GAS 101:
The Natural Gas Delivery System

Understanding How It Works & the Major Components Used

EYSCO

MAGNOLIA RIVER
NOTHING RUNS DEEPER

Ed Young Sales Company, Inc. and Magnolia River Services, Inc.

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SECTION ONE

HOW DOES THE NATURAL GAS DELIVERY SYSTEM WORK?

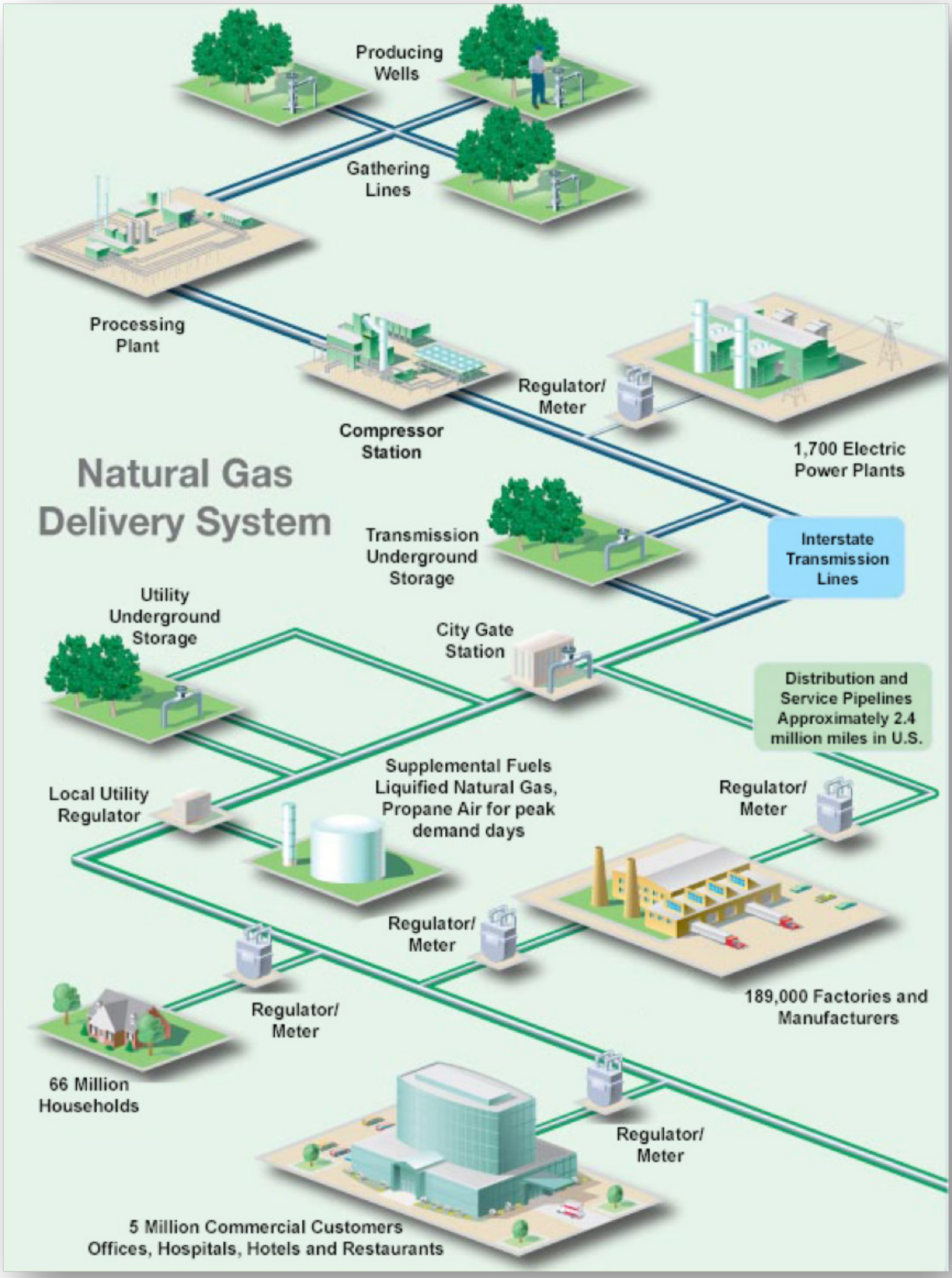
OVERVIEW

Gas flowing from high to low pressure is the fundamental principle of the natural gas delivery system. The delivery system is constantly trying to balance out from a pressure standpoint. Without a pressure differential between the upstream and downstream sections of the system, the gas would not flow.

From the well, natural gas goes into gathering lines, which are like branches on a tree, getting larger as they get closer to a central collection point. This collection point can be either a storage facility or a processing plant where separation of all the various hydrocarbons and fluids within the raw natural gas is performed to produce what is known as pipeline quality dry natural gas. From the processing plant, natural gas is then transported throughout the country in Transmission lines. Local Distribution Companies (LDCs) take transfer of natural gas from the Transmission lines through Gate Stations where pressure is reduced (among other functions) and connected to branches within their distribution system. These branches include district regulators that further reduce pressure and pipe diameter. The gas is moved through the distribution system and eventually to the end-user using either steel or polyethylene pipe. At the customer's site, the natural gas passes through a regulator/meter set and ultimately ends up at the burner tip.

The process from the Transmission line to the end-user is often referred to as "main to meter". The main is the Transmission and/or the LDCs pipe that feeds the industrial, commercial, or residential customer's burner tip; or where the gas supplies the various gas equipment needs of the customer – boiler, furnace, stove, fire logs, water heater, etc.

The amount of time it takes for a molecule of gas to travel from the gathering line to a burner tip (depending on conditions) can be about two (2) weeks (AGA).


Natural Gas Delivery System
Producing Wells
Gathering Lines
Processing Plant
Compressor Station
Regulator/ Meter
1,700 Electric Power Plants
Transmission Underground Storage
Interstate Transmission Lines
Utility Underground Storage
City Gate Station
Distribution and Service Pipelines Approximately 2.4 million miles in U.S.
Local Utility Regulator
Supplemental Fuels Liquified Natural Gas, Propane Air for peak demand days
Regulator/ Meter
Regulator/ Meter
189,000 Factories and Manufacturers
Regulator/ Meter
66 Million Households
Regulator/ Meter
5 Million Commercial Customers Offices, Hospitals, Hotels and Restaurants

A BRIEF HISTORY OF NATURAL GAS

Although naturally occurring gas has been known since ancient times, its commercial use is relatively recent. Around 1000 B.C., the famous Oracle at Delphi on Mount Parnassus in ancient Greece was built where natural gas seeped from the ground in a flame. Around 500 B.C., the Chinese started using crude bamboo "pipelines" to transport gas that seeped to the surface and to use it to boil sea water to get drinkable water. The first commercialized natural gas occurred in Great Britain. Around 1785, the British used natural gas produced from coal to light houses and streets. In 1816, Baltimore, Maryland used this type of manufactured natural gas to become the first city in the United States to light its streets with gas.

Naturally occurring natural gas was discovered and identified in America as early as 1626 when French explorers discovered natives igniting gases that were seeping into and around Lake Erie. In 1821, William Hart dug the first successful natural gas well in the United States in Fredonia, New York. Eventually, the Fredonia Gas Light Company was formed, becoming the first American natural gas distribution company. In 1836, the City of Philadelphia created the first municipally owned natural gas distribution company.

Today, United States public gas systems number more than 900, and Philadelphia Gas Works is the largest and longest operating public gas system in the United States. During most of the 19th century, natural gas was used almost exclusively as a source of light, but, in 1885, Robert Bunsen's invention of what is now known as the Bunsen burner opened vast new opportunities to use natural gas.

Once effective pipelines began being built in the 20th century, the use of natural gas expanded to home heating and cooking, appliances such as water heaters and oven ranges, manufacturing and processing plants, and boilers to generate electricity (AGA).

GATHERING SYSTEMS

Gathering systems move natural gas from the wellhead to either a processing or storage facility. The system generally consists of small-diameter pipelines running at low pressures.

A gathering system may need one or more field compressors to move the gas to the processing facility. A compressor is a machine driven by an internal combustion engine or turbine that creates pressure to push the gas through the lines. Most compressors in the natural gas delivery system use a small amount of natural gas from their own lines as fuel.

Raw natural gas, sometimes referred to as "sour gas", may contain high concentrations of corrosive constituents (i.e. sulfur, carbon dioxide, liquids/water, etc.). Because of this, the pipe materials used within gathering systems are specially selected to ensure safety and longevity. The transport of sour gas to the "sweetening plant" (part of the overall processing facility) must be done very carefully.

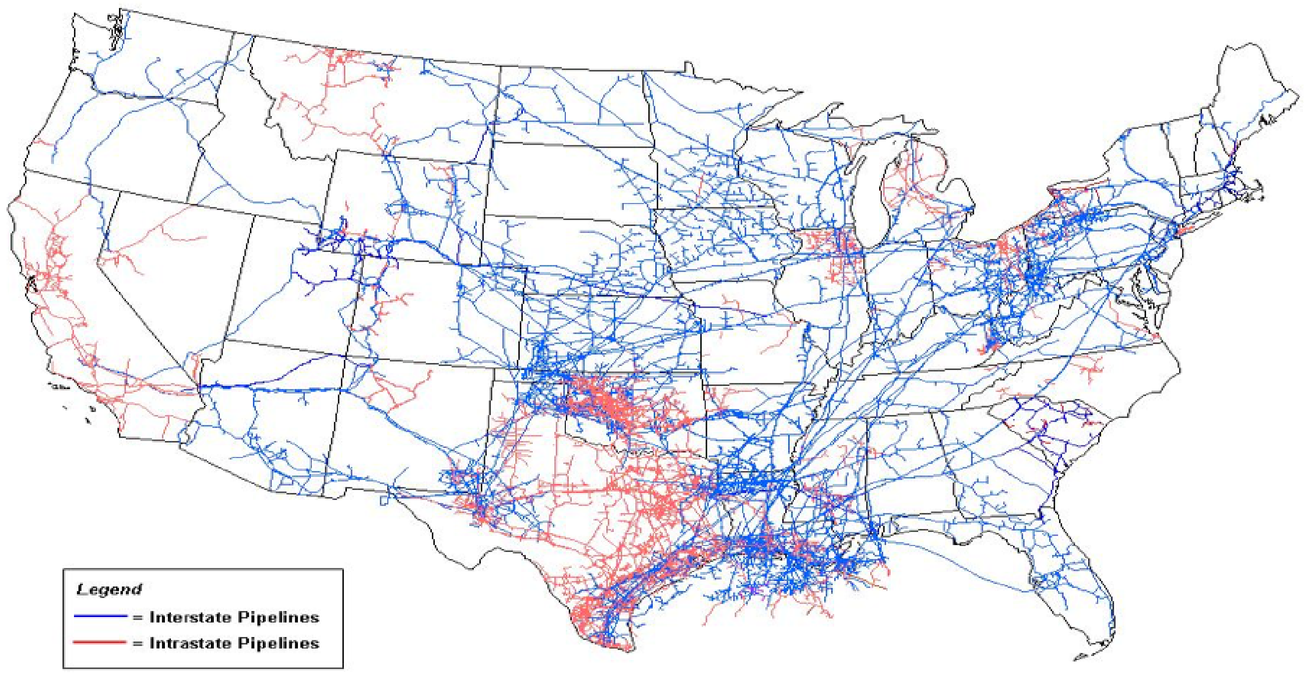
Processing facilities remove potentially corrosive impurities and inert gases, such as helium, which would reduce the energy value of the gas. Processing facilities can also remove small quantities of propane and butane. These gases are used for chemical feed-stocks and other applications (AGA).

TRANSMISSION SYSTEMS

From the gathering system, the natural gas moves into the transmission system, which is composed of about 272,000 miles of high-strength steel pipe ranging from 20 inches to 42 inches in diameter.

These large transmission lines for natural gas can be compared to the nation's interstate highway system for cars. They move large amounts of natural gas thousands of miles from the producing regions to LDCs. The pressure of gas in each section of line typically ranges from 200 pounds to 1,500 pounds per square inch, depending on the type of area in which the pipeline is operating. As a safety measure, pipelines are designed and constructed to handle much more pressure than is ever actually reached in the system. For example, pipelines in more populated areas operate at less than one-half of their design pressure level.

Many major interstate pipelines are "looped", meaning there are two or more lines running parallel to each other in the same right-of-way (ROW). This provides maximum capacity during periods of peak demand. The pipeline rights of way are usually 100 feet wide and are leased from landowners with restrictions on construction activities to minimize the potential for accidental damage (AGA).



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

COMPRESSOR STATIONS

Compressor stations are located approximately every 50 to 60 miles along each pipeline to boost the pressure that is lost through the friction of the natural gas moving through the steel pipe. Many compressor stations are completely automated, so the equipment can be started or stopped from a pipeline's central control room. The control room also can remotely operate shut-off valves along the transmission system. The operators of the system keep detailed operating data on each compressor station, and continuously adjust the mix of engines that are running to maximize efficiency and safety.

Natural gas moves through the transmission system at up to 30 miles per hour, so it takes several days for gas from Texas to arrive at a utility receipt point in the Northeast. Along the way, there are many interconnections with other pipelines and other utility systems, which offer system operators a great deal of flexibility in moving gas (AGA).

LINEPACK

A 50-mile section of 42-inch transmission line operating at about 1,000 pounds of pressure contains about 200 million cubic feet of gas -- enough to power a kitchen range for more than 2,000 years. The amount of gas in the pipe is called the "linepack."

By raising and lowering the pressure on any pipeline segment, a pipeline company can use the segment to store gas during periods when there is less demand at the end of the pipeline. Using linepack in this way allows pipeline operators to handle hourly fluctuations in demand very efficiently.

Natural gas pipelines and utilities use very sophisticated computer models of customer demand for natural gas, which relay daily and hourly consumption trends with seasonal and environmental factors. That's why customers can depend on the reliability of natural gas: when it's needed, it's there (AGA).

GATE STATIONS

When the natural gas in a transmission pipeline reaches a local gas utility, it normally passes through a gate station. Utilities frequently have gate stations receiving gas at many different locations and from several different pipelines. Gate stations serve three purposes. First, they reduce the pressure in the line from transmission levels (200 pounds to 1,500 pounds) to distribution levels, which range from ¼ pound to 200 pounds. Then an odorant, the distinctive sour scent associated with natural gas, is added, so that consumers can smell even small quantities of gas. Finally the gate station measures the flow rate of the gas to determine the amount being received by the utility (AGA).

THE DISTRIBUTION SYSTEM

From the gate station, natural gas moves into distribution lines, or mains, that range from two inches to more than 24 inches in diameter. Within each distribution system, there are sections that operate at different pressures, with regulators controlling the pressure. Some regulators are remotely controlled by the utility to change pressures in parts of the system to optimize efficiency. Generally speaking, the closer natural gas gets to a customer, the smaller the pipe diameter is and the lower the pressure is.

The gas utility's control room continuously monitors flow rates and pressures at various points in its system. The operators must ensure that the gas reaches each customer with sufficient flow rate and pressure to fuel equipment and appliances. They also ensure that the pressures stay below the maximum pressure for each segment of the system. Distribution lines typically operate at less than one-fifth of their design pressure.

As gas flows through the system, regulators control the flow from higher to lower pressures. If a regulator senses that the pressure has dropped below a set point, it will open accordingly to allow more gas to flow. Conversely, when pressure rises above a set point, the regulator will close to adjust. As an added safety feature, relief valves are installed on pipelines to vent gas harmlessly, if a line becomes overpressured and the regulators malfunction.

Sophisticated computer programs are used to evaluate the delivery capacity of the network and to ensure that all customers receive adequate supplies of gas at or above the minimum pressure level required by their gas appliances.

Distribution mains are interconnected in multiple grid patterns with strategically located shut-off valves so the utility can perform maintenance of its lines without ever shutting off a customer (AGA).

MOVING NATURAL GAS INTO THE HOME

Natural gas runs from the main into a home or business in what's called a service line. Today, this line is likely to be a small-diameter PE line an inch or less in diameter, with gas generally flowing at a pressure range of 15-60 psig.

When the gas passes through a customer's gas meter, it becomes the property of the customer. Once inside the home, gas travels to equipment and appliances through piping installed by the home builder and owned by the customer, who is responsible for its upkeep.

Most gas meters are connected to an inner or outer wall of a home or business. In some instances, however, meters are located next to the point where the service line meets the main line. In this case, the piping from the meter to the structure is the customer's property, not the gas company's. These are called "customer-owned" lines and their maintenance is the responsibility of the customer.

When the gas reaches a customer's meter, it passes through another regulator to reduce its pressure typically to ¼ psig (7” w.c.) to 2 psig. (NOTE: Some service lines carry gas that is already at these very low pressures.) There will also be an additional appliance regulator (customer-owned) further reducing pressure to 3-3.5” w.c.. This is less than the pressure created by a child blowing bubbles through a straw in a glass of milk.

When a gas furnace or stove is turned on, the gas pressure is slightly higher than the air pressure, so the gas flows out of the burner and ignites in its familiar clean blue flame (AGA).

SECTION TWO

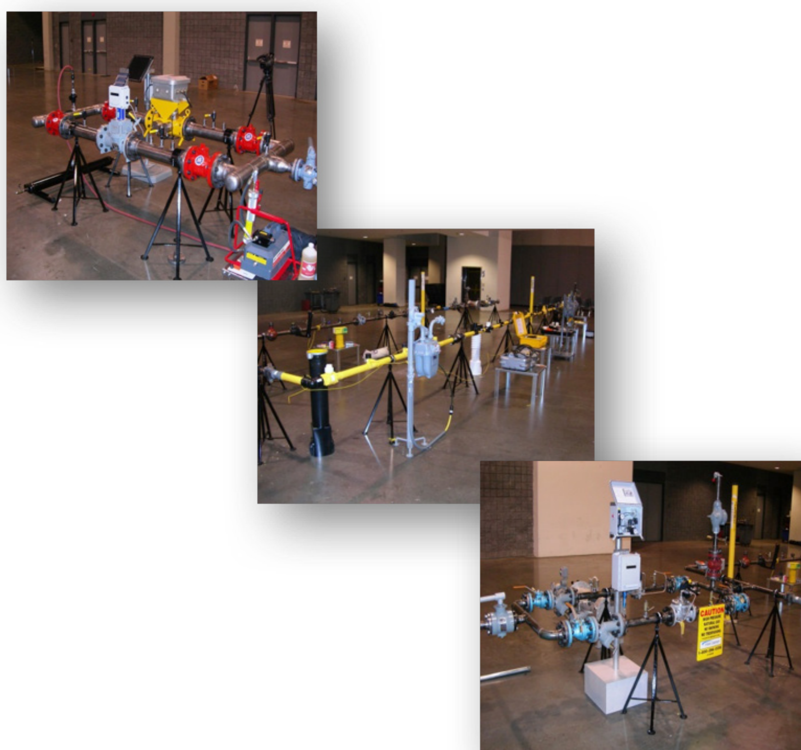
THE COMPONENTS OF A NATURAL GAS TRANSMISSION AND DISTRIBUTION SYSTEM

OVERVIEW

In Section I, “How does the Natural Gas delivery system work”, a general overview of the natural gas grid was provided. The next section primarily focuses on or relates to the gas carrying components of transmission and distribution systems. The intent is to provide high-level answers to 1) what the component is, 2) where the component is used and, 3) why the component is used. Efforts have been made to provide pictures (or videos embedded within the accompanying presentation) showing general appearance and/or functionality.

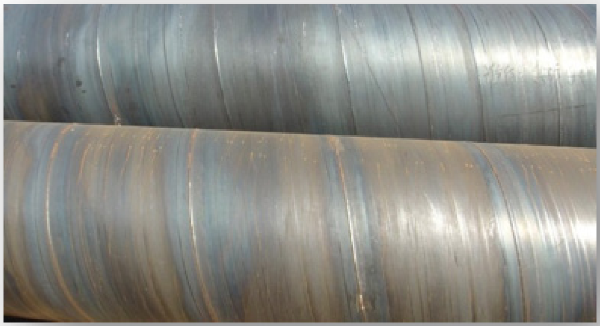
Having been designed to provide a basic overview of each component, Section II is specifically useful to personnel who must handle a myriad of products on a daily basis. It may also be useful to any personnel new to the natural gas industry – Engineers, Operators, Regulatory Compliance Managers, Technicians, etc. – or to those moving to a new position/area of focus.
Examples to be reviewed in this section are:

- **Pipe – Steel**
- **Pipe – Coatings**
- **Pipe – SMYS & Hydrotesting**
- **Pipe – Polyethylene**
- **Fittings – Steel & Polyethylene**
- **Valves**
- **Meters**
- **Regulators**
- **Meter & Regulator Sets**
- **Stations – M&R, Gate, Border**
- **Gas Instrumentation**
- **Filters/Strainers & Gas Conditioners**
- **Odorizers**
- **Leak Survey**
- **Launchers /Receivers**
- **Horizontal Directional Drilling**
- **Tapping & Stopping**
- **Purging Pigging**
- **Cathodic Protection**
- **AC Mitigation**



STEEL PIPE

Generally, there are five techniques for manufacturing steel pipe: fusion weld, seamless pipe, electronic resistance welded (ERW), double submerged arc weld (DSAW), and spiral weld.



Fusion Weld is formed by rolling steel strips through a series of grooved rollers that mold the material into a circular shape, then welding the seam in a continuous weld.

Seamless Pipe is manufactured using a process that heats and molds a solid billet into a cylindrical shape and then rolls it until it is stretched and hollowed. Since the hollowed center is irregularly shaped, a bullet-shaped piercer point is pushed through the middle of the billet as it is being rolled.

Electric Resistance Welded (ERW) pipe is manufactured by cold-forming a sheet of steel into a cylindrical shape. Current is then passed between the two edges of the steel to heat the steel to a point at which the edges are forced together to form a bond without the use of welding filler material.

Double Submerged Arc Weld (DSAW) pipe is rolled cylindrically so that V-shaped grooves are formed on the interior and exterior surfaces at the location of the seam. The pipe seam is then welded by a single pass of an arc welder submerged in flux on the interior and exterior surfaces.

Spiral Weld pipe has a double submerged arc weld (DSAW) seam for the entire length of the pipe in spiral form. The outside-diameter is determined by the angle of the de-coiled steel against the forming head. The more acute the angle, the greater the diameter.

What is the Functional Purpose of Steel Pipe?
Steel pipe is used primarily in high pressure distribution systems (greater than 100 psi), transmission systems, and above ground appurtenances (meter and regulator station, launching/receiving facilities, etc.). Polyethylene pipe is not allowed on above ground installations unless protected against deterioration and external damage (sunlight). Steel pipe must be specified to meet design requirements and must account for class location, SMYS, CP/AC mitigation, testing, and construction methods.

Steel pipe is cut to length of approximately 20 feet at the manufacturer. Typically "random" lengths are used to increase efficiency. Double and triple random are common order lengths being approximately 40 feet and 60 feet. Steel pipe diameters typically range from 2" to 60" with standard wall thicknesses from 0.154" W.T. to 1.0" W.T.

Steel pipe is produced in different yield strengths. X-42 pipe refers to yield strength of 42,000 PSI. A higher yield strength pipe with a thinner wall thickness can equal or exceed a design pressure of a lesser grade pipe with a heavier wall thickness. During construction, steel pipe is frequently strung-up beside the ditch prior to being lowered or pulled into place.

PIPE COATING

Why Coat Pipe?

Pipes are coated for physical protection and to prevent corrosion on the pipes over time. Steel pipeline is typically coated with FBE (fusion bonded epoxy), ARO (abrasion resistance overlay)/powercrete, or concrete coating, each having its own specific purpose in pipeline protection. The primary purpose of FBE is to provide corrosion protection for the steel pipe. Powercrete/ARO provides protection of FBE during construction, and concrete coating is used for buoyancy control in wetland, stream, and high water table areas. Station or facilities applications (above ground) will be painted to match system requirements.

Types of coatings:

- **Bituminous Asphalt Steel Pipe Coating** (Fast and least expensive)
- **Coal Tar / Epoxy Coating** (Typically applied in two coats, 16 mil minimum)

- **Powder Coating and Multi-Coat Exterior Paint Systems** – Epoxy – (FBE) There are two main categories of powder coatings: thermosets and thermoplastics. The thermosetting variety incorporates a cross-linker into the formulation. When the powder is baked, it reacts with other chemical groups in the powder to polymerize, improving the performance properties. The thermoplastic variety does not undergo any additional actions during the baking process, but rather only flows out into the final coating. The most common polymers used are polyester, polyurethane, polyester-epoxy (known as hybrid), straight epoxy (fusion bonded epoxy) and acrylics.

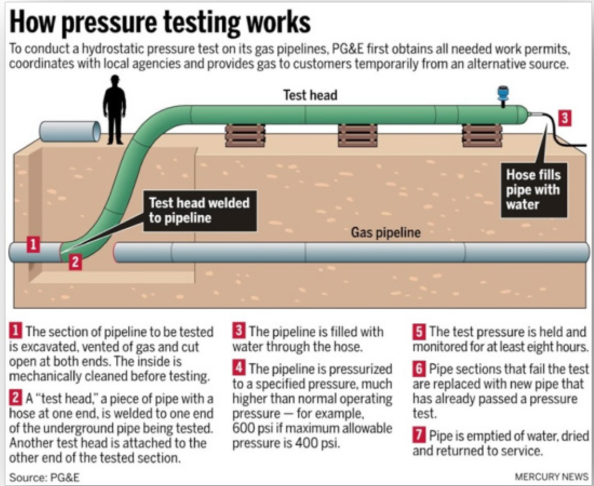
Corrosion Trade Groups

- The National Association of Pipe Coating Applicators (NAPCA)
- National Association of Corrosion Engineers (NACE)

PIPE SMYS AND HYDROTESTING

What are Pipe SMYS and Hydrotesting?

Specified Minimum Yield Strength (SMYS) is most frequently reported as a percentage of the maximum allowable pressure by the manufacturer. Testing involves qualifying the materials as constructed to test and document the abilities of a system to deliver product and the pressure designed. Testing may be performed hydrostatically or by using nitrogen or inert gas. Hydrotesting involves filling the pipe/components with water then pressurizing the system to the desired test pressure and maintaining this pressure for a specified time. Water will not change volume with increased pressure. If air alone was used as the test media, it could take a considerable time to increase the pipeline's volume to the desired test pressure.



What is the Functional Purpose of SMYS and Hydrotesting?

The purpose of establishing SMYS is to create a baseline on which varying materials and conditions can be evaluated and designed around. SMYS can range from 0% SMYS up to 72% SMYS as a maximum allowable operating pressure (MAOP). SMYS is used to incorporate design constraints and material limitations into a system design.

While the pipe and the individual components may have been pressure tested by the manufacturer, the welds joining the components must be tested after construction. The purpose of testing is to qualify materials, workmanship, and design to a direct test to confirm the system can deliver as intended.

TEST SPECIFICATIONS

DATE	SELECT ROUTING	TEST NUMBER	OF
TBD		1	1

PROJECT NAME	AFE	FACILITY NAME or NUMBER
Example Project		10.123456

INSTALLATION LOCATION				COUNTY, STATE	CLASS LOCATION	PLANNED MAOP	DESIGN PRESSURE	DESIGN TEMP. RANGE
FROM:	251+00	TO:	584+93	DECATUR, AL	3	150 psig	740 psig	-20 F to 120 F

150

33.393 LF OF 6" REPLACEMENT STEEL

** NO VALVES OR FITTINGS ARE TO BE TESTED FOR THIS HYDROTEST. ALL VALVES AND FITTINGS SHALL BE CUT IN AND X-RAY INSPECTED UPON SUCCESSFUL PRESSURE TESTING OF THE PROPOSED 6" PIPELINE.**

TEST TYPE	REASON FOR TEST	PRE/POST INSTALLATION TEST
Strength	New Construction	☐ Pre ☑ Post

TEST DESIGN CRITERIA

Minimum Component Characteristics

Limiting Valve/Flange Class Rating: ASME/ANSI CLASS 600

Pipe Information	Limiting Specs.
O.D.	6.625
Wall Thickness:	0.280
SMYS:	52,000

Test Design Calculation

☑ Input minimum and maximum pressure of test
☐ Input minimum and maximum % SMYS of test

Description	Pressure (psig)	% Pipe SMYS
Min. Test Pressure (at high elevation):	1,120	25.5%
Max. Test Pressure (Pipe):	1,350	30.7%
Max. Test Pressure (Valve & Fittings):	2,225	50.6%

TEST SECTION (Reference Data)

Test Medium:	Water (Fresh)	
Test Duration:	8	Hours (min)
Section Length:	33,393	Ft.
Section Fill Volume:	51,118	Gal.
Max. Elevation Change:	269	Ft.

Station Equations	1	2	3
Back:			
Ahead:			

FIELD TEST PRESSURE REQUIREMENTS

Location	Station	Elevation (feet)	Max. psig.	% SMYS @ Max.	Min. psig.	% SMYS @ Min.	Variance psig.	Target psig.	% SMYS @Target
BEGIN	251+00.0	403	1,350	30.7%	1,237	28.1%	113	1,293	29.4%
HIGH ELEVATION	461+84.0	672	1,232	28.0%	1,120	25.5%	112	1,176	26.8%
LOW ELEVATION	251+00.0	403	1,350	30.7%	1,237	28.1%	113	1,293	29.4%
END	584+93.0	606	1,261	28.7%	1,149	26.1%	112	1,205	27.4%
Dead Weight Location (Test Point)	584+93.0	606	1,261	28.7%	1,149	26.1%	112	1,205	27.4%

REMARKS

Assumed Dead Weight Location: 584+93 (Test Point)
Target Test Pressure (at test point) = 1205 psig
Min Test Pressure (at test point) = 1149 psig (bleed as necessary)
Max Test Pressure (at test point) = 1261 psig (bleed as necessary)

Test duration is 8 hours after pressure has stabilized, or as directed in the SOW.

PRE-TEST SPECIFIED / REVIEWED BY:		TEST PERFORMED / ACCEPTED BY:		POST-TEST REVIEWED BY:	
Originator (Signature)	Date:	Test Performed by (Signature):	Date:	Compliance (signature)	Date:
Design Review if applicable (Signature)	Date:	Company Name (for Contractor or for Employee):	Date:	Engineering / Operations Manager (Signature)	Date:
Compliance (Signature)	Date:	Witnessed & Accepted by AGL Representative (Signature):	Date:	Actual MAOP	

Where are SMYS and Hydrotesting Found Along the Grid?

SMYS is a function of all steel components within a system. All components (steel and PE) should meet the testing requirements of the appropriate regulations.

A	B	C	D	E
Input:				
S = Yield Strength (psig)		65,000		**192.107:** Yield Strength
D = Nominal Diameter (inches)		24.000		
t = Nominal Wall Thickness (inches)		0.344		
F = Design Factor (Class Location Factor)		0.40		**192.111:** Class 1 = 0.72, Class 2 = 0.60, Class 3 = 0.50, Class 4 = 0.40
E = Longitudinal Joint Factor		1.00		**192.113:** For API-5L Seamless, ERW, Electric Flash Welded, SAW = 1.00, Furnace Butt Welded = 0.60
T = Temperature Derating Factor		1.00		**192.115:** 250° F or less = 1.000, 300° F = 0.967, 350° F = 0.933, 400° F = 0.900, 450° F = 0.867
Required MAOP (psig)		720		
Results:				
P = Design Pressure (psig)		745.33		**192.105:** Design Pressure for Steel Pipe
SMYS = Specified Minimum Yield Strength		1863.33		
% of SMYS		38.64		
Is This Pipe Specification Acceptable?		YES		

POLYETHYLENE PIPE

History

Polyethylene (PE) pipe was considered for use in the natural gas industry as early as 1954 when a special committee of the Thermoplastic Pipe Division of the Society of Plastic Pipe recommended the first three thermoplastic materials for natural gas distribution pipe.

By 1965, cumulative miles of PE pipe had reached over 9,000 miles. By the 1970's PE pipe was gaining in popularity primarily due to ease of installation and cost, both large factors in PE's success. Currently PE pipe is used extensively in the natural gas industry.

What Does it Look Like?

Typically in distribution systems, PE pipe will be found in two colors, solid yellow or black with yellow stripes. Medium Density (MD) pipe, which is typically rated for up to 80 psi applications, will be found in solid yellow color. High Density (HD) pipe, which is typically rated for up to 125 psi applications, will be found in black with yellow stripes. PE pipe carries two classifications, one of which is a PE number. MD pipe will carry a PE2708 classification, while HD pipe will carry a PE4710 classification. Other classes may also be available, but these are the two typically found in a distribution system. PE pipe also carries an SDR number. SDR is the Standard Dimensional Ratio of the pipe. The SDR number designates the ratio of the diameter of the pipe to the wall thickness. For instance, a smaller diameter pipe may have an SDR number of 11, which means the diameter of the pipe is 11 times the wall thickness. For instance, in the case of a 2" IPS pipe, the wall thickness is .216 and the SDR is 11. When the wall thickness (.216) is multiplied by 11, the resulting outer diameter is 2.375 with a pressure rating of 80 PSI. In contrast, a 1 1/4" IPS pipe, with a wall thickness of .166, yields an outer diameter of 1.66 and a pressure rating of 89 PSI with an SDR of 10. The lower the SDR number, the higher the pressure rating as can be seen in the table below. Note pressure ratings at various SDR numbers.

PE pipe can be purchased in either coils of varying lengths, depending on the pipe diameter, or in straight lengths of 40 feet typically in the larger diameter pipes. The chart on the right shows typical packaging options for ½ to 2" IPS PE pipe.

Size	Length	Standard Coil Size ID-OD-W	Standard Pallet Size	Standard Coil Per Pallet	Feet Per Pallet	Pallets Per 48' Truck	Feet Per 48' Truck
½"	500	30-44-6	44	14	7,000	26	182,000
	1,000	30-44-10 ¼	44	7	7,000	26	182,000
¾"	150	30-37-6 7/8	44	12	1,800'	26	46,800'
	250	30-41-5 ½	44	14	3,500	26	91,000
	500	30-44-10	44	7	3,500	26	91,000
1"	150	32-41-6	44	12	1,800	26	46,800
	250	30-43-7 ¾	44	11	2,750	26	71,500
	500	30-44-12	44	6	3,000	26	78,000
	1,000	48-71-9 ½	78	10	10,000	7	70,000
1 ¼"	150	32-44-7 ½	44	10	1,500	26	39,000
	250	48-63-7	67	12	3,000	8	24,000
	500	48-72-7 ½	78	12	6,000	7	42,000
	1,000	48-74-12 ¾	78	7	7,000	7	49,000
	1,500	48-76-21	78	4	6,000	7	42,000
1 ½"	250	45-65 ¼-7 1/2	67	10	2,500	8	20,000
	500	48-75-8 ½	78	8	4,000	7	28,000
	1,000	48-75-16 ½	78	5	5,000	7	35,000
	1,500	48-81-18 ½	96	4	6,000	7	42,000
2"	150'	50-69-7.3/8	78	12	1,800'	7	12,600'
	250	54-74-8	78	10	2,500	7	17,500
	350	52-77-9 ¾	78	8	2,800	7	19,600
	500	52-78-13	78	7	3,500	7	24,500
	600	52-81-13 3/8	78	6	3,600	7	25,200
	1,000	48-73-28	78	3	3,000	7	21,000
	1,500	51 1/2-76-38	78	2	3,000	7	21,000
	2,000	52-77 3/8-50	78	2	4,000	7	28,000

What is the Functional Purpose of Polyethylene Pipe?

PE pipe is used primarily in distribution systems as it can only be installed underground. Above ground use of PE pipe is prohibited by federal regulations. Also, due to pressure limitations at 125 PSI max, PE is designed for distribution applications where higher pressures are not required as opposed to higher pressure rated steel pipe. PE pipe also eliminates the requirement for corrosion control methods seen in steel pipe systems.

Where is Polyethylene Found Along the Grid?

PE will typically be found on the downstream side of a distribution system from gate regulator stations. Pressure is typically reduced to a level applicable to the lower pressures required by PE.

FITTINGS (STEEL & POLYETHYLENE)

What Do They Look Like?

Fittings for both steel and PE pipe come in a variety of shapes and sizes to accommodate different straight connections and angled connections. Fittings come in a range of sizes from 1/2" copper tube size to over 36" iron pipe size.

Below is a list of typical fittings commonly found on both steel and PE pipe:

- 90˚ elbows (short radius and long radius)
- 45˚ elbows
- Tees
- Couplings (both straight and reducing)
- Unions
- Cross
- Caps
- Plugs
- Nipples
- Compression fittings

There are other types of fittings, but these are the most common found in distribution systems.

Also found in pipe fittings are tapping tees, which are installed on the main pipeline, be it PE or steel, to provide a tap for service lines to commercial/residential buildings or even on a Transmission pipeline for various applications, such as performing repairs. On steel pipe, these fittings are normally welded to the pipe and then tapped to provide service to a commercial or residential customer. In the case of PE, these fittings are fused on by means such as electrofusion.

What is Their Functional Purpose?

The functional purposes of fittings are as varied as the fittings themselves, but the primary purpose is either to join pipe, change the direction of pipe, or provide a means of delivering gas from the pipe to an end user.

Also, in the case of some fittings, such as the long radius 90˚ elbows, not only does the fitting provide a means for change in direction, but it also provides a means to accommodate "pigging" a pipeline. Although pigging is covered in another segment of this presentation, the design of certain pigs require a longer radius elbow in order for the pig to make a turn in the pipe without being hung up at an elbow juncture.

Functions of Specific Fittings:

Tapping tees provide a means of transitioning gas from a main to a customer.

Reducing fittings provide a means of transitioning from pipes of different diameters.

Unions provide a means of being able to remove portions of a pipe without having to cut the pipe.

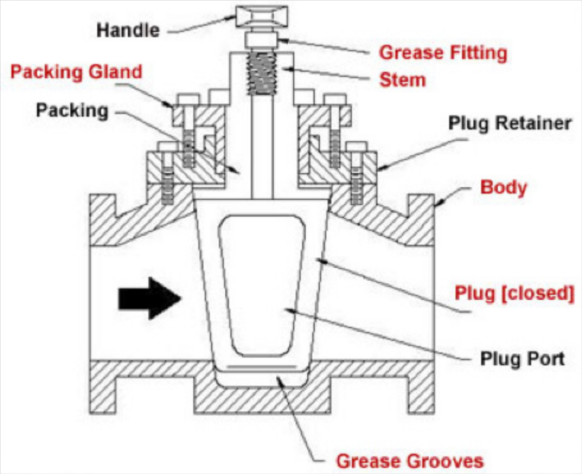
Transition fittings enable transition from steel to PE pipe.

Compression fittings (such as compression couplings) join or repair steel pipes or connect PE pipes.

Where are These Components on the Grid?

Fittings are found from the wellhead to gathering lines, transmission lines, distribution mains, customer service lines, and customer piping lines within buildings. Without these fittings, there would be no means to get the gas from the wellhead to the "burner tip". They are a critical component in the natural gas grid.

VALVES



Since the ancient times, people understood how to regulate water with either stones, branches or tree trunks. Common practice involved cracking holes in pipes and then inserting a branch with a stone affixed using leather to divert or stop flow. The crack was stuffed or packed with mud, clay or cloth to prevent escape of the water. These basic components and terms are still common to valves today

Basics Parts of Valves:

- Body
- Bonnet
- Ports
- Stem
- Packing
- Seat
- Controlling Element (Ball, Gate, Plug, Disc, Wafer, Globe, Wedge, Check)
- Actuator/Operator

Mesopotamians, Egyptians, Greeks, and other cultures were able to drive water from rivers and springs for public use or irrigation using valves. However, the Romans were the true developers of valves due to their elaborate canal systems. The valves used were plug or stopcock type made of bronze. This material was well known by the master of the “Collegia Fabrorum”. It was rich in lead, anti-corrosive, ductile, and able to weld to the pipes of bronze or lead. It also had good non-frictional properties, which facilitated the rotation of the plug.

The parts of the valve were a body, a holed plug, a bottom, packing, and a long stem for turning the plug. Sometimes a pin was forced with a hammer into the valve, which allowed for the plug to turn but not be removed. This practice was a way to prevent people from removing the plug and stealing water.

The Romans’ ingenuity was shown throughout small Mediterranean towns where various types of valves have been found, including butterfly, cylindrical plug, angular, and check (to prevent back flow). The Romans even developed a primitive diaphragm valve made of crude leather that was manually closed over a weir to control flow and temperature of household bath water – essentially a mixing valve.

Valves are essentially for system control – most commonly used for turning service on and off. Valves used for this purpose are usually referred to as block valves. Valves are strategically placed to be utilized in the event of emergency or for diverting flow.

Valves can be found above or below the surface. Operators (i.e. square heads, levers, handwheels, gear operators, actuators, extensions) are common to both regardless of whether they are above or below the surface. Valves can be operated manually through torque reduction gear operators or by power actuators (i.e. electric, pneumatic, hydraulic, media), which can include electronics to allow for remote control. An analogy on operators could be a garage door, which can be lifted by hand (manual), with a motor control button at the door (gear operator), or a motor with a handheld/car remote (actuator).

Valves in natural gas are generally made of steel (forge & cast), PE, or cast iron. A wide range of sizes are used in the natural gas industry from ¼” to 50”.

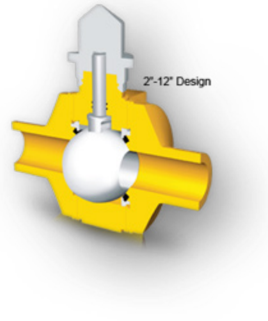
Types of Valves:
- Ball (Trunnion, Floating, Quarter-Turn, Multi-Turn)
- Gate (Rising and Non-Rising Stem, Wedge, Slab)
- Plug
- Check
- Wafer/Butterfly
- Globe
- Manifold
- Disc
- Control /Regulating
- Relief

STEEL VALVES PLUG-GATE-BALL





POLYETHYLENE VALVES



METERS

The purpose of gas meters is to measure the amount of gas passing through a pipeline. Gas meters are present at all points of custody transfer, or the location where gas changes ownership, for billing purposes. Gas meters are essentially considered to be the "cash registers" of the natural gas industry. Traditionally, custody transfers take place between producer to transmission, transmission to distribution, and distribution to end-user.

Deregulation and open access in the United States natural gas industry in the late 1990's built a competitive market, motivating more efficient company operations. Gas companies are facing constant pressure to earn greater profits and cut costs. With many more participants buying and selling gas in the United States marketplace, the accurate measurement of gas at custody transfer points is critical. If there is a bias in the custody transfer meter, that bias penalizes one side of the transaction and thus increases operating costs and hurts the competitive environment.

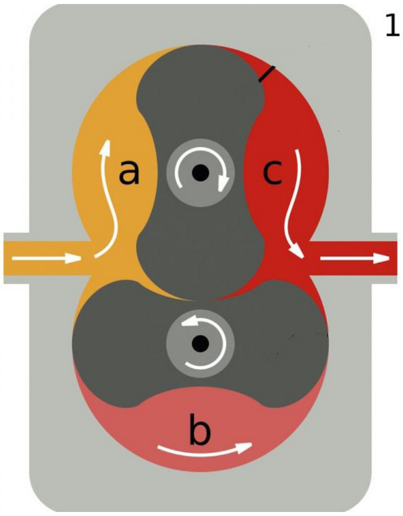
There are various types of gas meters available and used based upon differing application requirements and/or associated advantages and disadvantages. The two general categories of meters are positive displacement and inferential.

Positive Displacement (PD) Meters require fluid to mechanically displace components in the meter to accomplish flow measurement. PD meters measure the volume of gas by dividing the media into fixed, metered "chambers". A basic analogy would be holding a bucket below a tap, filling it to a set level, then quickly replacing it with another bucket and repeating. By counting the number of buckets filled, and applying the appropriate pressure and temperature correction (Basic Gas Laws), the totalized corrected volume can be accurately determined.

There are two types of PD meters commonly used for measuring natural gas : diaphragm and rotary. Diaphragm meter sizes make them suitable for use from residential up through small commercial/ industrial applications. Rotary meter sizes range from small commercial/industrial to transmission.

DIAPHRAGM METERS

ROTARY METERS



Inferential Meters determine volume by measurement of a phenomenon associated with the flow, or worded differently, they infer volumetric flow rate by measuring a property of the flow stream. The three most commonly used inferential meters used in the natural gas industry are turbine, orifice and ultrasonic meters. In general, these meters are designed for medium to high volume and/or pressure applications ranging from small industrial to transmission.

Turbine meters use a rotating rotor to measure gas velocity and, through a series of gears, infer that to specific volumes. Orifice meters infer the volumetric flow by measuring pressure drop over an obstruction (orifice plate) inserted in the pipe. Ultrasonic meters measure the difference in transit time of sonic pulses that travel to and from upstream and downstream transducers.

Regardless of the type, manufacturers test meters for both pressure integrity and accuracy. Pressure testing is done in accordance with ANSI requirements, which is 1.5 times the meter's Maximum Allowable Operating Pressure (MAOP). Accuracy testing ("proof"), may be done at several different flow rates and/or, if specified, at elevated pressures. For extremely high-volume applications, meters may be tested by a third-party.

TURBINE METERS

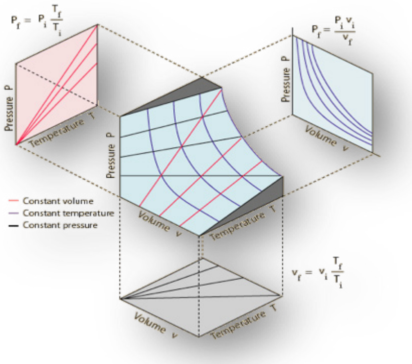
Criteria used for the sizing and selection of meters are the required flow rate and pressure rating. It's common for meters to be sized with a safety factor to allow for future growth and to ensure longevity of the product. Since there is overlap between meter types with regards to the applications they can be used, there are instances in which multiple meter types could be used. In these cases, characteristics associated with the meter types, as well as advantages and/or disadvantages are considered. Some of these considerations include, but are not limited to, design complexity, rangeability, physical size/footprint (of meter), physical size/footprint (of station), flow conditioning requirements, installation/maintenance requirements, etc.

GAS INSTRUMENTS

"Instruments" is somewhat of a broad term when considering all the mechanical and/or electronic instrumentation used in the natural gas industry. For the purposes of GAS 101, we will limit this term to equipment used to monitor and/or correct for pressure and temperature variations, as well as apply the appropriate compressibility factor (Basic Gas Laws).

Unlike a solid or fluid, gas is highly compressible based upon pressure and temperature. Measuring gas can be quite complex and is often referred to as the "elusive cubic foot". The meters outlined in the previous section do not take these variations into account by themselves – they require a "Corrector" to convert the meter's uncorrected reading to a corrected reading. The corrected reading is determined by multiplying and applying factors from the Basic Gas Laws and a compressibility factor (if required). The Basic Gas Laws are made up of the following:

Boyles' Law the volume of a given mass of a gas is inversely proportional to its pressure provided the temperature remains constant



Charles' Law for a given mass of an ideal gas at constant pressure, the volume is directly proportional to its absolute temperature

Ideal Gas Law the equation of state of an ideal gas, which is a theoretical gas composed of many randomly moving point particles whose only interactions are perfectly elastic collisions

Real Gas Law real gases are non-hypothetical gases whose molecules occupy space and have interactions; consequently, they adhere to gas laws. However, due to the molecules' interactions with one another, the effects of compressibility need to be accounted for

Measurement Gas Law applies the real gas law to the meter's uncorrected meter reading

Development of instruments to convert a meter's uncorrected volume to corrected volume has been driven by the industry's continuous desire for improved measurement accuracy. Manufacturers serving the natural gas industry first set out to design such devices in the 1950's. These early instruments were initially standalone full scallop mechanical chart recorders, which recorded pressure and/or temperature on a time-based rotating chart. The data retrieved from these charts could then be used for billing purposes at base conditions. Further development of this technology led to integration of these devices to meters (mechanically coupling them) to output the corrected volume. Although less common today, mechanical chart recorders are still in use to monitor and document system pressures and temperatures. A common application for a mechanical pressure recorder is for hydro testing pipe.

In the 1980's, manufacturers introduced electronic volume correctors (EVC's), also known as electronic flow computers (EFC's). These instruments were essentially computers housed in enclosures that could be mounted outdoors near or mechanically coupled to meters. In addition to real-time correction for variations in pressure and temperature, these new electronic devices also were capable of performing gas compressibility calculations. The corrected volume could be read by a meter reader from an LCD.

Further development of these instruments included the capability of storing data (audit trail) that could be downloaded and saved electronically. Although an electronic corrector's primary function continues to be to calculate corrected volumes, today's instruments are now critical components to many gas measurement systems by interfacing with automated meter reading (AMR) and automated meter interface (AMI) systems. Likewise, electronic chart recorders are used to data log system pressures and/or temperatures, which can be communicated on a nearly real-time basis to a utility's data collection system or Supervisory Control and Data Acquisition (SCADA).

As the communications industry has advanced from land line modems to wireless technology, manufacturers producing instruments for the natural gas industry have followed suit with inclusion of these capabilities

REGULATORS

The primary purpose of a gas regulator is to reduce pressure to suitable/safe levels for the downstream piping system while maintaining a sufficient gas supply to meet demand. All natural gas distribution systems have a MAOP. Federal guidelines require that pressure in the system not exceed the MAOP plus an additional amount based on the MAOP.

Secondarily, but extremely important, is the regulator's function of providing a means of overpressure and/or underpressure protection. Here again, federal guidelines exist (49 CFR Part 192.195 - 192.201) outlining the minimum pressure protection requirements. These guidelines outline the types of protection required, as well as specifications and performance characteristics that manufacturers' pressure protection devices must adhere to. State, local, or individual LDCs may have more stringent pressure protection requirements.

Gas regulators are predominantly used starting at city gates/take-off stations, where transmission pressures are reduced to suitable levels for distribution, and then throughout the distribution grid at district stations, farm taps, and commercial/industrial and residential applications. In addition, although not the gas company's responsibility, many industrial end-users use gas regulators within their facilities to control pressures for specific processes as well as having "combustion" or appliance regulators on equipment provided by OEMs.

Basic sizing and selection of gas regulators is done on case-by-case basis considering the following:

- Inlet Pressure (minimum & maximum)
- Outlet Pressure
- Required Flow Rate
- Outlet Pressure Accuracy Requirements
- Load Profile
- Pipe Size
- Overpressure and/or Underpressure Protection Requirements

The basic sizing and selection of a gas regulator will determine the model, valve head size, orifice (or restrictor cage) size, and spring range. In addition to this information, the manufacturer will also need information regarding options associated with the specific model being requested. A few of these options are as follows (not a complete list and not applicable to all models):

- Valve Head/Body Type
- Inlet/Outlet Pressure Ports
- Vent Size
- Valve Head & Vent Orientation
- Overpressure and/or Underpressure Set Points
- Flexible Element Material
- Application Type (i.e.: Worker or Monitor)

As noted above, a secondary, but extremely important function of gas regulators is to provide a means (or multiple methods) of overpressure and/or underpressure protection. These functions can be accomplished a number of ways that are integral to the gas regulators such as internal relief, overpressure shut off, underpressure shut off, internal monitor, etc. Further, regulators can be used in conjunction with non-integral pressure protection devices.

There are a number of different types of regulators, such as flexible element (valves), direct-acting, lever-type, pilot-loaded, etc. Within these type categories, the regulators are further broken down by many different options, depending upon manufacturer.

RESIDENTIAL REGULATORS

INDUSTRIAL REGULATORS

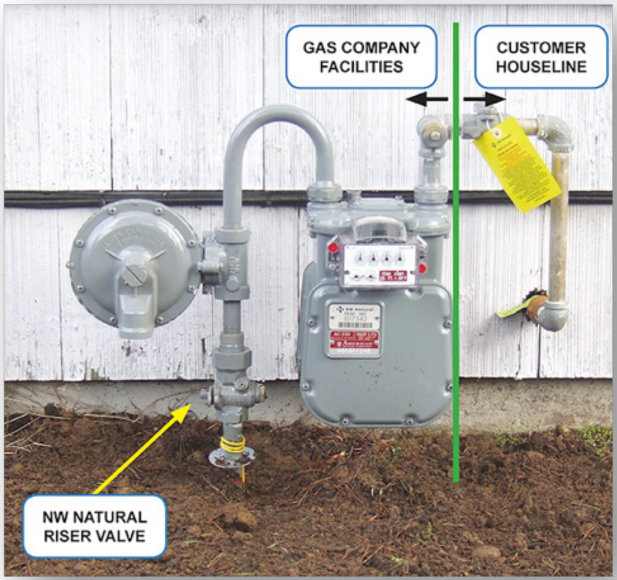
DISTRICT REGULATORS

Regardless of the type and options specified, manufacturers test regulators for pressure integrity in accordance with ANSI requirements, which is 1.5 times the regulator's MAOP. In addition, regulators are tested (set) for outlet pressure and lock-up, as well as set points for overpressure, underpressure, and/or relief if applicable.

METER & REGULATOR SETS

Meter and Regulator (M&R) sets, as opposed to stations mentioned in the next section, are generally considered for residential, commercial or industrial locations. M&R sets, particularly residential, are often seen as the calling card or resume of a gas utility because they are what the general public generally sees as the most recognizable face of a gas utility.

Despite efforts throughout the industry nationally, it seems every LDC feels they have the best design. Because of various circumstances, some M&R sets take on a roller coaster effect with many twists and turns, resulting in an uncertain or odd look. Note the uniformity/standardization in the example below, which is often a fervent desire for many gas utility managers, but often just as elusive as that mysterious cubic foot of gas.



A service line, either steel or PE, is connected or tied on to the main. The service line is (usually) connected to a meter riser, which is basically a transition fitting by using a fusion, weld, or mechanical coupling. This riser serves as a transition from the service line to a meter stop (aka meter valve, meter cock, shut-off valve or wing lock. The meter stops almost always have a method of locking in the open and/or closed position to ensure the general public does not service on/off. The meter stop is connected to a short nipple that is connected to the regulator. It is at this point that the pressure is reduced from system pressure (commonly 45 to 60 psig) to service pressure (commonly 7" w.c. to 2 psig). The outlet from the regulator connected to the gas meter via piping and connections (Swivel, Nut, Washer). The fuel line (customer line) connects to the house piping through a stub out (where the pipe enters the building). All of these components can be individually pieced together (usually threaded) or can be pre-fabbed as essentially one set.

Pre-fab M&R sets utilizing bent pipe (rather than screwed connections), welds, and/or cast meter bars have increasingly become the go-to because of the economic and functional advantages, including the elimination of potential leak paths. From a material management standpoint, utilizing a pre-fab M&R set essentially reduces the many individual components used within the assembly into one outsourced item.

While the industry's trend was initiated on residential (250-class meters) applications, the benefits have been realized over the years and now it's quite common for pre-fab M&R sets to be used on commercial and industrial applications as well (i.e. 400-class, 600-class, 800/1000-class, rotary).

"Prefabbers", which are outsourced manufacturers, combine all/most of the components in factory with qualified welding, forming, joining, and testing. In addition, with increasing emphasis on atmospheric corrosion in the industry, having the M&R sets coated in a controlled environment has shown many benefits.

STATIONS – M&R, GATE, BORDER

When natural gas in a transmission pipeline reaches a local gas utility, it normally passes through a gate station. These points are also commonly referred to as take-off, town border, or tap stations. Utilities frequently have gate stations receiving gas at many different locations and from several different pipelines. The number of gate stations an LDC has is dependent upon the physical size (territory) of the LDC, as well as the required throughput. Gate stations serve three primary purposes: pressure reduction, measurement, and odorization.

First, pressure is reduced from transmission levels (200 PSI to 1,500 PSI) to distribution levels, which range from ¼ to 300 PSI. It should be noted that the pressure control point in some cases may not necessarily be directly downstream of the gate station, but very well could be miles away within the distribution system. In many cases, the pressure reduction is significant enough that it needs to be accomplished in several stages and/or heaters need to be used to prevent freezing.

Then an odorant, the distinctive sour scent associated with natural gas, is added so that the public can smell even small quantities of gas should there be a leak. The responsibility of adding odorant is dependent upon the contract between the transmission company and the LDC's

Finally, the transmission company measures gas to determine the amount being received by the utility (usually a custody transfer point). In some cases, the LDC may opt to install their own meters for validation. These are known as "check" meters.

Many gate stations are covered by a fiberglass enclosure or metal building to protect it from the weather elements, as well as act as a sound abatement. When justified by the size/volume the station is expected to handle, offices with control and/or monitoring instrumentation may also be present.

In terms of "footprint", gate stations range from being very large to reasonably small, depending upon the volume expected through the station. A wide range of equipment is used to construct gate stations, many of which have been covered in previous sections. Therefore, a list of possible gate station equipment is as follows:

- Pipe (Steel)
- Filters/Strainers
- Regulators (High-Pressure Models)
- Heaters
- Valves (Trunnion)
- Odorizors (High-Pressure/Volume or Supplemental)
- Meters (Generally Ultrasonic, Turbine or Occasionally Rotary)
- Instruments (Monitoring and/or Correction)
- Fittings (General Fittings but also Including Insulators)

FILTERS/STRAINERS & GAS CONDITIONERS

The use of natural gas filters and strainers is a preventative measure that transmission companies and LDCs take to avoid damage to or adversely affect performance of downstream equipment.

Strainers are typically used to capture larger debris in the gas stream while dry gas filters and coalescing filters/separators are designed to remove extremely small particles.

Manufacturers use differing methods of documenting the filtration capabilities of the products they provide. Therefore, when comparing the filtration provided by filters and strainers, it's important to understand the terminology used and relationship between the several filtration rating (Mesh and Micron) systems.

Mesh	Micron	Particle Size (Inches)
20	840	0.0328
80	177	0.0069
200	74	0.0029
400	37	0.0015
625	20	0.0008
1250	10	0.0004
2500	5	0.0002

Strainers are available in a wide variety of designs (i.e. gasket, cone, basket, Y-, T-), range in sizes as small as ½" up to very large 24" connections and up to ANSI 600 (1,480 psig) pressure ratings. Available mesh sizes range from 20- to 80-mesh.

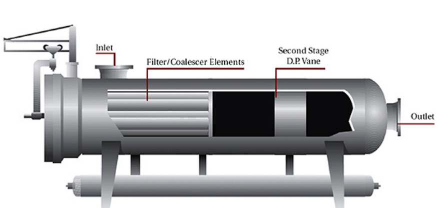
Dry gas filters are designed to remove dirt, rust, pipe scale, iron oxide dust and other particulates from the gas stream. They are available in connections ranging from ¼" (pilot filters) up to custom 36" or larger and pressure ratings up to ANSI 600 or higher. The filter elements used in dry gas filters, which are generally paper or cellulose fiber reinforced by mesh screens, generally have 5-, 10- or 25-micron ratings.

Coalescing filter/separators are used where a high-degree of filtration is necessary to remove particles and liquids. Water, oil, and dirt in natural gas lines at wellheads, upstream of compressors, downstream of compressor aftercoolers, and at compressor fuel gas connections can do great damage to other equipment. Coalescing filter elements (cartridges) are built with layers of borosilicate fiberglass sandwiched into layers of felted polyester media to remove all liquid droplets, fogs, and mists. In addition, these elements remove particulate matter down to 0.3- microns in size.

STRAINERS



FILTERS/FILTER SEPARATORS



ODORIZERS

While being extremely volatile, natural gas is naturally both colorless and odorless. There are three main reasons why natural gas is odorized: public safety, federal regulations requirements, and liability.

In the United States, the catalyst to odorize natural gas came from one of the nation's worst tragedies in school history. On March 18, 1937, a natural gas leak went undetected at the New London School in New London, Texas. At 3:17 in the afternoon, just a few minutes before school was dismissed for the day, the gas ignited and approximately 300 students and teachers perished in a horrible explosion.

As a result of this incident, federal regulations were put in place to protect the public from a tragedy like this ever occurring again. Hence, Title 49 Part 192 section 625 of the Code of Federal Regulations, also known as 49 CFR 192.625, was born. This regulation mandates that, at all times, combustible gases must be detectable at one-fifth the lower explosive limit by a person with a normal sense of smell. Studies showed that odorous chemicals are the best warning agent. Subsequently, chemicals were developed to be injected into gas lines to act as a warning agent. Usually this is Ethanethiol, commonly known as Ethyl Mercaptan.

Various methods of odorization have been developed through the years:

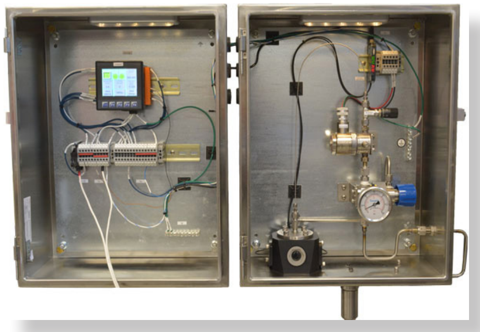
Wick Type Odorizers can be very small, odorizing the gas for as few as one gas customer to much larger systems, such as a small town. They use a wick, which is very similar to those used in a kerosene lantern. The odorant is drawn up the wick from the container and into the gas stream. This method is the simplest and somewhat of a "homemade approach", but is difficult to control the amount of odorant being put into the pipeline.

Absorption Bypass Odorizers take a portion of the gas stream, the amount being dependent on the flow of gas in the line, and run it through a tank containing liquid odorant. The gas is passed over the top of the liquid. Variations exist where wicks are utilized to increase odorant vaporization. This method is more accurate than a wick and latest technology has improved absorption types.

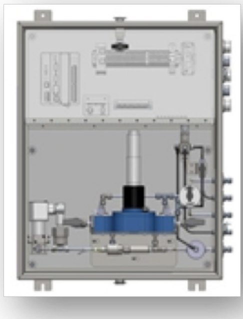
Liquid Injection (Pump) Type Odorizers are generally primary units for mid-volume to very high-volume systems. These odorizers work by utilizing a pump to physically inject small amounts of Ethyl Mercaptan into the moving gas. Various designs of liquid injection (pump) odorizers have been developed through the years to overcome issues encapsulating the entire unit with a pressure vessel to contain any potential leaks through shafts/seals and having the capability to inject the odorant in proportion to the gas flow by using a gas meter to drive the odorant pump.

The latest liquid injection type odorizers now incorporate an electrically driven dual pump injection system that uses opposing reciprocating pistons to achieve a consistent and accurate odorant injection. The pumps displace hydraulic fluid in a chamber totally isolated from the odorant, allowing for maintenance to be performed without getting "in the stink". The displaced volume causes compression of an infinite cycle welded stainless steel bellow, which displaces an equivalent volume of odorant in the bellows capsule that is continuously injected into the pipeline at any pressure up to 1480 psig. The reciprocation of the pistons is intentionally slow, never exceeding 25 rpm. By keeping piston speeds low (slow), pressure drops in the injector are minimized, and flashing or vaporization of the fluids is prevented.

Optical Sensor Drip Odorizers are used in low-volume to mid-volume applications and is the latest technology on the market. The design is centered upon an optical sensor that counts each drop of odorant to determine very precise volume going into the gas stream. An advantage of this system is that there are no moving parts. An odorant storage vessel is pressurized to a pressure slightly above pipeline pressure using either upstream pressure or a nitrogen source and a pilot regulator. Odorant moves from the tank through a filter to an solenoid/isolation valve. A controller, which is receiving a gas flow signal from a meter, communicates to the solenoid valve when to open allowing odorant to be pushed into the pipeline (due to the higher tank pressure).



New generation (Liquid Injection or Optical Drip) odorizers have system controller interfaces with metering valves / optical system to maintain constant and accurate odorant injection rates proportional to the gas flow rate. The system controllers also enable system monitoring and alarm notifications while documenting performance characteristics that may be requested by state inspectors.



LEAK SURVEY

Natural gas leak survey is the practice of inspecting and assessing the natural gas infrastructure to locate and identify natural gas leaks caused by any number of failures or impingements on the pipeline system. The practice of leak survey is a key component in the ongoing program gas system operators use to determine and track the condition of their pipes. Leaks are often the first indication there may be a problem with buried facilities. The majority of leaks found via leak survey are small and of no immediate hazard to persons or property.

The primary reason to perform leak survey is to locate and eliminate hazardous leaks to ensure public safety. Since most leaks tend to worsen when left untreated, timely discovery and control of leaks is essential to maintaining the safest and most efficient distribution system possible.

Natural gas leak survey was originally performed in a variety of ways, with each individual gas system operator designing their own survey program. One of the earliest forms of gas leak detection included vegetation survey, which involved visually looking for dead or dying vegetation caused by high levels of leaking gas.

Prior to federal and state regulations, the industry routinely followed a voluntary standard called the American National Standard Code for Pressure Piping, Gas Transmission and Distribution Piping System, ANSI B31.8. The first edition of the code was published in 1935 and was limited to specific engineering standards for the safe construction and design of pressure piping, specifically acceptable material, component specifications, and assembly standards. The code was later expanded in 1951 to address gas transmission and distribution piping systems, but was still limited in its leak survey procedures and standards.

The 1937 New London School disaster, caused by an undetected gas leak that ignited and killed nearly 300 students and teachers, still remains the deadliest school disaster in American history. This event spurred the odorization of natural gas, as well as other legislative impacts, but did not cause additional regulation around the practice of leak survey. After the Cleveland East Ohio Gas Explosion (1944), and the Indianapolis Coliseum Explosion (1963), the federal government sought to create federal regulations for natural gas leak survey. In 1968, thirty years after the New London disaster, Congress passed the “Natural Gas Pipeline Safety Act,” which authorized the Secretary of Transportation to create and enforce safety standards for the safe transportation of natural gas by pipeline.

The Office of Pipeline Safety, part of the Federal Department of Transportation, spent the next two years developing safety standards for the industry. In November of 1970, the United States government disrupted the natural gas industry by implementing 49 CFR Part 192 of the Code of Federal Regulations, “Transpiration of Natural and Other Gas by Pipelines: Minimum Safety Standards.” The Gas Piping and Technology Committee (originally backed by the American Society of Mechanical Engineers (ASME)), who supported the ANSI B31.8 Code, worked with the federal government to incorporate the ANSI B31.8 Code standards into the new minimum federal safety standards. That same year the committee compiled the first copy of the Guide for Gas Transmission and Distribution Systems, often referred to as “The Guide,” which incorporated both the federal safety standards and ANSI B31.8 Code which applied to Part 192. “The Guide” served for many years as the authority on safety practices in the pipeline industry.

In 1990, twenty years after “The Guide’s” first publication, the Gas Piping and Technology Committee changed its affiliation with ASME to the American Gas Association (AGA). The Committee along with the assistance of the AGA, went on to apply for and was granted approval for "The Guide's" procedures by ANSI. "The Guide's" 1991-1992 edition became known, as it is still referred to today, as ANSI/GPTC Z380.1. This document is still widely used as the best practices guide for all gas system operators on how to properly perform gas leak survey.

Today, there are regulations at the federal, state, and often municipal level concerning inspections of pipeline facilities. All applicable local and federal laws and regulations must be understood by gas system operators in order for them to develop and deploy effective leak survey programs. Leak surveys performed under these regulations are considered 'compliance surveys' and need to be performed at certain intervals depending on the population density of the area, pipeline materials and pressure, and age of the facility.

Methods of Performing Natural Gas Leak Survey

Most compliance-related gas leak surveys performed today fall into one of two categories. The first involves utilizing a search instrument with an intake cone that drags on the ground above the facilities to detect possible leaking gas rising out of the ground. This method would include walking over every foot of main and service line and inspecting the surface of the gas meter with the device.

The second method utilizes a device that transmits a laser from a remote device in an effort to search for the plume of gas that is created above a gas leak. These remote devices are especially effective when walking above the facilities is impossible or is very unsafe.

Within these two categories, there are a wide range of devices that can be used. Included are flame ionization, internal laser and infrared detection, and a host of other types of sensors. Gas leak indicators are sophisticated instruments that require regular care, maintenance, and calibration, and should be used by trained personnel. The most important feature of any device that is going to be used is the device's sensitivity to detecting minute levels of natural gas.

Manufacturers are also beginning to offer features such as wireless communication and remote monitoring. North America is experiencing a rise in the adoption of new drone technology in the gas detection equipment market for large area surveying. Multi-gas detectors, which can detect multiple types of gas, are gaining market share due to increasing confined space regulations and consumer preference.

Leak Investigation and Grading

When a leak is found, the technician must perform an extensive investigation to determine the grade and severity of the leak. When a leak is detected on above ground piping, a soap solution is sprayed or brushed on and bubbles will form where the leak is occurring. For below ground leaks, a combustible gas indicator (CGI) is used to determine the subsurface perimeter of gas migration. A CGI determines the amount of gas present, and every gas leak survey technician uses a CGI to evaluate/classify leaks found by the initial search instrument.

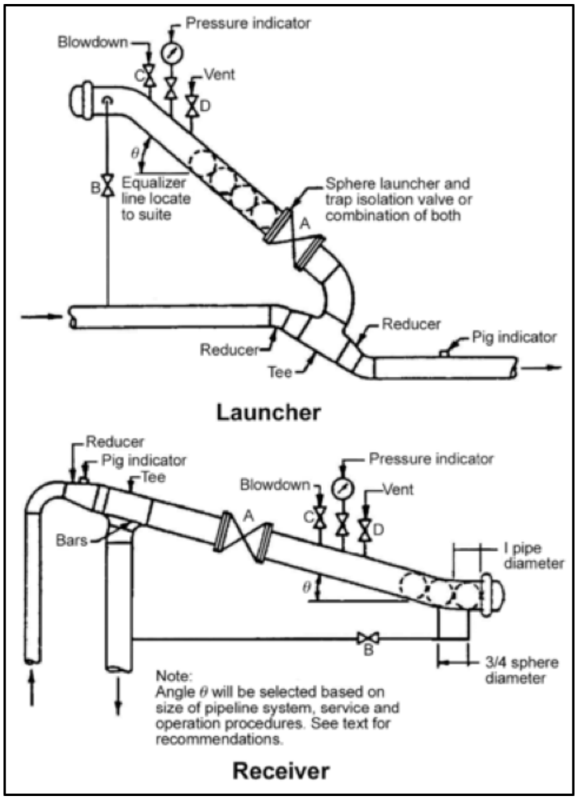
Once the location and concentration of gas is determined, a leak grade (which determines the hazard level and corresponding repair priority for the gas system operator) can be assigned. Each gas system operator maintains an Operations and Maintenance (O&M) Plan based on the federal minimum requirements. By using a standard grading system, a gas system operator protects customers and employees from dangerous leaks. This allows the operator to focus money and resources on eliminating the most dangerous situations first. The repairing of leaks based upon relative hazard (leak grades) is the ultimate purpose of performing survey.

LAUNCHER/RECEIVER FACILITIES

Pigging facilities and considerations should be incorporated into the pipeline system design. Basic pigging facilities require a device to launch the pig into the pipeline and a receiver system to retrieve the pig (Society of Petroleum Engineers).

Pigs are devices that are placed into a pipeline to perform certain functions including cleaning the inside of the pipeline or monitoring its internal and external condition. Launchers and receivers are facilities that enable pigs to be inserted into or removed from the natural gas pipeline.

Pigging facilities are usually smaller than a compressor station but are typically larger than valve stations. They are normally unmanned except during periods of manual pigging and during routing service or repair. The facilities are usually equipped with an office, workshops, a small permanent camp (in remote locations), power generators, and storage areas, etc (UChicago Argonne).



PURGING & PIGGING

Pipeline pigs are devices that are placed inside the pipe and traverse the pipeline. Pigs may be used in hydrostatic testing and pipeline drying, internal cleaning, internal coating, liquid management, batching, and inspection.

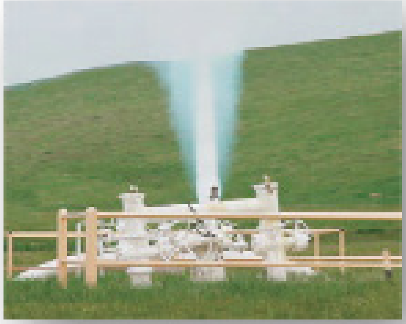
In addition to general cleaning, natural-gas pipelines use pigs to manage liquid accumulation and keep the pipe free of liquids. Water and natural-gas liquids can condense out of the gas stream as it cools and contacts the pipe wall and pocket in low places, which affects flow efficiency and can lead to enhanced corrosion.

Pigs may be used to apply internal pipe coatings, such as epoxy coating materials, in operating pipelines. Pigs may also be used with corrosion inhibitors to distribute and coat the entire internal wetted perimeter. Pigs are being used more frequently as inspection tools. Gauging or sizing pigs are typically run following the completion of new construction or line repair. This determines if there are any internal obstructions, bends, or buckles in the pipe.

Pigs can also be equipped with cameras to allow viewing of the pipe internals. Electronic intelligent, or smart pigs that use magnetic and ultrasonic systems have been developed and refined to locate and measure internal and external corrosion pitting, dents, buckles, and any other anomalies in the pipe wall (Society of Petroleum Engineers).

Purging is the process of displacing one gas by another gas, which occurs on a routine basis in the natural gas industry when pipelines are purged into and out of service.

When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

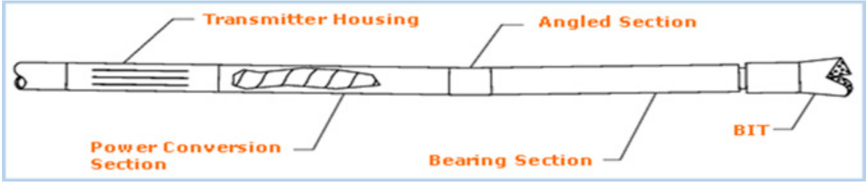


A slug is a quantity of inert gas interposed between combustible gas and air during purging. The slug does not fill the complete length of the pipe, but moves through the pipe as a separate mass to prevent mixing of gas and air (AGA).

HORIZONTAL DIRECTIONAL DRILLING (HDD)

Horizontal Directional Drilling (HDD) or directional boring is a trenchless method of installing underground gas pipelines using surface-launched drilling rig with minimal impact on the surrounding area around pipeline installation. HDD is used when trenching or excavating for natural gas pipeline installation is not practical. The equipment required for HDD is dependent upon pipe diameter, length of the pipe run, and conditions above and below ground.

Installation of a pipeline by HDD is generally accomplished in three stages. The first stage consists of directionally drilling a small diameter pilot hole along a designed directional path. The second stage involves enlarging this pilot hole to a diameter suitable for installation of the pipeline. The third stage consists of pulling the pipeline back into the enlarged hole.



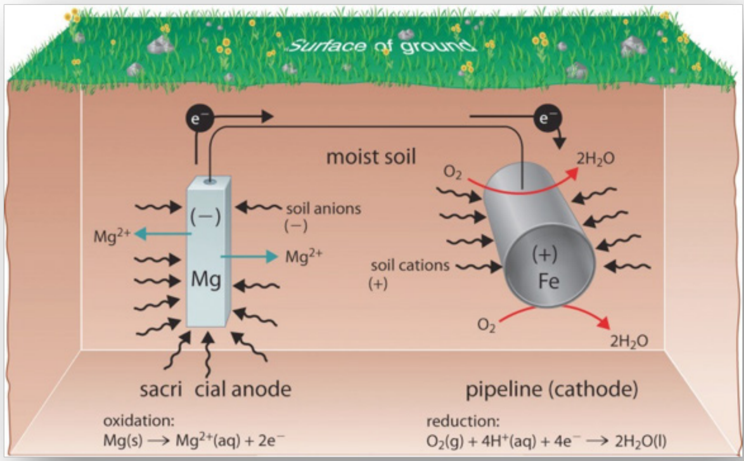
TAPPING & STOPPING

Hot tapping or pressure tapping is the method of making a connection to existing gas piping without the interruption of emptying that section of gas pipe. This means that a section of gas pipeline can continue to be in operation during maintenance or modification operations.

Hot tapping is also the first step in the line stopping process. Line stopping or line plugging is means of isolating a section of gas pipeline to provide a shut-off where none exists. This process provides a control method or temporary valve in the gas pipeline so that pipeline alterations or valve replacements can be performed. After pipeline alterations or valve replacement work is completed, the stop is removed.

CATHODIC PROTECTION

Cathodic Protection (CP) is the process whereby natural gas pipelines are protected from corrosion, primarily on buried pipelines.



CP originated in London in 1824 via a paper presented to the Royal Society by Sir Humphrey Davy. The first application of CP was to the HMS Samarang in 1824. Sacrificial anodes were attached to the copper hull of the ship. This practice was abandoned due to a side effect of accelerated marine growth on the hull of the ship, which affected the performance of the ship. It would be a little over 100 years from the time of Davy's experiment until CP was used in the gas and oil industry. CP was used on steel pipelines as early as 1928.

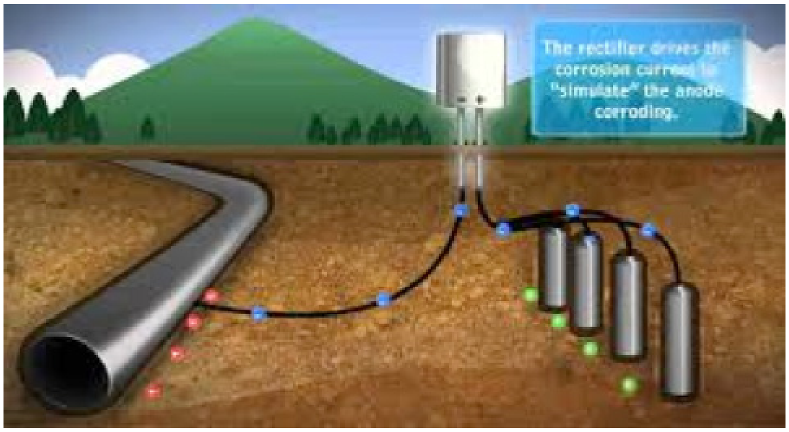
In corrosion, a metal is either anodic or cathodic depending on its location on the anodic scale. The anodic scale lists metals in the order of their anodic or cathodic characteristics. At the top of the anodic scale is gold, which is the least corrosive metal (cathodic), to magnesium which is the most corrosive (anodic). When steel pipe is buried, the soil becomes a path for the corrosion process. If the steel pipe is near another metal which is higher on the anodic scale, then the potential for corrosion exists as the steel will become the anode and the other metal will become the cathode.

To prevent this occurrence, different methods are used by pipeline operators.

Sacrificial anodes: are used for protecting small areas of pipe. They can be made of different materials such as alloys of zinc, magnesium, or aluminum. They are typically buried near the area they are meant to protect and bonded to that area via a welded wire cable.

Impressed current: CP involves the use of a rectifier plus an anode ground bed. The rectifier is a machine designed to impress current to the anode ground bed. The anode bed consists of either horizontal or vertical installed tubes of an anodic material to steel such as graphite, carbon, or magnesium surrounded by coke, which is the residue of the incomplete burning of coal. Sometimes junk iron, such as old railroad rails are used for the anodes.

The rectifier converts AC power to DC power, which is then impressed into the ground bed via the positive side of the DC terminal of the rectifier. The pipeline is connected to the negative side of the DC terminal of the rectifier. As current travels to the ground bed, it is then dispersed into the surrounding soil and travels to the pipeline along various lengths of the pipe. As this process takes place, the anode bed will corrode and the pipeline becomes the protected cathode.



Rectifiers and ground beds will be found at numerous locations along a pipeline as will individual sacrificial anodes.

All pipeline operators have to document the effectiveness of their cathodic protection program. This can be done in several ways. The simplest way is to check for a bare spot on the pipeline with a copper sulfate half-cell.

This half-cell measures the electrical potential between the pipes being tested to the half-cell. A minimum reading of -.85 is required to meet the corrosion protection standard. There are several other more complicated methods to accomplish this, but the half-cell is likely the most common method used.

Components of a Cathodic Protection System Would Include:

- Sacrificial anodes
- Rectifiers
- Anode beds
- Pipe insulators (such as weld end insulators to isolate sections of pipe), or insulated valves on meter / regulator stations.
- Instruments such as the copper, copper-sulfate half-cell.
- Instruments to locate shorts, which are places where the buried pipe may be touching other structures.
- Pipe coatings materials

Who Sells Cathodic Protection Products?

- Southern Cathodic Protection
- Piping & Corrosion Specialties
- Allied Corrosion Co.
- Corrpro Co.
- Corrosion Specialties
- Farwest Corrosion Control Co.
- Champion Corrosion Products Inc.
- Others

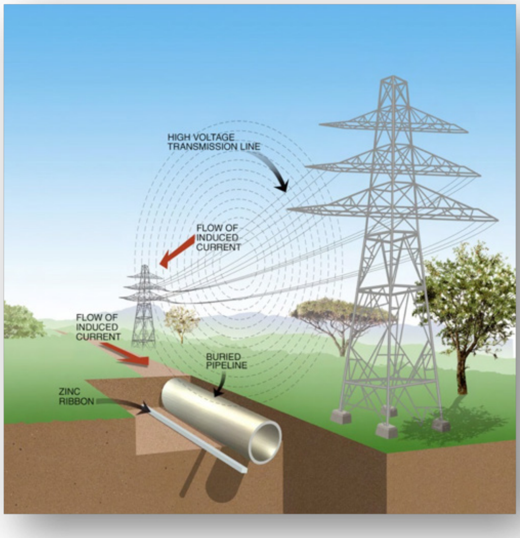
AC MITIGATION

Alternating Current (AC) Mitigation is the process through which natural gas pipelines and personnel are protected from stray current on pipelines and appurtenances. Stray current can come from nearly any source that occupies the same bedding area and has current. More common sources include shared ROW with high voltage electrical/transmission, adjacent pipelines protected by CP sources (ground bed, rectifier, etc.).

AC Mitigation's primary function was initially as a safety measure to remove unsafe levels of current from the pipeline and protect those working on or near the exposed pipeline.

Recent purposes for AC Mitigation also include protection of assets from corrosion. Stray current traveling along a pipeline will naturally follow the path of least resistance. If holidays or imperfections in the coating are present, the current will leave through these holidays resulting in coating damage and potential material loss.
To mitigate stray current, different methods are used by pipeline operators.

1. **Test Stations:** Test stations can be used to measure the voltage on a pipeline.
2. **Zinc Ribbon:** Ribbon connected to underground facilities can serve as a conduit for stray current to leave the pipe in a controlled, non-destructive manner (similar in nature to an anode).
3. **Grounding rods and mats:** Grounding mats are frequently tied into above ground sites (block valves, blow downs, etc.). Deep grounding rods may be used in areas where linear/horizontal access to the pipeline is challenging (roadways or sensitive properties).
4. **Decoupler:** Decoupler can be used to interrupt current from underground material NOT under CP protection. A Solid State Decoupler (SSD) is a common decoupler used at stations to protect equipment tied to grounding systems.



CP and AC mitigation should always be a coordinated extension of a comprehensive integrity management plan to avoid interference and functional conflict.

SECTION THREE

APPENDICES

APPENDIX A. FUTURE TOPICS

- System Integrity & Regulatory Compliance
- SCADA-Gas Control-Actuation
- Maintenance & Repair Equipment
- Control & Relief Valves
- Gauges
- Others

APPENDIX B. COMMON GAS UTILITY EXAMPLE/SAMPLE OF PROCESS AND REQUIREMENTS FOR GAS SERVICE

Common Gas Utility Example/Sample of Process and Requirements for Gas Service (For Reference Only)

1. Gas services should be installed along the shortest practical, available and accessible route that is not subject to undue stresses, hazardous conditions or obstructions. Obstructions may require removal at customer expense.
2. Gas Services should not be installed where erosion, pooling of water, blasting operations, excessive soil subsidence or tunneling operations occur.
3. A gas service should be installed parallel to the lot line and at 90˚ to the main. If a lot line is not perpendicular to the main, a bend at the property line is allowed to keep the lot line and service parallel. If a bend is not practical, the entire service may be run parallel to the lot line (see Illustrations on the following page).
4. When offsets are necessary, they should be made at right angles.
5. When making a stub extension, any necessary offsets should be made inside the property line unless a lot line would be crossed, then the offset would be made on the street side of the property line.
6. A new gas service cannot cross a 3rd party's property or connect to the gas service of the 3rd party without Utility approval. A written acceptance agreement and easement must also be obtained from the 3rd party.
7. Gas services will not be connected within 10' of the end of a main if the main could be extended in the future. If not extendable, within 5' is permissible.
8. The Customer may be required to dig a service trench if the slope along the service route is greater than 33% of grade (3 horizontal to 1 vertical ratio).
9. Gas Services WILL NOT be installed under or through concrete slabs, buildings, roofed passageways or enclosed or limiting structures.
10. Service pipe or stubs for residential lots may be installed in dirt or within a 3" to 4" schedule 40 pvc pipe sleeve or conduit.
11. Service pipe or stubs do not require encasement within a conduit or pipe sleeve when crossing beneath streets or sidewalks.
12. Pipe sleeves or conduits may be used for installing up to 2 stubs or services.
13. A pipe sleeve or conduit must extend beyond the pavement, concrete or curb.
14. Gas services should not extend more than 5' beyond the building wall nearest the gas main. If the distance is greater, the service line should be installed parallel to the building but at least 5 feet from the wall.
15. A Gas Service riser MUST be located ≥ 12 inches from the final building wall.
16. Installing a riser requires a 3' x 5' clear area (exposed dirt). The 5' dimension must be in line with the route of the service pipe.
17. A concrete apron or sidewalk poured after a riser is installed requires a schedule 40 PVC collar around the riser that is 2" or larger than the riser OD.

APPENDIX C. REFERENCES

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