authors

J.C. Kuo (Chen Chuan J. Kuo) is a 39-year veteran of the gas processing, gas treating, and LNG industry. As a senior advisor for Chevron's Energy Technology Company, he has served as the Process Manager/Process Lead for many projects, including the Gas injection/EOR, Wheatstone LNG, Gorgon LNG, Delta Caribe LNG, Casotte Landing, and Sabine Pass LNG terminal projects. He has also served as the technical process reviewer for Angola, Olokola, Algeria, and Stockman LNG projects. Before working at Chevron, J.C. was the Technology Manager for IPSI Bechtel and served as the Process Manager/Process Lead for the Pemex Catarell offshore project, the Egyptian LNG (Idku) trains 1 and 2, China Shell Nan Hai, Chevron Venice gas plant de-bottleneck, Tunisia NRU, and Australian SANTOS projects.

J.C. is a frequent speaker and presenter at international conferences such as AIChE, gas processing and treating conferences, and the LNG Summit. He has contributed to gas processing and LNG technology improvements through patents, books, and many papers. He has also served as co-chair of the AIChE LNG sessions for the topical conferences on natural gas utilization.

His degrees include a B.S. from Chung Yuan Christian University, Taiwan, an M.S. from the University of Houston, both for Chemical Engineering, and an M.S. in Environmental Engineering from Southern Illinois University. He is currently completing his Ph. D. dissertation from the department of Civil and Environmental Engineering, University of Houston. He is a registered Professional Engineer in Texas and a senior member of AIChE. He is the president of the 99 Power Chi Gong Texas divisions.



Dr. Pervaiz Nasir has more than 32 years experience in the oil and gas business. He is currently the General Manager of Gas Processing, Americas, at Shell Global Solutions.

Pervaiz started his career at Shell Development Company in 1981 in research and development and technical support, mostly related to oil and gas processing. In 1986, he moved into licensing and process design of Shell Gas/Liquid Treating technologies. As a member of Shell Midstream from 1991 through 1999, Pervaiz was responsible for the operations support and optimization of existing gas plants and the development and startup of new gas processing facilities. He then joined Enterprise Products Company as Director of Technology. At Enterprise, Pervaiz was responsible for the evaluation of new business ventures/technologies in gas processing, LNG, gas pipelines, and petrochemicals. He returned to Shell Global Solutions in 2006.

Pervaiz holds a B.S. from Middle East Technical University, an M.S. from the University of Alberta, and a Ph.D. from Rice University, all in chemical engineering. He served on the Gas Processors Association (GPA) Phase Equilibria Research Steering Committee from 1983 through 1990, on the GPA LNG Committee until it was dissolved in 2008, and is currently on the GPA Board of Directors. Pervaiz has authored or coauthored over 17 external technical publications and is a coauthor of the book *Plant Processing of Natural Gas*, published in 2008 by The University of Texas at Austin.

Reviewer

Dr. Doug Elliot has over 40 years experience in the oil and gas business, devoted to the design, technology development, and direction of industrial research. He was the former President, COO, and a cofounder (with Bechtel Corporation) of IPSI LLC, a company formed in 1986 to develop technology and provide conceptual design services to oil and gas producing and EPC companies.

Prior to IPSI, Doug was Vice President of Oil and Gas with Davy McKee International. Doug started his career with McDermott Hudson Engineering in the early 1970s following a post-doctoral research assignment under Professor Riki Kobayashi at Rice University, where he developed an interest in oil and gas thermophysical properties research and its application.

Doug has authored or coauthored over 65 technical publications plus 12 patents. He served as a member of the Gas Processors Association (GPA) Research Steering Committee from 1972 to 2001 and as Chairman of the GPSA Data Book Committee on Physical Properties. Doug served as Chairman of the South Texas Section and Director of the Fuels and Petrochemical Division of the AIChE.. He holds a B.S. degree from Oregon State University and M.S. and Ph.D. degrees from the University of Houston, all in chemical engineering. Doug is a Bechtel Fellow and a Fellow of the American Institute of Chemical Engineers.

Units of Measurement

Throughout the world, two systems of measurement dominate: the English system and the metric system. Today, the United States is one of only a few countries that employ the English system.

The English system uses the pound as the unit of weight, the foot as the unit of length, and the gallon as the unit of capacity. In the English system, for example, 1 foot equals 12 inches, 1 yard equals 36 inches, and 1 mile equals 5,280 feet or 1,760 yards.

The metric system uses the gram as the unit of weight, the metre as the unit of length, and the litre as the unit of capacity. In the metric system, 1 metre equals 10 decimetres, 100 centimetres, or 1,000 millimetres. A kilometre equals 1,000 metres. The metric system, unlike the English system, uses a base of 10; thus, it is easy to convert from one unit to another. To convert from one unit to another in the English system, you must memorize or look up the values.

In the late 1970s, the Eleventh General Conference on Weights and Measures described and adopted the Systeme International (SI) d'Unites. Conference participants based the SI system on the metric system and designed it as an international standard of measurement.

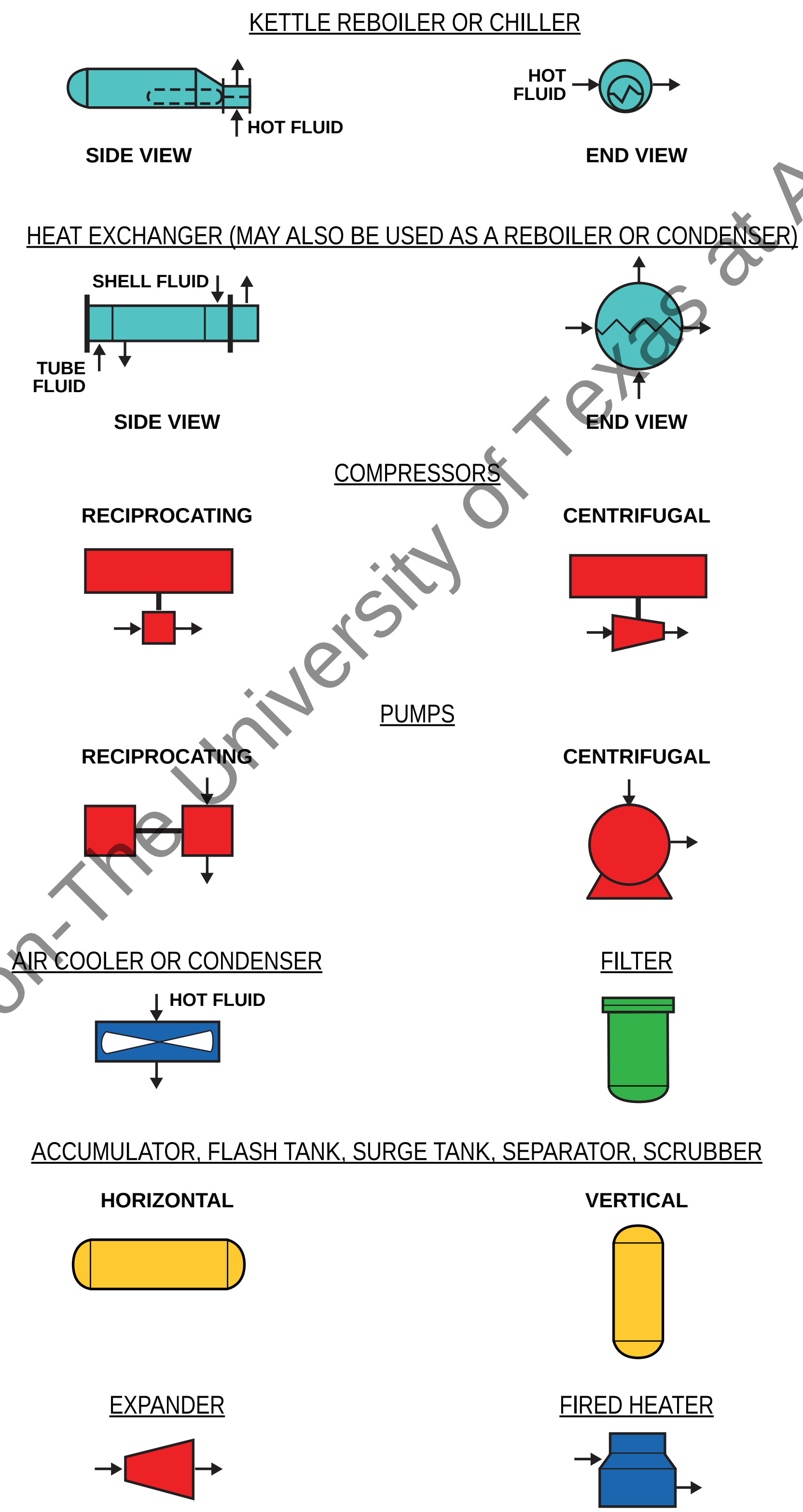
The Rotary Drilling Series gives both English and SI units. And because the SI system employs the British spelling of many of the terms, the book follows those spelling rules as well. The unit of length, for example, is metre, not meter. (Note, however, that the unit of weight is gram, not gramme.)

To aid U.S. readers in making and understanding the conversion system, we include the table on the next page.

English-Units-to-SI-Units Conversion Factors

Quantity or Property	English Units	Multiply English Units By	To Obtain These SI Units
Length, depth, or height	inches (in.)	25.4	millimetres (mm)
		2.54	centimetres (cm)
	feet (ft)	0.3048	metres (m)
	yards (yd)	0.9144	metres (m)
	miles (mi)	1609.344	metres (m)
		1.61	kilometres (km)
Hole and pipe diameters, bit size	inches (in.)	25.4	millimetres (mm)
Drilling rate	feet per hour (ft/h)	0.3048	metres per hour (m/h)
Weight on bit	pounds (lb)	0.445	decanewtons (dN)
Nozzle size	32nds of an inch	0.8	millimetres (mm)
Volume	barrels (bbl)	0.159	cubic metres (m^3)
		159	litres (L)
	gallons per stroke (gal/stroke)	0.00379	cubic metres per stroke (m^3/stroke)
	ounces (oz)	29.57	millilitres (mL)
	cubic inches ($in.^3$)	16.387	cubic centimetres (cm^3)
	cubic feet (ft^3)	28.3169	litres (L)
		0.0283	cubic metres (m^3)
	quarts (qt)	0.9464	litres (L)
	gallons (gal)	3.7854	litres (L)
	gallons (gal)	0.00379	cubic metres (m^3)
	pounds per barrel (lb/bbl)	2.895	kilograms per cubic metre (kg/m^3)
	barrels per ton (bbl/tn)	0.175	cubic metres per tonne (m^3/t)
Pump output and flow rate	gallons per minute (gpm)	0.00379	cubic metres per minute (m^3/min)
	gallons per hour (gph)	0.00379	cubic metres per hour (m^3/h)
	barrels per stroke (bbl/stroke)	0.159	cubic metres per stroke (m^3/stroke)
	barrels per minute (bbl/min)	0.159	cubic metres per minute (m^3/min)
Pressure	pounds per square inch (psi)	6.895	kilopascals (kPa)
		0.006895	megapascals (MPa)
Temperature	degrees Fahrenheit (°F)	$\frac{°F - 32}{1.8}$	degrees Celsius (°C)
Mass (weight)	ounces (oz)	28.35	grams (g)
	pounds (lb)	453.59	grams (g)
		0.4536	kilograms (kg)
	tons (tn)	0.9072	tonnes (t)
	pounds per foot (lb/ft)	1.488	kilograms per metre (kg/m)
Mud weight	pounds per gallon (ppg)	119.82	kilograms per cubic metre (kg/m^3)
pounds per cubic foot (lb/ft^3)		16.0	kilograms per cubic metre (kg/m^3)
Pressure gradient	pounds per square inch per foot (psi/ft)	22.621	kilopascals per metre (kPa/m)
Funnel viscosity	seconds per quart (s/qt)	1.057	seconds per litre (s/L)
Yield point	pounds per 100 square feet (lb/100 ft^2)	0.48	pascals (Pa)
Gel strength	pounds per 100 square feet (lb/100 ft^2)	0.48	pascals (Pa)
Filter cake thickness	32nds of an inch	0.8	millimetres (mm)
Power	horsepower (hp)	0.75	kilowatts (kW)
Area	square inches ($in.^2$)	6.45	square centimetres (cm^2)
	square feet (ft^2)	0.0929	square metres (m^2)
	square yards (yd^2)	0.8361	square metres (m^2)
	square miles (mi^2)	2.59	square kilometres (km^2)
	acre (ac)	0.40	hectare (ha)
Drilling line wear	ton-miles (tn•mi)	14.317	megajoules (MJ)
		1.459	tonne-kilometres (t•km)
Torque	foot-pounds (ft•lb)	1.3558	newton metres (N•m)

Flow Diagram Symbols



1
Characteristics of Natural Gas

In this chapter:

- Components and characteristics of natural gas
- Temperature and pressure
- Physical properties of natural gas
- Heat energy and heating values
- Ideal gas law
- Equations of state and equilibrium

Natural gas is a highly compressible mixture of *hydrocarbons* and may also contain significant amounts of nitrogen, helium, carbon dioxide, hydrogen sulfide, and water vapor. When extracted from an underground reservoir, some of the impurities in natural gas are considered undesirable and must be removed before the gas can be sold.

The petroleum industry generally classifies natural gas by its relationship to crude oil in an *underground reservoir*. *Associated gas* is the term used for natural gas that is in contact with crude oil in a reservoir. Associated gas may be a *gas cap* over the crude oil or a solution of gas and oil. *Nonassociated gas* exists in reservoirs that have no crude oil. Whether associated or nonassociated, produced gas streams are highly variable in composition and can contain a wide range of hydrocarbon and non-hydrocarbon components.

Gas facilities operated in the field are mainly used to condition the gas to make it marketable or to prepare it for further processing. These field facilities remove impurities, water, and excess hydrocarbon liquids. The final field operations involve the use of pressure-reducing regulators or, more often, compressors to raise the pressure.

Processing plants are usually designed to recover certain valuable natural gas products over and above those needed to make the gas marketable—that is, natural gasoline, butanes, propane, and ethane. Plants may also be designed to recover elemental *sulfur* from the hydrogen sulfide gas removed from raw natural gas. Another function of plants is to separate the recovered liquid hydrocarbons into various mixtures or pure products by the use of *fractionating columns*. Plant processes usually incorporate many of the functions ordinarily performed by field facilities. The processed natural gas that enters the sales transmission pipeline is primarily a mixture of *methane* (usually >95%) with varying amounts of other heavy hydrocarbons and non-hydrocarbons.

COMPOSITION OF NATURAL GAS

Natural gas is primarily methane mixed with varying quantities of ethane, propane, butanes, pentanes, hexanes, and other heavier hydrocarbons. Natural gas may also contain some non-hydrocarbon components such as carbon dioxide, hydrogen sulfide, nitrogen, helium, and water vapor. Trace amounts of other components, such as mercury, may also be present.

Natural gases produced from different reservoirs can have very distinct compositions. No single specific composition can be considered the definitive composition of natural gas. Table 1.1 shows three examples of produced natural gas streams and their compositions.

In this chapter:

- The geology of oil and gas accumulations
- Shale gas
- Calculating amounts of original gas in place
- Estimating gas reserves
- Determining gas well ratings
- Well and production equipment

2 Natural Gas Production

Oil and gas are known as fossil fuels. The most prevalent theory of their origin is organic; that is, that they originated millions of years ago from living organisms in ancient seas. Falling to the seafloor as they died, these organisms built accumulations that eventually were covered by other sediment. Because of the pressure exerted by both water and sediment, the organic material gradually became transformed into petroleum and natural gas.

OIL AND GAS ACCUMULATIONS

For oil and gas to accumulate, three conditions are necessary. First, an organic source must exist. Second, a permeable porous bed or reservoir rock must exist to allow the oil and gas to flow through it. Finally, there must be a *trap* that creates a barrier to the fluid flow that causes the petroleum and natural gas to accumulate.

Migration

It is generally accepted that any accumulation of oil and gas is a result of migration of widely dispersed and relatively small individual quantities of hydrocarbons to a more concentrated deposit as is found in a reservoir. The source material may be in close proximity to the present pool. However, it is thought that in most cases the organic source material that forms petroleum and natural gas is widely distributed in the sediments and that accumulations are the result of the combination of small portions from near and far. Several natural forces and conditions that promote such *migration* include:

- Compaction of source beds by the weight of the overlying rock. This provides a driving force that tends to expel fluids through pore channels or fractures to regions of lower pressure and normally shallower depth.
- Gravitational separation of gas, oil, and water in porous rocks that are usually water saturated.
- Pressure differential from any cause between two interconnected points in a permeable medium.
- *Faulting* of the earth's strata.

3

Natural Gas and Liquid Separation

In this chapter:

- Separation of well stream gas in the field
- Types of conventional separators and how they work
- Filter separators to remove small liquid and solid particles
- Stage separation
- Low-temperature separation systems
- Condensate stabilization

WELL STREAM SEPARATION

A natural gas *well stream* produced from a reservoir is predominantly a complex mixture of different compounds of hydrogen and carbon with different densities, vapor pressures, and other physical characteristics. A typical well stream is a high-velocity, turbulent, constantly expanding mixture of gases and hydrocarbon liquids mixed with water vapor, free water, solids, and other contaminants. As it flows from the hot, high-pressure reservoir, the well stream undergoes continuous pressure and temperature reduction. Gases evolve from the liquids, water vapor condenses, and some of the well stream changes in character from liquid to bubbles, mist, and free gas. The high-velocity gas carries liquid droplets, and the liquid carries gas bubbles.

The purpose of *field processing* of natural gas is to remove and separate the well stream into salable gas and petroleum liquids while recovering the maximum amounts of each at the lowest possible overall cost. Typical specifications considered for the quality of salable gas include pressure, temperature, higher heating value (HHV), *Wobbe Index*, gas *hydrocarbon dew point (HCDP)* at some pressure range, inert total including nitrogen (N_2), carbon dioxide (CO_2), oxygen (O_2), water ((H_2O), total sulfur, hydrogen sulfide, and radioactive components. Field processing of natural gas consists of four basic processes:

- Separation of the gas from *entrained* solids and free liquids such as crude oil, hydrocarbon condensate, and water
- Conditioning the gas to remove other undesirable components, such as hydrogen sulfide and/or carbon dioxide
- Conditioning the gas to remove condensable water vapor, which under certain conditions, may cause hydrate formation
- Processing the gas to remove condensable and recoverable hydrocarbon components

4 Flow Assurance

In this chapter:

- How and why hydrates form
- Ground temperature effect on gas saturated with water vapor
- Hydrate inhibitors and functions
- Heaters and their components

Most natural gas contains a substantial amount of water vapor when it is produced from a well or separated from an associated crude oil stream. If water vapor is not removed from the gas stream, it will condense into liquid and may cause hydrate formation as the gas is cooled from the high reservoir temperature to the cooler surface temperature. Liquid water usually accelerates corrosion and the solid hydrates can pack solidly in gas gathering systems, resulting in partial or complete blockage of flow lines.

Hydrates are solid compounds that form as crystals that look like snow or ice. Hydrates are water *clathrates* in which light hydrocarbons are trapped in a water lattice. They are about 10% hydrocarbon and 90% water. Hydrates have a specific gravity of about 0.98 and usually float in water but sink in hydrocarbon liquids. Water along with some turbulence in the flowing gas stream is always necessary to produce hydrates (figs. 4.1 and 4.2).

Photo by Dr. Alex Freitas for Petrobras

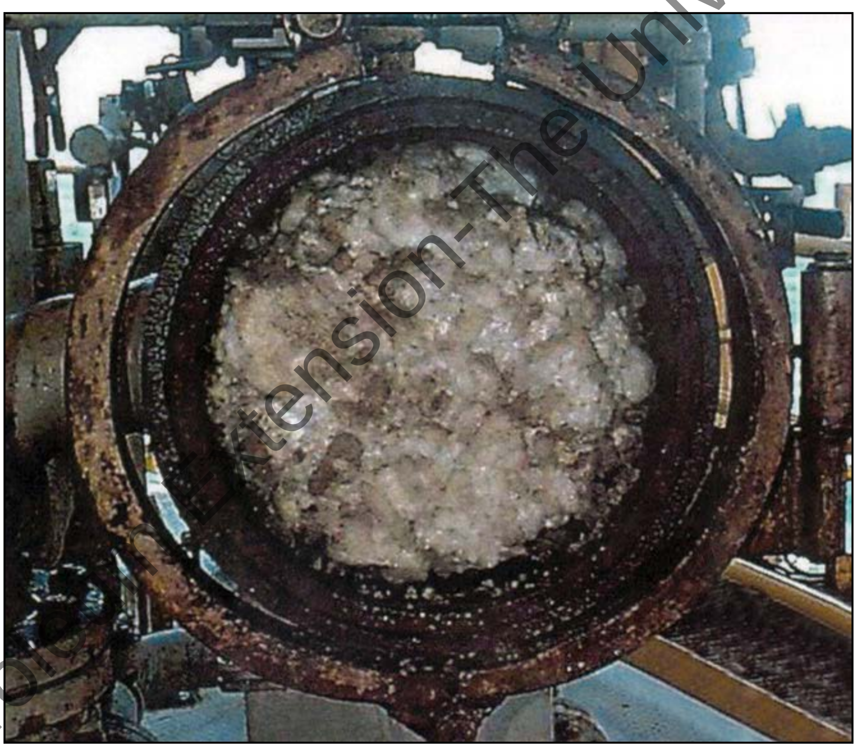


Figure 4.1 Hydrate plug

5 Dehydration of Natural Gas

In this chapter:

- Dehydration of natural gas through absorption and adsorption
- Hydrate formation control through dew-point depression
- Liquid-desiccant dehydrator systems and how they operate
- Plant operation problems with the use of liquid-desiccant dehydrators
- Solid-desiccant dehydrator systems and how they operate
- Use of the hydrocarbon recovery unit

Natural gases contain water vapor that must be removed to make gas marketable. Water vapor can condense in pipelines as the pressure and temperature changes. The condensed water accumulates at low points along the pipeline—and can reduce its flow capacity, result in the formation of solid gas hydrates, and corrode the pipeline, especially if CO_2 and H_2S are present in the gas. *Dehydration* is the process of removing water vapor from natural gas to prevent condensation of water as pressure and temperature conditions change during transmission and processing of the gas. Several methods are used to dehydrate gases (fig. 5.1).

ABSORPTION AND ADSORPTION

Almost all gas moved through transmission lines is dehydrated by either absorption or adsorption. *Absorption* is a mass transfer process that removes water vapor by bubbling the gas upward through liquids that have a special affinity for water. Removing water vapor by making the gas flow through a bed of granular solids with an affinity for water is *adsorption.*

The *dew point* of natural gas is the temperature at any specified pressure at which the gas is saturated with water vapor. *Saturation* means that the gas contains as much water (in vapor form) as possible at a specified pressure and temperature.

The liquid or solid that has an affinity for water and is used in the contactor during absorption or adsorption is called the *desiccant*. Two major types of dehydration equipment in use at this time are the *liquid desiccant* dehydrator and the *solid desiccant dehydrator*. Each has its advantages and disadvantages and its own region of application.

6 Miscellaneous Gas Conditioning

In this chapter:

- Purpose and function of natural gas sweetening
- Nonregenerative processes for removing acid gases
- Regenerative processes for removing acid gases
- Quality and interchangeability of natural gas
- Btu control in natural gas

Natural gas is a mixture of hydrocarbons and impurities such as water, carbon dioxide, hydrogen sulfide, and, in some cases, other sulfur species like *mercaptans*. Some or all of these impurities must be removed to make the gas marketable or to process it further. The removal of H_2S, CO_2, and other sulfur species is referred to as *gas treating* or *sweetening*.

A natural gas stream also contains varying amounts of heavier hydrocarbon components such as ethane, propane, butanes, and pentanes. Removal of the heavy hydrocarbons may be required to meet heating value and/or hydrocarbon dew-point specifications required by sales gas pipelines. In some cases, the heavier hydrocarbons are extracted from the gas stream because they are worth more when sold as liquids rather than for their heating value when left in the gas.

There are several common gas sweetening methods and processes used to remove heavy hydrocarbon to control the heating value and/or hydrocarbon dew point of a natural gas stream. See the references at the end of this chapter for further reading about the deeper recovery of heavier hydrocarbons including ethane.

GAS SWEETENING

Removal of H_2S, CO_2, and mercaptans from a gas stream is referred to as gas sweetening. H_2S, CO_2, and mercaptans are called acid gases, because in the presence of water they form acids or acidic solutions. Treated gas specifications for sales pipelines are usually quite stringent. Typical U.S. sales gas contracts require:

H_2S < 0.25 grains/100 scf (approximately 4 ppmv)
Total sulfur compounds < 5 grains/100 scf (approximately 80 ppmv)
CO_2 < 2% mole

Note: 1 lb-mass = 7000 grains; ppmv = parts per million by volume

H_2S must be removed because it is extremely toxic (poisonous) and cannot be tolerated in gases used for domestic/industrial fuels. H_2S in the presence of water is very corrosive and can cause premature failure of valves, pipelines, and pressure vessels. It can also cause catalyst poisoning (destruction of properties so that the catalyst becomes ineffective) in refinery operations, requiring several expensive precautionary measures.

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To obtain additional training materials, contact:

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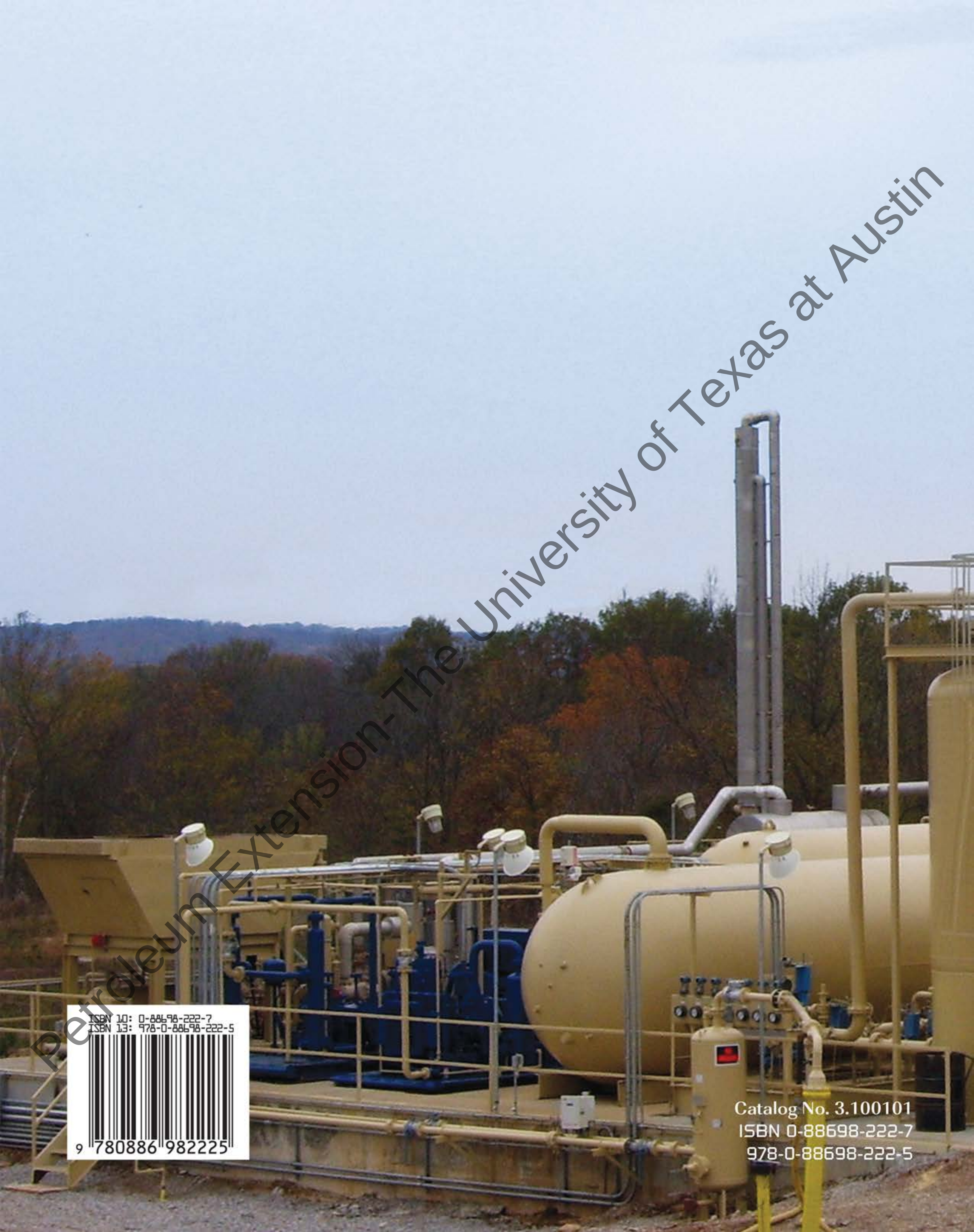

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