Kirk-Othmer Encyclopedia of Chemical Technology.

PIPELINES

Pipelines or pipe lines are continuous large-diameter piping systems, usually buried underground where feasible, through which gases, liquids, or solids suspended in fluids are transported over considerable distances. They are used to move water, wastes, minerals, chemicals, and industrial gases, but primarily crude oil, petroleum products, and natural gas. In the oil and gas business, a pipeline system consists of a trunkline, ie, the large-diameter, high pressure, long-distance portion of the piping system through which crude oil is shipped to refineries, or natural gas and oil products, respectively, are transported to distribution points, and smaller low pressure gathering lines that transport oil or gas from wells to the trunkline. Smaller lines used by natural gas distributors are not considered part of a gas pipeline system (see Gas, natural).

Pipeline transport involves the application of force to the material being moved, either through the use of pumps to transport liquids, compressors to move gases, or flowing water to move solids. In some applications, vacuum may create the pressure differential.

1. Pipeline Transport of Gases

Essentially all substances that are gases at standard conditions of temperature and pressure are transported commercially by pipeline, this includes ammonia, carbon dioxide, carbon monoxide, chlorine, ethane, ethylene, helium, hydrogen, methane (natural gas), nitrogen, oxygen, and others. Gases with moderate boiling points can be pipelined in either gaseous or liquid form; liquefied petroleum gases (LPG), carbon dioxide, ammonia, and chlorine are usually shipped as liquids because of the smaller pipeline volume for liquids.

The largest pipeline transport of gas, by far, is the movement of methane (natural gas). Natural gas can be liquefied, but it is not pipelined in liquid form because of cost and safety considerations. For overseas transport, it is shipped as liquefied natural gas (LNG) in insulated tankers, unloaded at special unloading facilities, vaporized, and then transported over land in pipelines as a gas.

1.1. Gas Pipeline Industry

In early gas industry days, the U.S. Congress mandated that any pipeline must have an ensured 20-year supply of gas before it could receive a permit to operate. The pipeline companies signed long-term purchase contracts with producers to satisfy this mandate and transported the gas to the cities where it was sold and title taken by the gas distribution companies. In the mid-1980s, however, the Federal Energy Regulatory Commission (FERC) began a restructuring of the industry that was to remove the merchant role from the gas pipelines and ultimately establish them as common carriers, comparable to railroads and liquid pipelines. Distribution companies and large gas users, such as corporations, may buy their own gas directly from producers, aggregators, or marketers and contract with pipelines to transport it for a fee.

This industry restructuring, coupled with removal of price controls and a large deliverability–demand inbalance, the so-called gas bubble, led to low gas prices during the late 1980s and early 1990s and resulted in the formation of a spot market for natural gas, a gas futures market, and a need for more sophisticated gas technology. The common carrier status of natural gas pipelines allows many small producers to enter the pipelines, if pipeline capacity is available, and make deliveries on a short-term (spot) basis. Flow computers at entry and exit points along the pipeline provide an instantaneous and accurate account of the gas that enters or leaves the pipeline. The flow computers tie into a large computer at pipeline headquarters to record an accurate account of gas from producers entering the pipeline as well as gas exiting to a gas user or distributor. In addition, FERC Order 636 mandated the establishment of an electronic bulletin board (EBB) for the gas industry, by which anyone with a personal computer can obtain the latest information needed to purchase gas and transport it by pipeline, such as suppliers' prices, available pipeline capacity, etc (1). The EBB will also carry information about capacity release in pipeline operations and permit trading of capacity release options so that elements of pipeline capacity will become a commodity, just as the natural gas itself. The objective is to optimize the efficiency of the national gas pipeline grid (2).

1.2. Methane (Natural Gas)

Although the first natural gas pipeline was constructed in 1870, most of the gas consumed at that time was manufactured from coal (qv) and used locally rather than transported by long-distance pipeline. In the 1990s, natural gas is conveyed in strong, thin-walled, long-distance pipelines in virtually all principal countries of the world. In the United States, the total length of gas pipelines is ca 5.82×10^5 km, which includes ca 4.24×10^5 km of transmission pipelines, ca 1.49×10^5 km of field (gathering) lines, and ca 0.09×10^5 km of lines in storage areas (3, 4). This represents ca 73% transmission pipelines, 25.5% gathering lines, and ca 1.5% storage lines. Collectively, long-distance gas pipelines account for only about one-third the natural gas transport system in the United States; the other two-thirds are gas distribution mains to consumers.

Polyethylene (PE), poly(vinyl chloride) (PVC), or polypropylene plastic pipe is being used in increasingly greater amounts throughout the world in both gas gathering systems and gas distribution systems. U.S. gas distribution companies have installed 644,000 km of polyethylene piping since its introduction in 1968 and are adding over 40,000 km each year (5). Plastic pipe is used in sizes greater than 400-mm dia for certain nonpressurized nongas applications, but is not used in sizes of greater than 400-mm dia for natural gas and not at all for truly long-distance natural gas pipelines. When plastic pipe is installed under roads, casings are often required. Railroads do not allow polyethylene pipe to be used at crossings; the additional installation costs for crossings can reduce the economic advantages of using plastic pipe for long pipelines (6).

Transport of natural gas starts with small-diameter gathering lines that convey the raw gas from individual wells to a collection point and from there to a gas treating plant, where heavier hydrocarbons (qv), particulates, and water are separated from the gas. The hydrocarbons known as natural gas liquids (NGL) are transported as raw mix in liquid pipelines to chemical plants, where they are fractionated into lighter and heavier fractions that are transported to market areas in products pipelines. The methane-rich gas, which usually contains some ethane, is processed to remove particulates, water, and gaseous impurities such as hydrogen sulfide, carbon dioxide, etc, and then compressed to the appropriate pressure for transmission by large-diameter pipeline. Pressure is maintained by large compressors at compressor stations along the length of the pipeline, usually spaced 80–160 km apart (7). Maximum operating pressures are 3.45 MPa (500 psi) for older lines and 9.93 MPa (1440 psi) for newer lines.

Of the 125 U.S. gas pipelines listed in 1991, 47 were rated as principal pipelines, ie, 1.42×10^9 m^3 of gas transported or stored for three consecutive years (4). The longest gas pipelines originate near the largest U.S. gas producing areas, primarily the Gulf of Mexico and the mid-continent area of Oklahoma, Texas, Kansas, New Mexico, etc, and move gas to the more populated areas of the country, ie, Los Angeles, Chicago, New York, or New Jersey. Maps showing the locations of natural gas pipelines in the United States (8) and Europe (9) are available.

Some U.S. natural gas pipeline companies are subsidiaries of gas holding companies. The largest U.S. natural gas pipeline companies, in terms of overall length of transmission systems are Northern Natural Gas Company, 26,539 km; Tennessee Gas Pipeline Corporation, 23,567 km; Columbia Gas Transmission Company, 18,481 km; Natural Gas Pipeline Company of America, 17,200 km; and Transcontinental Gas Pipe Line Corporation, 17,071 km. For gas moved in 1994, the four largest pipelines were ANR Pipeline Company, $95,278 \times 10^6$ m^3 (3,363,275 MMcf), of which 40.8% was gas moved for others; Transcontinental Gas Pipe Line Corporation, $87,050 \times 10^6$ m^3 (3,073,801 MMcf), of which 99.7% was moved for others; Natural Gas Pipeline Company of America, $83,089 \times 10^6$ m^3 (2,933,940 MMcf), of which 87.1% was moved for others; and Northern Natural Gas Company, $56,523 \times 10^6$ m^3 (1,995,861 MMcf), with 100% moved for others.

In Europe, Russia's huge natural gas resources are being moved to Western Europe by pipelines from Siberia to the consuming countries. Gas from Algeria's large resources is moved by 2500-km, 1200-mm dia pipeline from the Hassi R'Mel gas field across the Mediterranean Sea and the Strait of Messina to Italy in water depths reaching to 610 m. A 1448-km pipeline will carry Algerian gas to Spain and Portugal via Morocco. Norway's Statoil will build a 1095-km pipeline system (Zeepipe) from the North Sea to Europe. In South America, a 2252-km gas pipeline will transport natural gas from producing fields in Bolivia to Sao Paulo, Brazil, and hook up with a line between Sao Paulo and Rio de Janiero. A gas pipeline that would cover 27,000 km has been proposed by the National Pipeline Research Society of Japan to transport gas from Siberia and Sakhalin Island to Australia by way of Japan, China, Thailand, Malaysia, and Indonesia (9).

1.2.1. Ammonia Pipelines

Ammonia [7664-41-7] is a commodity produced from natural gas and may be produced in plants located near its market areas or plants may be located near gas-producing regions and the ammonia transported to the market areas by tank car, barge, or pipeline. The primary ammonia pipelines in the United States are the Mid-America Pipeline Company (MAPCO) and Gulf Central, both connecting ammonia-producing areas in Texas, Oklahoma, and/or the Gulf Coast with farming districts throughout the Midwest. The pipelines are made of high strength pipeline steel, 200–250-mm dia, and operate with an ammonia pressure of 2.07–10 MPa (300–1450 psi) to maintain the ammonia in the liquid state. A limit of 0.2% H_2O and 0% CO_2 in the ammonia is specified to minimize stress–corrosion problems. Stress–corrosion cracking of the high strength pipeline steel can occur if the ammonia is contaminated by atmospheric carbon dioxide. Copper-base alloys are corroded by ammonia in the presence of air and water, and equipment containing these metals can be corroded by even small ammonia leaks. The MAPCO ammonia pipeline has resolved these problems by using a special steel containing 0.25% C, 1.0–1.7% Mn, and 0.15% Cu; eliminating copper alloys from valves, fittings, and pumps; stress-relieving fabricated valves or using cast valves and stress-relieving pipe fabrications containing branch connections; and using neoprene for valve trim (10).

A Russian ammonia pipeline of nearly 2400 km extends from Togliatti on the Volga River to the Port of Odessa on the Black Sea, and a 2200-km, 250-mm dia branch line extends from Gorlovka in the Ukraine to Panioutino. The pipeline is constructed of electric-resistance welded steel pipe with 7.9-mm thick walls but uses seamless pipe with 12.7-mm thick walls for river crossings. The pipeline is primed and taped with two layers of polyethylene tape and supplied with a cathodic protection system for the entire pipeline. Mainline operating pressure is 8.15 MPa (1182 psi) and branch-line operating pressure is 9.7 MPa (1406 psi) (11).

1.2.2. Hydrogen Pipelines

The manufactured gas distributed by early gas distribution systems contained up to 50% hydrogen, and at least two large-scale operations in the 1990s have evaluated 10–20% hydrogen mixtures with natural gas, but actual experience with long-distance hydrogen pipelines is rather limited. The oldest hydrogen pipeline (started in 1938) is the Chemische Werke Hüls AG 220-km, 150–300-mm dia system in the German Ruhr Valley that transports 100×10^6 m^3 of hydrogen annually to multiple users at a nominal pressure of 1.55 MPa (225 psi).

Following its expansion after 1954, some fires have occurred but no hydrogen embrittlement or explosions (12, 13). Other shorter H_2 pipelines include a 340-km network in France and Belgium, an 80-km pipeline in South Africa, and two short pipelines in Texas that supply hydrogen to industrial users (14). NASA has piped H_2 through short pipelines at their space centers for several years.

Natural gas is roughly eight times more dense than hydrogen (0.72 g/L vs 0.09 g/L). Because the pipeline capacity of a pipeline depends on the square root of the gas density, the pipeline capacity of hydrogen is nearly three times greater than for natural gas. The heating value of hydrogen, however, is only about one-third of the 37.2 MJ/m^3 heating value for an equivalent volume of natural gas. Thus, the energy carrying capacity of a given size pipeline is approximately the same when it is carrying either hydrogen or natural gas, provided that it is operating in turbulent flow with the same pressure drop along its length and at the same operating pressure. At higher pressures, the ratio of heating values of natural gas and hydrogen increases and at 5.17 MPa (750 psi); the ratio is 3.8:1, compared with about 3:1 at atmospheric pressure. This also means that hydrogen compressors must handle 3.8 times more gas than natural gas compressors for the same energy throughput, thus indicating higher pipeline transmission costs for hydrogen than for natural gas. One study suggests that regional transport costs for hydrogen may be as much as five times greater than for natural gas at the higher pressures but that long-distance pipeline transport should not show such a large difference (15). Some components currently used for natural gas may be adequate for hydrogen service but not compressors and meters. In view of the different compressor requirements for hydrogen and natural gas, the design of rotary compressors used for natural gas is probably not satisfactory for hydrogen use (12, 16).

The question of whether hydrogen embrittlement of pipeline steel is a problem has not been completely resolved. No hydrogen embrittlement problems were reported for hydrogen pipeline transmission at 5.17 MPa (750 psi), and an American Petroleum Institute (API) study of steels operating in hydrogen service indicates no problems at temperatures below 204°C and pressures of 69 MPa (10,000 psi). Other tests of pipeline steels at hydrogen pressures of 3.5–6.9 MPa (500–1000 psi) have shown a loss of tensile ductility and accelerated fatigue-crack growth. Embrittlement is a potential problem in high pressure pipeline transmission of hydrogen (13).

1.3. Industrial Gases

Industrial gas (oxygen, nitrogen, etc) pipelines are short compared with long-distance pipelines that transport crude oil, natural gas, or petroleum products; however, more than 80% of the oxygen and more than 60% of the nitrogen produced in the United States by air separation is transported by pipeline. Air-separation plants that are built adjacent to the oxygen or nitrogen users' facilities are usually owned and operated by the user or a second party. However, plants located at more distant locations are usually owned and operated by the oxygen producer and the gases transported by pipeline to multiple users in the area, eg, the 150-km, 406-mm dia Houston Ship Channel pipeline system that supplies oxygen and nitrogen from air-separation plants to chemical plants and oil refineries from Houston to Texas City, Texas (17). Carbon dioxide and hydrogen are also moved by pipeline in the Houston area. Other U.S. industrial gas pipeline systems are located near Gary, Indiana, and along the Mississippi River near the Gulf Coast (18). Multiple users of oxygen (qv), nitrogen (qv), hydrogen (qv), and carbon monoxide (qv) near Rotterdam, the Netherlands, are supplied by pipeline from a nearby industrial gas complex. Oxygen has been transported for many years by a French pipeline connecting Metz with Nancy and extending to Luxembourg and Saarbrucken in Germany.

The application that has led to increased interest in carbon dioxide pipeline transport is enhanced oil recovery (see Petroleum). Carbon dioxide flooding is used to liberate oil remaining in nearly depleted petroleum formations and transfer it to the gathering system. An early carbon dioxide pipeline carried by-product CO_2 96 km from a chemical plant in Louisiana to a field in Arkansas, and two other pipelines have shipped CO_2 from Colorado to western Texas since the 1980s. Feasibility depends on crude oil prices.

Helium is extracted from natural gas in the southwestern United States and moved by a 685-km, 50-mm dia pipeline to storage in a partially depleted gas field near Amarillo, Texas, as part of the U.S. government's helium conservation program.

1.4. Cryogenic Gases

Some of the most sophisticated pipeline technology deals with the transport of liquefied gases with very low boiling points, ie, cryogenic gases such as oxygen ($-182.96°C$), argon ($-185.7°C$), nitrogen ($-195.8°C$), hydrogen ($-252.8°C$), and helium ($-268.9°C$). These gases are liquefied by modern cryogenic methods and shipped in cylinders or special storage vessels for bulk liquid transport and storage (see Cryogenics). However, development of a system for piping them as liquids has been brought about by the needs of the space program, superconducting magnets, and other high technology areas. The use of liquid hydrogen as a rocket fuel and liquid oxygen as the oxidant has resulted in piping these cryogenic materials to launching and test sites; the use of liquid helium to cool superconducting magnets led to the development of vacuum-jacketed, liquid nitrogen-shielded piping systems (qv). Most of the lines have been relatively small-diameter systems; however, similar but unshielded vacuum-jacketed lines up to 356-mm dia (19) and 8184 kPa (1200 psi), which would qualify as pipeline-sized piping, can be manufactured. CVI, Inc. (Columbus, Ohio) produces pipe for liquid helium consisting of an inner line of stainless steel that is wrapped with aluminized Mylar and glass fiber paper and may be shielded by a patented aluminum extrusion cooled with liquid nitrogen or cold helium gas; the extrusion shield is also wrapped with superinsulating paper. This assembly is completely enclosed, tested, and factory sealed in a vacuum jacket with a stainless steel outer pipe, as shown in Figure 1 (20). Piping systems based on similar technology are also designed for transfer of liquid oxygen, liquid nitrogen, and liquid hydrogen; liquefied natural gas has also been transferred in vacuum-jacketed piping. Thus far, transfer lines are short by comparison with the longer-range pipelines for other applications, but many thousands of vacuum-jacketed piping installations in the 30–150-m range have been installed, with one system over 8 km in length.

2. Pipeline Transport of Liquids

The main technical difference between liquid and gas pipeline transport is the compressibility of the fluid being moved and the use of pumps, rather than compressors, to supply the pressure needed for transport. The primary use for liquids pipelines is the transport of crude oil and petroleum products.

2.1. Crude Oil and Products Pipelines

The true pioneering in long-range modern oil pipelines was the construction of two pipelines to move crude oil from Texas to New Jersey and Pennsylvania during World War II. These were named the Big Inch (2156-km, 600-mm dia) and the Little Big Inch (2373-km, 500-mm dia) pipelines.

The crude oil delivery system starts with relatively small-diameter gathering lines from individual producing wells to a main-line pump station, from where it is pumped through a larger transmission trunkline to a refinery or other destination. At the refinery, the crude oil is separated into gasoline, jet fuel, kerosene, distillate fuel oil, etc, and the refined products are transported by products pipelines to markets, storage, shipping terminals, etc. In modern lines, all inputs and outputs are metered, monitored, and remotely controlled by supervisory control and data acquisition (SCADA) computer systems.

Several different refined products are shipped in the same pipeline (batching) by using control methods to minimize intermingling at different interfaces. This is achieved by maintaining high turbulent flow in the pipe. Synthetic rubber spheres have been used as separators at interfaces but are not used often in the 1990s. Intermingling occurs at the interfaces, but it can be estimated and minimized. At the terminal, the comingled

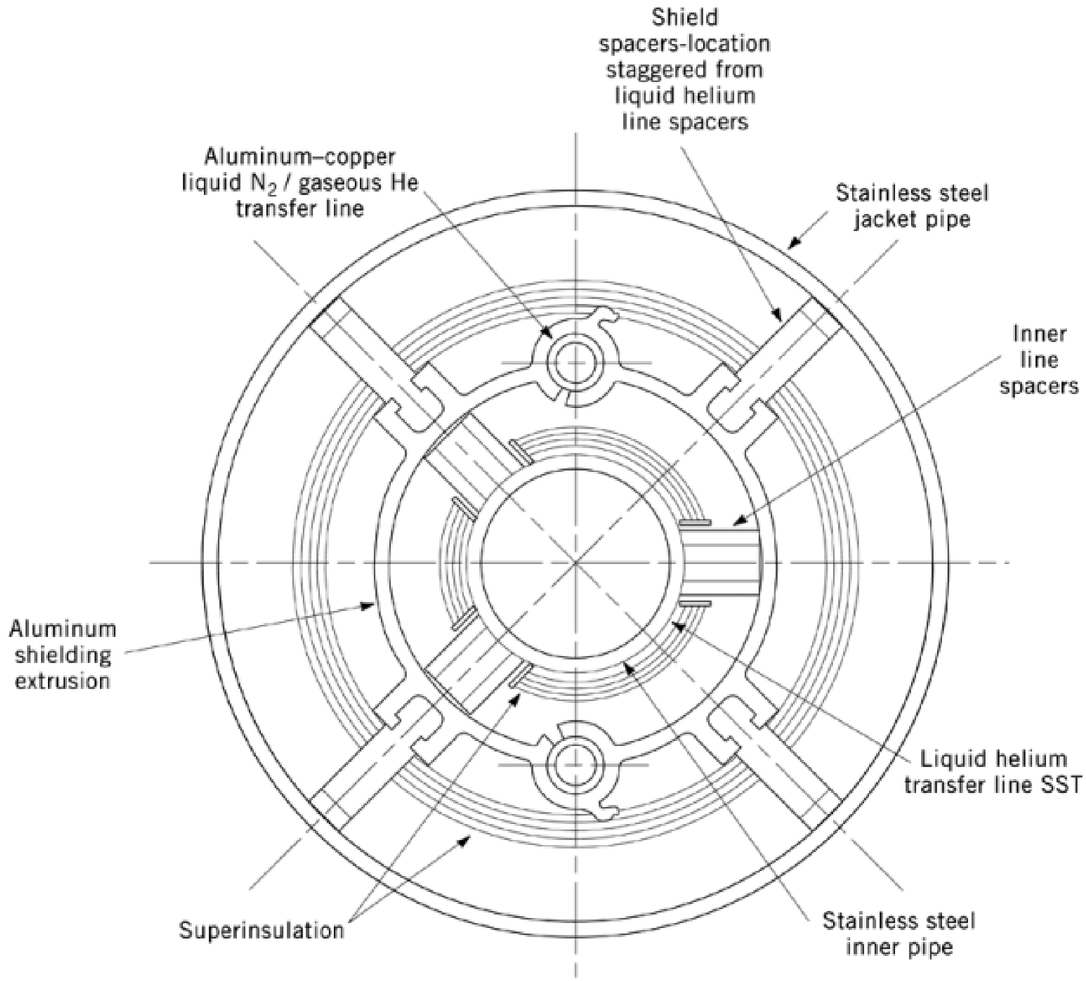

Fig. 1. Vacuum-insulated helium piping.

fraction is separated from other products and either blended or returned to the refinery. Interfaces between products are delineated with densitometers. This technique is used to ship different types of crude oil in the same pipeline.

The liquids pipeline subsidiaries of principal oil companies with both production and refining facilities generally operate all three types of liquids pipelines: gathering, transmission, and products lines. However, the independent 9000-km, 900-mm dia Colonial Pipeline transports only products. It carries about 105×10^6 m^3 of products annually. Of the nearly 276,000 km of liquids pipelines reported in 1991 by FERC, 47% were products lines, 34% were transmission lines, and only 19% gathering lines. This compares with 35, 34, and 31%, respectively, in the 1970s. The total length of the U.S. operating interstate pipeline system has remained relatively constant since 1982 at about 720,000 km, with roughly 32% represented by liquids pipelines and 62% by natural gas pipelines (4).

At the beginning of 1992, the largest liquids pipelines in the United States, based on pipeline length, were Amoco Pipeline Co., 19,096 km; Mobil Pipe Line Co., 15,026 km; Exxon Pipeline Co., 14,983 km; and Conoco Pipe Line Co., 12,980 km. Distances do not include 1316 km of the Trans-Alaska Pipeline with multiple ownership. In both 1991 and 1992, the product pipeline company with the most product deliveries was Colonial Pipeline with 104,990,000 m^3, more than double the amount delivered by Santa Fe Pacific Pipelines, Inc. The top pipeline in terms of crude oil deliveries was the Alyeska Pipeline Service Co., operator of the Trans-Alaska Pipeline System, with movement of 105,735,000 m^3 (3).

2.2. Sulfur and Chlorine Pipelines

Underground sulfur is melted by superheated water and then piped as liquid to the surface with compressed air. At the surface, molten sulfur is transported by heated pipeline to a storage or shipping terminal. One such pipeline, located under 15 m of water in the Gulf of Mexico, is insulated and surrounded by steel casing to which are strapped two 130-mm dia pipelines that carry return water from the deposit. The superheated water is carried from shore to the deposit in a 63.5-mm dia pipe inside the pipeline that carries the molten sulfur (21).

Chlorine is shipped by pipeline in either gaseous or liquid form; however, great care must be taken to ensure that liquid pipelines are operated only in the liquid phase and gaseous pipelines operated only in the gaseous phase. Liquid chlorine has a high coefficient of thermal expansion and high pressure develops with increasing temperature; liquid chlorine trapped between two valves can lead to hydrostatic rupture of the pipeline. Because chlorine is corrosive and has a high vapor pressure, it and the pipeline must be dry before the chlorine enters the pipeline. Operating pressure should not exceed 217 MPa (31,465 psi) and temperature should be no higher than 121°C (22).

2.3. Trans-Alaska Pipeline

The design and construction of the Trans-Alaska Pipeline was one of the most difficult and ambitious pipeline projects ever attempted. Its 1316-km length extends from the producing fields at Prudhoe Bay across three mountain ranges, where up to 12 m of winter snow and wind chills of −73°C can be expected, to the Valdez Marine Terminal on the southern coast of Alaska. Thirteen bridges were built to carry the pipeline across rivers and difficult terrain. To avoid localized melting of the permafrost by the 32–49°C crude oil and possible instability of the soil, a significant portion of the pipeline was installed above ground, supported by 78,000 vertical support members embedded in permafrost to depths ranging from 4.5 to 18 m. The pipeline is insulated and jacketed to reduce heat losses, and passive refrigeration is used to keep the soil frozen around the vertical support members which can move up or down, thus allowing a 0.6-m vertical movement of the pipeline. The pipeline is laid out in a zigzag fashion to allow a 3.6-m horizontal movement for pipe expansion and contraction and possible seismic disturbances. The buried portion of the pipeline is 611-km long, with 6.4 km of it refrigerated. The aboveground portion of the pipe is at least 1.5 m above the surface to permit caribou migration underneath and at least 3 m above the surface at the 554 special animal crossings. The pipeline is constructed of 1219-mm dia high tensile strength carbon steel, with wall thickness of either 11.7 or 14.3 mm. Although the Prudhoe Bay oil discovery was announced in 1968, the initial pipe of the pipeline was not laid until early 1975 because of many delays. Final weld was made May 31, 1977 (23, 24). Final cost, including construction interest, was roughly $11 billion.

3. Pipeline Transport of Solids

Pipelines to transport solids are called freight pipelines, of which three different types exist: pneumatic pipelines, the use of which is known as pneumotransport or pneumatic conveying; slurry pipelines, which may also be called hydrotransport or hydraulic conveying; and capsule pipelines. When air or inert gas is used to move the solids in the pipeline, the system is called a pneumatic pipeline and often involves a wheeled vehicle inside the pipeline, propelled by air moving through the pipe (25). Slurry pipelines involve the transport of solid particles suspended in water or another inert liquid. Hydraulic capsule pipelines transport solid material within cylindrical containers, using water flow through the pipeline for propulsion.

3.1. Pneumatic Pipelines

Pneumatic pipe systems are used to move blood samples, medicine, and supplies between buildings in hospital complexes; cash and receipts in drive-up banks; parts and materials in factories; refuse from apartment complexes; and grain, cement, and many other materials. Most of these are small diameter and usually short; however, a 17-km, 1220-mm dia pneumatic pipeline has been used to transport rock in the former Soviet Union since 1981, and a 3.2-km, 1000-mm dia line has moved limestone from the mine to a cement plant in Japan since 1983 (22).

3.2. Slurry Pipelines

Finely divided solids can be transported in pipelines as slurries, using water or another stable liquid as the suspending medium. Flow characteristics of slurries in pipelines depend on the state of subdivision of the solids and their distribution within the fluid system. Although slurry flow and conventional liquid flow are both divided into laminar, transitional, and turbulent flow, the contribution of the solids-to-slurry flow results in a further characterization as either homogeneous or heterogeneous flow. Homogeneous flow of slurries occurs when very finely divided solids are distributed uniformly throughout the suspending medium, eg, bentonite slurries as drilling muds. These slurries are usually quite concentrated and often have viscosities much higher than those of the suspending medium itself. Heterogeneous flow occurs when larger, irregular solid particles are slurried and distribution is not uniform throughout the suspension; these slurries are usually of lower solids concentration and viscosities are comparable to that of the suspending liquid.

The difference between homogeneous and heterogeneous flow is due to the deposition velocity, below which solid particles start to separate from the slurry and build up in the pipeline, and is related to the degree of turbulence and the particle fall rate. Homogeneous slurries behave more like single-fluid systems; deposition velocity is primarily a property of heterogeneous slurries. Deposition velocity increases with increasing particle density, solids concentration, particle size, and pipeline diameter. In the transport of heterogeneous slurries, turbulent flow is an important requirement to prevent solids from building up in the pipeline. Slurries may be classified according to particle size, eg, colloidal ($<1\ \mu$m), structured (1–50 μm), and finely dispersed (50–150 μm, mostly produced by grinding). A polydispersed structured category, often encountered with products of technological processes and produced by dispersion and grinding, is also defined and described as containing a broader ranger of particles, eg, from finer particles to coarser particles, and sometimes lumps (26). A maximum flow velocity to minimize pipe wall erosion must be determined.

Slurry pipeline design is similar to the design of conventional liquid pipelines, except for the slurry preparation stage and, if necessary, an additional step for separating the suspended solids from the suspending liquid at the point of use. In some instances, such as the direct firing of a concentrated homogeneous coal slurry, this final separation step is unnecessary. In the United States, the Coal and Slurry Technology Association has focused its attention on the development of coal–water–fuel (CWF) and its eventual commercialization, rather than on transportation by slurry pipelines (27).

3.2.1. Coal Slurry Pipelines

The only operating U.S. coal slurry pipeline is the 439-km Black Mesa Pipeline that has provided the 1500-MW Mohave power plant of Southern California Edison with coal from the Kayenta Mine in northern Arizona since 1970. It is a 457-mm dia system that annually delivers $\sim 4.5 \times 10^6$ t of coal, the plant's only fuel source, as a

Table 1. Mineral Slurry Pipelines

Pipeline	Location	Slurry	Length, dia (km,mm)	10^6 t/yr
M. & Chem. Philip	Georgia (U.S.)	kaolin	25.6,200	
Trinidad Cement	Australia	clay, limestone	9,200	
Calaveras	California (U.S.)	limestone	27,150	1.36
VALEP	Brazil	61% phosphate	120,250	2
SAMARCO	Brazil	66% iron ore	400,500	6.35
Da Hong Shan	China	iron ore		
Pena Colorado	Mexico	iron ore	48,200	1.8
Savage River	Tasmania	iron ore	85,250	2.3
Waipipi	New Zealand	iron sands	9.3[a]	
	Bougainville	copper ore	27,152	
	Bougainville	copper ore	105,102	
Hondo	Japan	ore wastes	71[a]	
	South Africa	uranium sands	19,150	

[a]Length.

48.5–50% slurry. Remote control of slurry and pipeline operations is achieved with a SCADA computer system. In 1992 coal delivery cost from mine to power plant was calculated to be \$0.010/t·km (\$0.015/t·mi) (28).

Several coal slurry pipelines were planned for the United States during the 1980s, primarily to deliver low sulfur coal from mines in Montana and Wyoming to power plants in Texas and other states in the southern United States. None was built, however, because of vigorous opposition from water conservationists, who opposed using scarce water resources for the slurrying medium, and the railroads, who feared competition for the utility coal markets (29, 30). In addition, lower prices for oil and natural gas provided little incentive to develop lower cost competitive fuels; however, a study for the U.S. Department of Energy (Pittsburgh Energy Technology Center (PETC)) indicated that coal–water fuels (CWF) could be produced for less than \$1.91/m^3 of oil equivalent (31), and it is expected that there will be renewed plans for coal slurry pipelines (32).

The former Soviet Union constructed a 262-km, 508-mm dia experimental coal slurry line between the Belovo open-pit coal mine in Siberia's Kuznets basin to an electric power plant at Novosibirsk, using technology developed by Snamprogetti. Testing began in late 1989 and tentative plans call for construction of two much larger slurry pipelines, each 3000-km long, with capacity to move a total of 33×10^6 t/yr to industrialized areas near the Ural Mountains (27, 33).

3.2.2. Mineral Slurry Pipelines

Bentonite clay slurries, used as drilling muds in oilwells, are probably the most universally used mineral slurries. Although they are not transported by pipelines over great distances, they represent a significant contribution to slurry pipeline technology because they led to the development of powerful pumps needed to force oilwell drilling muds downhole to the rotating bit, where the mud cools the bit and also carries rock chips from the hole back to the surface. The pumps developed for this application contributed greatly to the development of the huge positive-displacement reciprocating pumps used for pumping slurries through pipelines (29). Table 1 gives some examples.

3.2.3. Fiber Slurry Pipelines

Pipelines to carry suspensions of wood, paper, sludge, etc, have found commercial acceptance. Most of them are less than 15 km long but have diameters of up to 500 mm. These slurries are often concentrated and display viscous plastic properties, although particle sizes may vary; special pumps are used. One such hydrotransport system carries a cellulose slurry by pipeline from the plant to a paper plant near Heidenau, Germany. The

250-mm dia pipeline carries 60 t/d over the 3-km distance to thickeners. In Sweden, a 3.7-km, 500-mm dia pipeline moves cellulose by pressurized hydrotransport from a cellulose plant in Wifstaur to a sulfite plant at Fagervik (26). The former Soviet Union has also been active in pipeline transport of fiber slurries in the cellulose (qv) and paper (qv) industries and the movement of municipal waste from aeration plants. For example, municipal sewage sludge from the Kozhukhovskaya purification plant has been transported by a 2-km, 300-mm dia pipeline to settling areas since 1936, and a 70-km, 400-mm dia pipeline has moved sludge from the Lyublino aeration plant in Moscow since 1954 with no plugging (26).

3.3. Capsule Pipelines

Capsule pipelines involve the transport of material inside a closed cylindrical container propelled by water flowing through the pipeline. This is called hydrotransport and the diameter of the cylindrical container is approximately 90–95% the diameter of the pipeline. Water is 1000 times more dense than air under standard conditions, so the buoyancy is much greater than in pneumatic pipelines and permits capsules to be suspended at relatively low water flow velocities. First proposed during World War II, the concept was resurrected in the 1960s and has been demonstrated amply in several locations, using various sizes and lengths of pipelines. Considerable research activities on capsule pipelines have been ongoing in several places, including Japan, Australia, South Africa, the Netherlands, and the United States (25). The University of Missouri, Columbia, has the only research center and testing facilities devoted to capsule pipelines in the United States and has a 131-m, 203-mm dia test capsule pipeline devoted to this activity. The concept has been expanded to include a coal log pipeline.

The coal log pipeline involves forming logs of coal by compressing and extruding finely divided coal into cylindrical shapes having a diameter 90–95% the diameter of the pipeline. The coal logs are then injected continuously into a water-filled pipeline for transport by the flowing water. The log length is between 1.5 and 3 times the log diameter and buoyancy is achieved at a water flow rate of 2.4–3.0 m/s. This reduces the energy required for pumping, as well as the friction between coal log and pipeline walls. The coal log pipeline is said to use only one-third as much water for coal transport as coal slurry pipelines, in addition to eliminating the dewatering step. No full-scale coal log pipeline has been built, but short test lines and research activities continue, and a Coal Log Pipeline Consortium has been formed, with both private companies and governmental agencies participating (34).

4. Pipeline Technology

Pipeline technology involves design, construction, maintenance (qv), and operation. Although certain aspects of the technology differ under different climatic conditions, whether above or below ground or under water, etc, the basic steps are the same for liquids pipelines as for gas pipelines.

4.1. Design

Pipeline design begins with a preliminary mapping of the proposed route, noting areas to be avoided and such obstacles as rivers, railroads, and highways. For cross-country pipelines, aerial and ground-control surveys are made to establish the final alignment of the pipeline. Permission to cross all land parcels must be obtained from landowners, and permits obtained from the proper authorities to cross rivers, highways, and railroads; where permission is not obtained, appeal is made to the courts under the right of eminent domain. Approval for gas pipeline construction must be obtained from FERC and/or state public utility commissions, and an environmental impact statement must be filed. Liquid pipelines do not require FERC approval for construction;

common carrier pipelines are generally accorded the right of eminent domain and are regulated by FERC or state authority.

While detailed routing is being established, mechanical design begins by establishing pipe size, based on the volume and type of material being transported, design pressures, pipeline length, and spacing between compressor or pumping stations. The strongest steel possible is used and pipe wall thickness is determined by a code-specified design formula that recognizes pipe as an unfired pressure vessel; the design formula for natural gas pipelines is given by the industry code ASME B31.8 and also by federal regulation 49 CFR 12. For steel pipe, the formula is as follows:

$$P = (2St/D) \times F \times E \times T$$

where P = design pressure in kPa (psig), and may be limited per federal standard 192-105 to 75% of the pressure if steel pipe has been subjected to cold expansion to meet the specified minimum yield strength (SMYS) and then heated to 482°C or held above 316°C for more than 1 h, other than by welding; S = yield strength in kPa (psig); t = nominal wall thickness in mm (in.); F = design factor, which is 0.72 in rural areas and 0.40 in urban areas, with intermediate values of 0.60 and 0.50 for gas lines and 0.72 for liquid lines; E = longitudinal joint factor, which depends on the type of pipe weld seam and is 1 if seam strength equals pipe strength; T = temperature derating factor, which is 1 for operating temperatures of 121°C or less but <1 for higher temperatures, such as at compressor discharge; and D = nominal outside diameter in mm (in.).

This formula determines only the primary pipe (hoop) stress caused by the internal fluid pressure perpendicular to the pipe wall; however, it also recognizes secondary hoop stress through the design factor, F, which represents a safety factor. The maximum design factor of 0.72 recognizes the secondary stresses caused by the load of the overburden against an imperfect trench bottom, those produced by thermal expansion or contraction against earth constraint on buried pipe, and others. The design factor is lowered in populous areas to provide additional safety and to recognize additional stresses in those areas compared with rural areas; it is also lowered for installations at river crossings, highways, etc. The maximum allowable operating pressure (MAOP) of the pipeline can be affected by the pipe mill test pressure level and/or the hydrostatic strength test after construction is complete; either could underrate the pipeline. Longitudinal primary tensile stresses are half of the primary hoop stress. Specifications for valves, fittings, etc, must be written as part of the design phase. Shut-off valves are required at specific intervals to isolate any pipeline damage; powered valve-closing devices are commonly installed to shut off valves automatically in the event of a line break and isolate the damaged portion of the line. Valves on cross-country pipelines should be of a full round-opening design to permit passage of devices, called pigs, for line cleaning, separating water from gas during hydrostatic testing, corrosion detection, etc. Specifications are made for exterior coatings and cathodic protection to minimize external corrosion, and for interior coatings or additives to minimize interior corrosion, as well as decrease flow resistance and improve transmission of odorants. Interior pipe coatings are usually epoxy paints applied before pipeline assembly.

Spacing between compressor/pumping stations is usually 80–160 km along the pipeline to boost pressure lost to internal friction by the gas or liquid being transported. The compressors/pumps are driven by either reciprocating internal combustion gas engines of up to 4.5 MW (6000 hp), centrifugal gas turbines of up to 11.2 MW (15,000 hp), or electric motors of up to 7.5 MW (10,000 hp). A compressor/pumping station usually consists of several compressors/pumps operating in parallel.

4.2. Construction

Pipeline construction is a continuous activity required by supply changes due to decreasing production from older fields, opening up new fields, or bringing in new supplies from Canada; obsolete pipelines are decommissioned, additions are made to existing pipelines, or new pipelines are designed and laid to take advantage of new supply sources. Construction of a cross-country pipeline may be divided into segments (spreads) and proceeds by the following steps: right-of-way clearing and grading, trenching, pipe stringing along the right-of-way, pipe bending to fit the trench bottom, welding, cleaning and priming the exterior surface for coating, coating and wrapping for cathodic protection unless it is mill-coated and only the weld areas need coating, lowering pipeline into trench, and backfill of earth over the pipeline.

Alternative construction methods are used for crossing obstacles. For river crossings, floats may be used to carry the pipe across the river with concrete coatings or weights, flooding the floats to sink the pipe to the river bottom where the weights hold it in place. Land under highways is bored with an earth auger followed closely by the pipe or casing, if required, advanced by the same machine. With advances in horizontal directional drilling, bored river or wetlands crossings of up to 762 m of bore have been made.

When construction is complete, the pipeline must be tested for leaks and strength before being put into service; industry code specifies the test procedures. Water is the test fluid of choice for natural gas pipelines, and hydrostatic testing is often carried out beyond the yield strength in order to relieve secondary stresses added during construction or to ensure that all defects are found. Industry code limits on the hoop stress control the test pressures, which are also limited by location classification based on population. Hoop stress is calculated from the formula, $S = PD/2t$, where S is the hoop stress in kPa (psig); P is the internal pressure in kPa (psig), and D and T are the outside pipe diameter and nominal wall thickness, respectively, in mm (in.).

Tests of cross-country pipelines are recommended at 90% of pipe yield strength in order to avoid having insufficient field-test pressure, which can limit the MAOP of the pipeline to less than that calculated by the design formula. According to industry code, this can be achieved only by hydrostatic testing with nonflammable liquid, such as water. Filtered water is used to displace air left in the line during construction; a pipeline pig separates the two phases and eliminates air pockets. The water is pressurized to produce the hoop stress desired and is recommended to be held for a minimum of 8 h to test pipe strength. When the test is finished, the water is displaced by the pressurized fluid for which the line was built, ie, natural gas, crude oil, etc. A pig is used to separate the two phases and remove accumulated water at low points; for natural gas pipelines, multiple pigs also remove water retained on pipe walls that could cause operational problems. The pipeline is tied in to distribution and supply systems, if it passes the tests, and put into service. The final step is a cleanup and posting of required location markers.

Construction of underwater (submarine) pipelines does not take place under water. Pipelines are welded onshore and dragged into position by powerful winches on ships floating on the water surface (for short lines), welded on a specially constructed lay barge, and lowered to the ocean floor by a stinger from one end of the barge or welded onshore, floated on pontoons, and towed to the offshore area where they are lowered into position. For smaller size pipelines, the lines can be welded onshore and spooled onto large reels, placed on special ships, and spooled into the offshore trench. In shallow water, or where endangered by anchors or wave action, submarine pipelines are laid in trenches in the sea bottom (35). Underwater pipelines are concrete-coated or weighted to overcome the buoyancy effect; concrete coatings applied over the primary coating provide additional protection against damage during laying and against corrosion. Submarine pipelines are being used regularly to transport oil, natural gas, and other commodities to shore from offshore locations, such as the Gulf of Mexico, the North Sea, and the Arabian Gulf. One of the longest and technically challenging submarine pipeline systems is a 2599-km, 1200-mm dia pipeline for transporting natural gas across the Mediterranean Sea and the Strait of Messina from gas fields in Algeria to Italy; pipes are laid in water depths to 610 m. Offshore and onshore pipelines require different design factors (36).

4.2.1. Trenchless Construction

Increased emphasis on environmental and ecological factors has presented considerable difficulties for normal pipeline trenching, even in unpopulated areas, if considered harmful to wildlife in their native habitats. In densely populated areas, trenching is costly and complex because of airports, commercial buildings, factories, etc. To circumvent them, trenchless procedures are being developed for installing fuel lines, water lines, sewer pipe, etc, or in some cases for steel casings that can serve as conduits for several smaller diameter pipe systems. Horizontal directional drilling is a trenchless construction technique that drills under an obstacle, such as a street, airport runway, or river, and the welded continuous steel pipeline segment is pulled through the opening after horizontal drilling is complete. Another procedure that was used in Berlin to put a large-diameter casing under a railway embankment between a train station and the River Spree (37) involves the use of pneumatic pipe ramming to ram the steel pipe through the soil. Trenchless construction is used commonly for small gas distribution lines.

Microtunneling involves sinking of two vertical shafts, large enough to lower a horizontal drilling machine to the level from which to dig a tunnel between the two vertical shafts to accommodate the pipeline. The technique has proved useful for installing or rehabilitating sewer pipe systems and often includes the sinking of additional shafts to provide access to the moling (horizontal drilling) machines. Microtunneling was originally and principally developed in Europe, but variations are being developed in both the United States and Japan, and costs are expected to drop rapidly with expanded usage (38).Houston and Dallas are among the U.S. cities that have applied this technique to revitalize underground utilities infrastructures (39–41).

4.3. Maintenance

4.3.1. Pipeline Pigging

After construction, a pipeline must be tested, inspected, cleaned, mapped for bends, dents, or ovalties, maintained during operation, and monitored for leaks or corrosion to ensure safety of operation. These operations involve pigging, moving devices called pigs through the pipeline that can carry out these missions. These may be sophisticated electronic devices or something as simple as a rubber ball pumped through the pipeline to displace fluids (42).

Modern pipeline pigging applications begin with the commissioning of a pipeline when pigs are first used to remove air prior to hydrostatic testing and then used to remove any water left after the testing. A gauging (caliper) pig is used to locate any dents or buckles resulting from the laying or backfilling operations. Special cleaning pigs are used to remove scale, dirt, etc, from interior walls. If the pipeline transports multiple products, pigs can be used to separate them at the liquid interfaces. To prevent loss of pipeline efficiency or increased corrosion due to deposits of wax, scale, or bacteria, the deposits are removed with brush pigs or even more sophisticated pin-wheel pigs that remove deposits to a precise depth (43, 44). Smart or intelligent pigs involving electronic sensor interfaces with computers and miniature video cameras (45), ultrasonics, magnetic-flux leakage, etc, have been developed to inspect pipeline interiors for integrity, metal loss, corrosion, and other defects; however, some pipelines have physical limitations that do not accommodate smart pigs. The potential of smart pigs to improve pipeline safety is considered to be so great that the Office of Pipelines Safety published a ruling that would require modification of pipelines to permit their use where feasible or practical; however, many petitions for reconsideration were filed and a limited suspension of compliance has been granted while the situation is under study (46). Several pigging operations can be put into a single train (47).

4.3.2. Corrosion

Anticorrosion measures have become standard in pipeline design, construction, and maintenance in the oil and gas industries; the principal measures are application of corrosion-preventive coatings and cathodic protection for exterior protection and chemical additives for interior protection. Pipe for pipelines may be bought with a variety of coatings, such as tar, fiber glass, felt and heavy paper, epoxy, polyethylene, etc, either pre-applied or coated and wrapped on the job with special machines as the pipe is lowered into the trench. An electric detector is used to determine if a coating gap (holiday) exists; bare spots are coated before the pipe is laid (see Corrosion and corrosion control).

Cathodic protection is provided by inducing an electric current on the pipeline to ensure that the electric potential of the metallic pipe is less than the earth surrounding the pipeline after it is laid, by using a sacrificial anode bed with a more electropositive metal than iron, or by thermoelectric protection, using heat to generate a direct current to lower the potential of the pipe. Inducing an electric current involves the use of a rectified alternating current to lower the potential of the pipe relative to the ground, which also provides a way to monitor the system by an aerial pipeline survey. Pulsating the direct current produces a magnetic field with a strength proportional to the current flowing in the pipe; using field coils to measure the magnetic field strength provides a method of monitoring the current, even for underground pipe. If the survey indicates that the magnetic strength is reduced over any segment of the pipeline, it would indicate change of potential and current loss, such as would occur with a hole in the pipeline coating, an electric casing short, a separated coupling, or other event that would permit corrosive action (48).

U.S. Department of Transportation (DOT) statistics on liquids pipelines operated under the *Code of Federal Regulations* (49) indicate that corrosion was the second largest contributor to accidents and failures for the period from 1982 to 1991. These statistics covered an average of 344,575 km of liquids pipelines and were derived from required reports to DOT on all pipeline accidents involving loss of at least 7.95 m^3 of liquid, death or bodily harm to any person, fire or explosion, loss of at least 0.8 m^3 of highly volatile liquid, or property damage of $5000 or more (50). Similar results were also reported for 1991 in the 1992 DOT/OPS report on both oil and gas pipeline incidents; 62 out of 210 oil pipeline incidents were due to corrosion, of which 74% were due to external corrosion (43). For gas pipelines, 16 of all 71 reported incidents were due to corrosion, of which 63% were reported as due to internal corrosion; however, internal corrosion of gas pipelines is likely only if CO_2 and H_2O and/or H_2S are present, as with unprocessed gas in gathering lines.

4.4. Operation

Operations are controlled from a central computerized office that maintains communication with compressor stations and flow stations along the route; reports are also received from weekly or biweekly aircraft flyovers to inspect for potentially threatening conditions, such as soil erosion, floods, approaching excavation, or any external evidence of leaks. Flow computers along the pipeline route monitor and quantify flow from producers entering the pipeline or flow leaving the line to customers. Pipeline flow, pressure, and other operating variables can be controlled by commands to compressor stations. In systems that have remote control of main-line valves, central control can isolate sections of pipelines with reported or threatened problems and dispatch personnel to the site. If patrols detect indications of significant increases in population density in specific areas, the safety factor in the design formula may be increased in accordance with industry code, and the maximum allowable operating pressure in those areas is reduced. Operations and maintenance of pipelines are also covered in ASME B31.8 and federal regulation 49 CFR 192.

Cross-country gas pipelines generally must odorize the normally odorless, colorless, and tasteless gas in urban and suburban areas, as is required of gas distribution companies. Organosulfur compounds, such as mercaptans, are usually used for this purpose, and code requires that the odor must be strong enough for someone with a normal sense of smell to detect a gas leak into air at one-fifth the lower explosive limit of gas–air mixtures. The latter is about 5%, so the odorant concentration should be about 1%, but most companies odorize more heavily than this as a safety precaution.

5. Economic Aspects

Pipelines usually represent the least costly way to move fluid products, including solid slurries, wherever they compete with truck or rail transportation. Comparing the transport costs for removing municipal sludge in the former Soviet Union shows a surprising similarity to a similar comparison of transport costs for moving

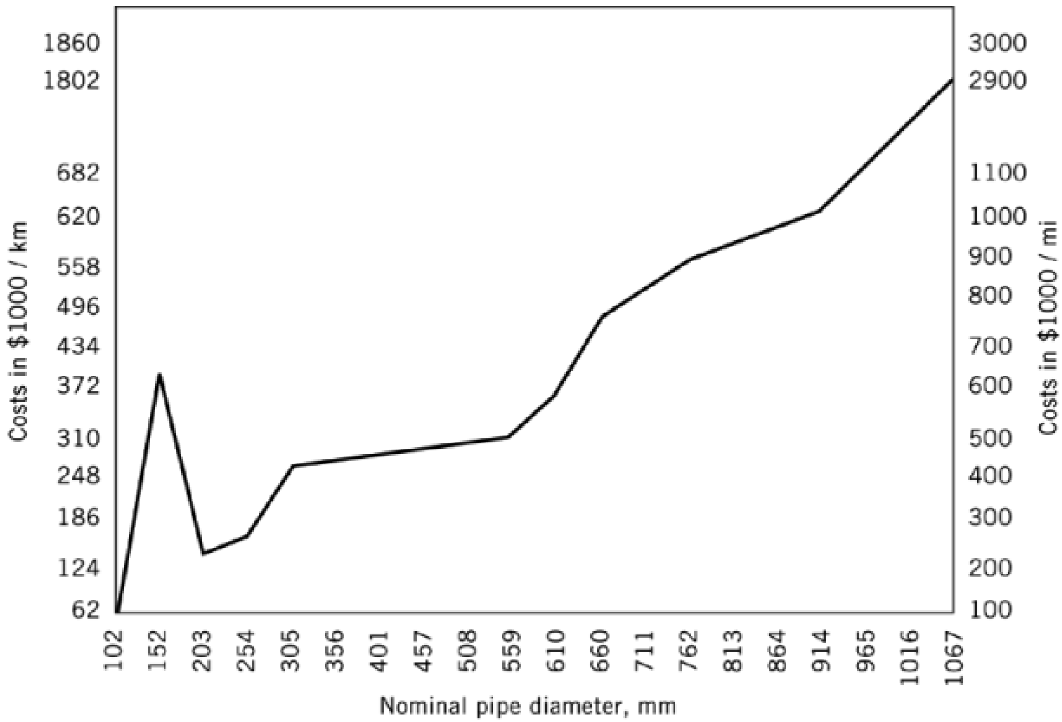

Fig. 2. Gas pipeline construction cost vs pipe size.

U.S. crude oil and petroleum (qv) products. The Russian study (26) showed that pipeline transport of sludge is equal to 25–38% the cost of barge transportation, 6–13% the cost of rail transport, and 4–5% the cost of truck hauling. By comparison, pipeline cost/km of moving crude oil and petroleum products in the United States has been only about 17% of rail costs and 3.5% of truck transport costs (26, 51).

The cost of building a pipeline is usually divided into four categories: materials (line pipe, fittings, coatings, cathodic protection, etc), right-of-way and damages, labor, and miscellaneous (surveying, engineering, supervision, administration and overhead, interest, contingencies, afudc, and FERC filing fees). The relative contribution of each category depends on the size of pipe, the difficulty of terrain, and delays and added costs due to environmental factors, but generally the costs for materials and labor account for about 75% of the entire cost of the pipeline, with each accounting for about half this amount. The remainder is engineering, overhead, fees, interest, etc. The relative contribution of each category can vary widely in difficult terrain or climate, however, as illustrated by the high labor costs of the Trans-Alaska Pipeline, which were 69.3% of the total, and ca $\$1.3 \times 10^9$ interest charges during construction or roughly 15% of the total pipeline cost (52).

The variation of average pipeline construction costs with increasing size of line pipe is shown in Figure 2, based on data taken from FERC construction permit applications from July 1991 to July 1992. The cost of a common carrier pipeline project must be reported to the FERC no later than six months after successful hydrostatic testing.

The 10-yr construction costs for land-based gas pipelines show no obvious trend either in the four individual categories or the high–low range, on a $/km basis; however, pipeline land acquisition costs rose steadily, with average $/km cost increasing from $370,881 to $528,355 for proposed U.S. gas pipeline projects over the 1990–1992 period. The $/km costs for 1991–1992 were material, $190,379; labor, $200,127; right-of-way (ROW) and damages, \$21,938; and miscellaneous, \$115,930 (4). The cost of compressor stations for the same period averaged \$1894/kW.

When a natural gas pipeline has been commissioned and is operating, its transmission costs are the operating expenses plus maintenance expenses. In 1989, these two cost elements for gas pipelines were \$13,573/10^6 m^3 and \$2872/10^6 m^3, respectively; for 1990, the corresponding values were \$17,669/10^6 m^3 and \$3851/10^6 m^3, respectively. The primary operating expense for natural gas pipelines is the cost of compression and gas transmission by others, which accounted for ca 40% of the 1989–1992 expenses. The next largest operating expenses were compressor station labor and expenses, and gas for compressor fuel, accounting for 30% of the total (4). Pigging and testing costs depend on pig type, pipeline cleanliness and diameter, extent of corrosion, etc. The Government Accounting Office survey shows a range of \$404–\$1492/km for the cost of smart pig inspections; a similar survey of three foreign smart pig manufacturers indicated a range of \$746–2486/km for a 1609-km, 610-mm dia pipeline. Hydrostatic test costs are even higher; estimates by the U.S. DOT are \$2890/km for a 508-mm dia hazardous liquids pipeline; this cost rises to \$5523–8794/km if costs of transporting, testing, and disposing of the test water and the revenue loss due to the pipeline being out of service are added. The cost of pressure testing and transportation or disposal of test water is about \$6563/km of pipeline, depending on the pipeline diameter, the terrain crossed, and water scarcity in the area (46).

6. Safety, Environmental, and Ecological Aspects

Data compiled by the U.S. DOT indicate that pipeline transport is the safest materials transport mode, particularly over long distances. In 1990, fatalities attributed to oil and gas pipelines were significantly lower (8 out of 4679) for all materials transporters in the United States, compared with 599 for rail transport and 3281 for motor transport (trucks) (53).

To ensure the safety of gas pipelines, the Natural Gas Safety Act of 1968 was created to mandate federal regulation of gas storage facilities and pipeline transport of natural gas, with the U.S. Department of Transportation given exclusive authority to regulate safe operation of natural gas pipeline systems that fall within the jurisdiction of the Federal Power Commission under the Natural Gas Act. The Hazardous Liquid Pipeline Safety Act of 1979 and the Hazardous Materials Transportation Act of 1979, and their respective amendments, gave authority for the U.S. DOT to regulate safety for all pipelines operating under the *Code of Federal Regulations* (49). The U.S. DOT continues to regulate safety on pipelines and has established legal standards for all pipeline phases, from design to construction, operation, and maintenance. DOT also issues statistics on pipeline accidents from required reports on accidents involving release of gas or LNG and death or hospitalization or losses in excess of \$5000.

Between 1985 and 1991, 1726 natural gas pipeline ruptures and leakages were reported in the United States. These incidents resulted in 634 injuries and 131 fatalities. Third-party damage was the most common cause of these incidents, followed by corrosion. The GAO believes that the corrosion-related incidents can be reduced with the use of smart pigs (46). U.S. DOT 1992 accident statistics showed that 52.5% of U.S. oil spills involving loss of at least 1590 m^3 came from pipeline accidents, comparable to the worldwide statistic of 51.5%. The U.S. DOT regulated 344,575 km of liquids pipelines during the 10-yr study period and received reports on 1901 accidents during that time; thus the number of failures per year per 1000 miles was 0.888, of which 27% was due to corrosion and 31% to outside forces (48).

Most ecological issues involve the pipeline's construction phase and the effect that it will have on vegetation, wildlife, topography, population density, and land use. All pipeline design and construction programs must include an environmental impact statement which must be submitted and evaluated before permission to proceed with construction is granted. Construction through ecologically sensitive obstacles, such as rivers and wildlife areas, is often suspended during certain times of the year, such as fish spawning and wildlife migration seasons, unless acceptable alternatives can be found. Archaeological concerns must also be addressed.

Greater natural gas use for power generation and vehicular fuel use, to help meet more stringent environmental standards, is expected to expand natural gas pipeline usage. High technology will influence the role of post-Order 636 gas pipelines (54). Pipeline transport of coal could become a reality in the United States, as well as other coal-rich countries, to reduce dependence on imported oil. Greater use of freight pipelines to reduce pollution from trucks and other transportation modes may arise (25). Pipeline research activities are expected to expand through organizations such as Japan's National Pipeline Research Society and the Capsule Pipeline Research Center and Gas Research Institute in the United States.

The concept of transporting heat over great distances with chemical energy pipelines has been considered (55).

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