Argonne NATIONAL LABORATORY

ANL/EVS/TM/08-5

Natural Gas Pipeline Technology Overview

Environmental Science Division

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Natural Gas Pipeline Technology Overview

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November 2007

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NOTATION

The following is a list of the acronyms, initialisms, and abbreviations (including units of measure) used in this document. Acronyms and abbreviations used only in tables and figures are defined in the respective tables and figures.

ACRONYMS, INITIALISMS, AND ABBREVIATIONS

AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
ASTM	American Society of Testing and Materials, now ASTM International
BLS	Bureau of Labor Statistics
BMP	best management practice
CEC	California Energy Commission
CFR	*Code of Federal Regulations*
CO	carbon monoxide
DI&M	directed inspection and maintenance
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EIA	Energy Information Administration (DOE)
EPA	U.S. Environmental Protection Agency
ESD	emergency shutdown
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
GPO	U.S. Government Printing Office
HAPs	hazardous air pollutants
HC	hydrocarbon
HDD	horizontal directional drilling
IMP	Integrity Management Plan
INGAA	Interstate Natural Gas Association of America
LCM	logic control module
LNG	liquefied natural gas

MCC	motor control center
NACE	National Association of Corrosion Engineers, now NACE International
NGA	Natural Gas Act
NO_x	nitrogen oxides
NPC	National Petroleum Council
NTSB	National Transportation Safety Board
OPS	Office of Pipeline Safety (DOT)
OSHA	Occupational Safety and Health Administration
PM_{10}	particulate matter less than 10 micrometers in diameter
PSD	prevention of significant deterioration
PUC	Public utility commission
ROW(s)	right(s)-of-way
RTU	remote terminal unit
SCADA	supervisory control and data acquisition
SO_2	sulfur dioxide
TAPS	Trans-Alaska Pipeline System
TSP	total suspended particulate
USACE	U.S. Army Corps of Engineers
VOC	volatile organic carbon

UNITS OF MEASURE

gal	gallon(s)
hp	horsepower
lb	pound(s)
psia	pound(s) per square inch absolute
psig	pound(s) per square inch gauge

1 NATURAL GAS PIPELINE COMPONENTS

1.1 CHARACTERIZATION OF THE INDUSTRY

The United States relies on natural gas for one-quarter of its energy needs. In 2001 alone, the nation consumed 21.5 trillion cubic feet of natural gas. A large portion of natural gas pipeline capacity within the United States is directed from major production areas in Texas and Louisiana, Wyoming, and other states to markets in the western, eastern, and midwestern regions of the country. In the past 10 years, increasing levels of gas from Canada have also been brought into these markets (EIA 2007).

The United States has several major natural gas production basins and an extensive natural gas pipeline network, with almost 95% of U.S. natural gas imports coming from Canada. At present, the gas pipeline infrastructure is more developed between Canada and the United States than between Mexico and the United States. Gas flows from Canada to the United States through several major pipelines feeding U.S. markets in the Midwest, Northeast, Pacific Northwest, and California. Some key examples are the Alliance Pipeline, the Northern Border Pipeline, the Maritimes & Northeast Pipeline, the TransCanada Pipeline System, and Westcoast Energy pipelines. Major connections join Texas and northeastern Mexico, with additional connections to Arizona and between California and Baja California, Mexico (INGAA 2007).

Of the natural gas consumed in the United States, 85% is produced domestically. Figure 1.1-1 shows the complex North American natural gas network.

The pipeline transmission system — the "interstate highway" for natural gas — consists of 180,000 miles of high-strength steel pipe varying in diameter, normally between 30 and 36 inches in diameter. The primary function of the transmission pipeline company is to move huge amounts of natural gas thousands of miles from producing regions to local natural gas utility delivery points. These delivery points, called "city gate stations," are usually owned by distribution companies, although some are owned by transmission companies. Compressor stations at required distances boost the pressure that is lost through friction as the gas moves through the steel pipes (EPA 2000).

The natural gas system is generally described in terms of production, processing and purification, transmission and storage, and distribution (NaturalGas.org 2004b). Figure 1.1-2 shows a schematic of the system through transmission. This report focuses on the transmission pipeline, compressor stations, and city gates.

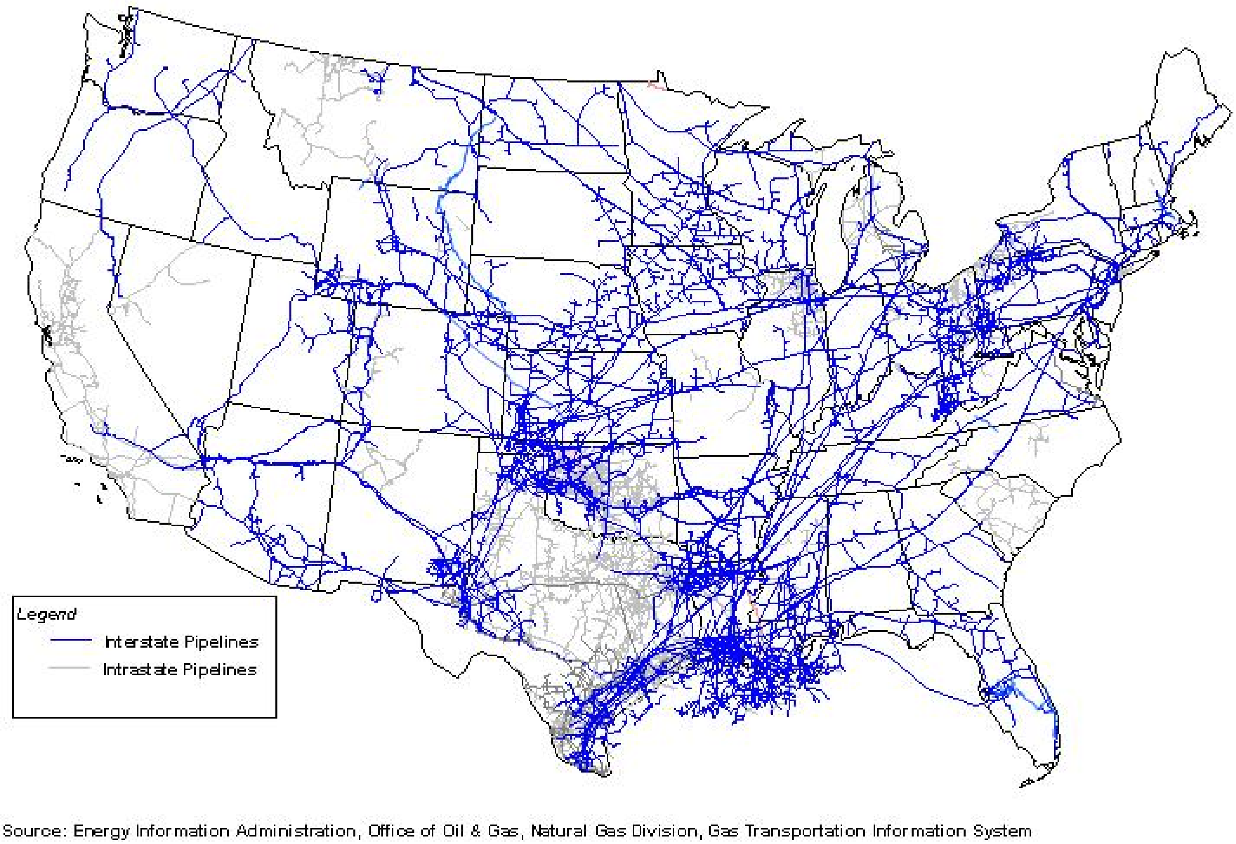

FIGURE 1.1-1 U.S. Natural Gas Pipeline Network (Source: EIA[1])

1.2 NATURAL GAS TRANSMISSION SYSTEM

The transmission segment of the gas industry is responsible for transporting natural gas from the producer to the market areas via pipelines. The transmission system is composed of pipelines, compressor stations, city gate stations, and storage facilities.

1.2.1 Transmission Pipelines

Transmission pipelines are made of steel and generally operate at pressures ranging from 500 to 1,400 pounds per square inch gauge (psig). Pipelines can measure anywhere from 6 to 48 inches in diameter, although certain component pipe sections can consist of small-diameter

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1 The EIA has determined that the informational map does not raise security concerns, based on the application of the Federal Geographic Data Committee's *Guidelines for Providing Appropriate Access to Geospatial Data in Response to Security Concerns*.

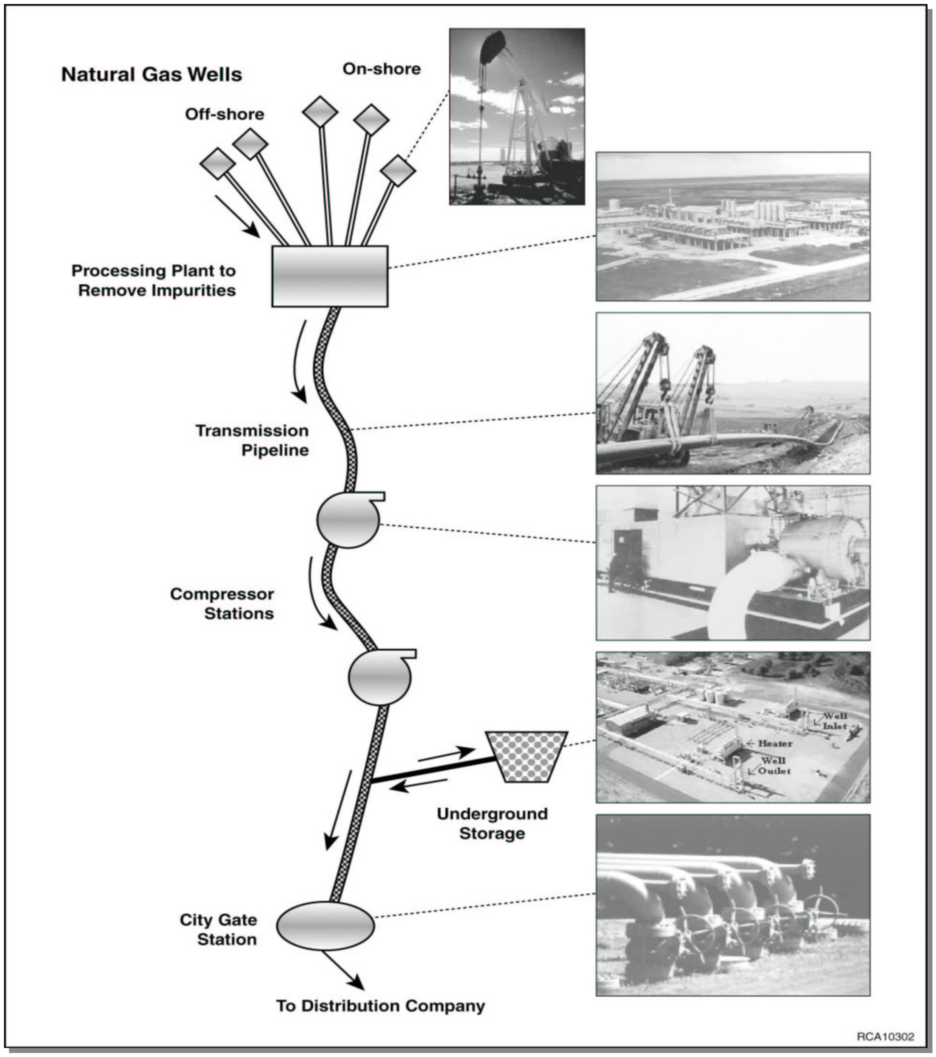


FIGURE 1.1-2 Schematic of Natural Gas Production, Processing, Transmission, and Storage (Source: Cirillo et al. 2003)

pipe that is as small as 0.5 inch in diameter. However, this small-diameter pipe is usually used only in gathering and distribution systems, although some is used for control-line or gauge-line purposes. Mainline pipes, the principal pipeline in a given system, are usually between 16 and 48 inches in diameter. Lateral pipelines, which deliver natural gas to or from the mainline, are typically between 6 and 16 inches in diameter. Most major interstate pipelines are between 24 and 36 inches in diameter. The actual pipeline itself, commonly called “line pipe,” consists of a strong carbon steel material engineered to meet standards set by the American Petroleum Institute (API), American Society of Testing and Materials (ASTM), and American National Standards Institute (ANSI).

Line pipe is produced in steel mills, which are sometimes specialized to produce only pipeline-quality components. There are two different production techniques, one for small-diameter pipes and one for large-diameter pipes. For large-diameter pipes, from 20 to 42 inches in diameter, the pipes are produced from sheets of metal that are folded into a tube shape, and the ends are welded or fused together to form a pipe section. Small-diameter pipe, on the other hand, can be produced seamlessly. This technique involves heating a metal bar to very high temperatures and then punching a hole through the middle of the bar to produce a hollow tube. In either case, the pipe is tested before being shipped from the steel mill to ensure that it can meet the pressure and strength standards for transporting natural gas.

Pipelines are usually buried underground; the burial depth varies depending on the local geography along the pipeline route. Normal depth requirements are 2 to 4 feet to top of pipe. Many transmission pipeline companies transport gas to metropolitan markets. Figure 1.2-1 shows the installation of a typical transmission pipe in a remote location.

It should be noted that the average diameter of a natural gas transmission pipeline in the western states is around 20 inches with an average length of around 11 miles per segment between line valves. There are approximately 68,000 miles of transmission pipelines in this region (based on Platts 2005 *PowerMap* data).

1.2.1.1 Pipe-Coating Materials

Coating mills apply pipe coatings to ensure that the pipe does not corrode once placed in the ground. Often, the coating mill is located adjacent to the pipe mill, so line pipe moves directly from the pipe manufacturer to the coating facility. The purpose of the coating is to protect the pipe from moisture, corrosive soils, and construction-induced defects, which cause corrosion and rusting. There are a number of different coating techniques. In the past, pipelines were coated with a specialized coal tar enamel. Today, pipes are often protected with a fusion-bond epoxy or extruded polyethylene, both of which give the pipes a noticeable light yellow color. In addition, cathodic protection is often used, which is a technique that involves inducing an electric current through the pipe to ward off corrosion and rusting (AGA 2004).

To prepare for fusion-bond epoxy coating, the external surface of the pipe is thoroughly cleaned with a shot-blast process. The pipe is then heated to a prescribed temperature, and an epoxy powder is applied. The powder “melts” onto the heated pipe and forms a water-tight barrier. The mill tests the coated pipe (called “jeeping”) with high voltage to evaluate the coating’s insulating effectiveness prior to transporting the pipe to the job site.

1.2.1.2 Compressor Stations

Natural gas is highly pressurized as it travels through an interstate pipeline to expedite the flow of gas. To ensure that the natural gas flowing through any one pipeline remains pressurized, compression of the natural gas occurs periodically along the pipe. This is accomplished by compressor stations, which are usually placed at 40- to 100-mile intervals along the pipeline. The natural gas enters the compressor station, where it is compressed by either a turbine, motor, or engine.

FIGURE 1.2-1 Typical Installation of a Large Transmission Natural Gas Pipe (Source: Argonne Staff)

Turbine compressors gain their energy by using up a small proportion of the natural gas that they compress. The turbine itself serves to operate a centrifugal compressor, which contains a type of fan that compresses and pumps the natural gas through the pipeline. Some compressor stations are operated by using an electric motor to turn the same type of centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipe; however, it does require that a reliable source of electricity be located nearby. Reciprocating natural gas engines are also used to power some compressor stations. These engines resemble very large automobile engines, and are powered by natural gas from the pipeline. The combustion of the gas powers pistons on the outside of the engine, which serve to compress the natural gas.

In addition to compressing natural gas, compressor stations usually contain some type of liquid separator, much like those used to dehydrate natural gas during its processing. Usually these separators consist of scrubbers and filters that capture any liquids or undesirable particles from the natural gas in the pipeline. Although natural gas in pipelines is considered a dry gas, it is not uncommon for a certain amount of water and hydrocarbons to condense out of the gas stream while in transit. The liquid separators at compressor stations ensure that the natural gas in the pipeline is as pure as possible, and usually filter the gas prior to compression.

Compressor stations are powered by compressors that are each rated at several thousand horsepower (hp). The stations contain valves, pipes, and control systems that monitor the functioning and operating parameters of the system. Most compressor stations are fully automated. Figure 1.2-2 provides an aerial view of a natural gas pipeline compressor station along a major transmission pipeline system. The compressors are typically housed in a metal

FIGURE 1.2-2 Natural Gas Compressor Station along an Interstate Pipeline (Source: Argonne Staff)

building with pipe appurtenances and other critical elements above ground. All electrical fittings within the metal building are explosion-proof. Figure 1.2-3 shows a close-up of a reciprocating compressor, which is typically housed in a metal building along the pipeline. These stations are monitored or controlled by supervisory control and data acquisition (SCADA) systems.

Based on Platts *PowerMap* data (2005), the average size of an interstate compressor station in the western states is around 13,000 hp, with large variations in size found throughout the western region.

Compressor station facilities are generally sited on 15 to 22 acres of land and include an all-weather gravel access road, the compressor building, cooling fans, a control building, and possibly two or three small auxiliary buildings. The compressor building as well as the piping and equipment are acoustically designed to keep noise to a minimum (Table 1.2-1) and are constructed using explosion-proof electrical fittings.

A natural gas compressor station generates noise on a continuous basis during operations. However, as Table 1.2-1 shows, the noise levels attributable to operations of new compressor stations would not result in significant effects on individuals nearest to the facilities.

A typical compressor station houses the gas turbine compressor package as well as the instrumentation controls and equipment required to monitor and operate the engines and compressors. Compressor stations are typically enclosed by a chain-link fence, and most have some type of additional security equipment such as cameras and motion sensors.

Natural gas piping, both aboveground and belowground, associated with the installation of the interconnections, metering stations, and pigging facilities at a compressor station are installed and pressure-tested using methods similar to those used for the main pipeline. After

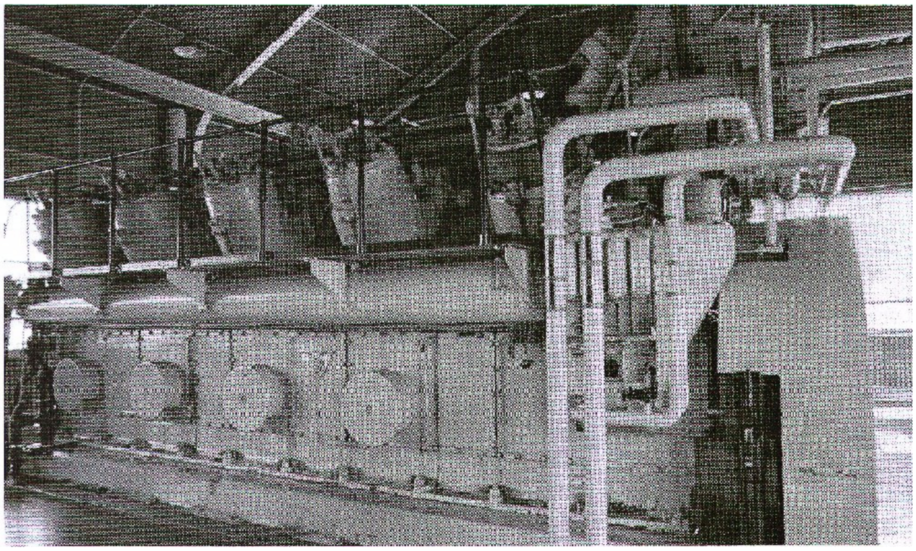


FIGURE 1.2-3 Integrated Reciprocating Natural Gas Compressor (Source: Argonne Staff)

TABLE 1.2-1 Order-Ranked Sound Level Contributions of a Typical Centrifugal Compressor Station at a Nearby Noise-Sensitive Area

Noise Source/Path	Unattenuated	Attenuated Design[a]
Power turbine exhaust	54	37 (17)
Yard piping	52	37 (15)
Make-up air louvers	48	37 (11)
Building walls and roof	46	37 (9)
Air-cooled heat exchanger	44	37 (7)
Lube oil cooler	36	36
Suction scrubber	34	34
Gas generator inlet	32	32
Building piping	30	30
Sum	57	45
Design criteria	45	45
Noise reduction required	12	0

[a] Values in parentheses depict the result of noise-reduction technology.

Source: Frank (1994).

testing is successfully completed, the piping is tied into the main pipeline. Piping installed below grade is coated for corrosion protection prior to backfilling. In addition, all below-grade facilities are protected by a cathodic protection system. Before being put into service, compressors, controls, and safety devices are tested to ensure proper system operation and the activation of safety mechanisms (including disaster automatic or manual shutdown), as necessary (CEC 2007).

Other major equipment installed at each site includes aerial gas coolers, fuel gas skids, the motor control center (MCC) and control building skids, logic control module (LCM) skids, and filter houses. The primary contractor typically works on concrete foundations; pipe fabrication; and pipe, equipment, and structural steel installation and instrumentation. Subcontracted work includes piling; reinforcing steel; earthwork; electrical work; structural steel fabrication; heating, ventilating, and air conditioning; insulation; pipe coatings and painting; and pre-engineered buildings.

1.2.1.3 Metering Stations

Metering stations are placed periodically along interstate natural gas pipelines. These stations allow pipeline and local distribution companies to monitor, manage, and account for the natural gas in their pipes. Essentially, these metering stations measure the flow of gas along the pipeline, allowing pipeline companies to track natural gas as it flows along the pipeline. Metering stations employ specialized meters to measure the natural gas as it flows through the pipeline without impeding its movement. In essence, the metering station is the company's "cash register." Figure 1.2-4 shows a typical meter station.

Meter/regulator stations are generally constructed adjacent to the cleared pipeline right-of-way (ROW) at each of the receipt and interconnect points to meter the flow and adjust the pressure of natural gas received from or delivered to those systems. A meter/regulator station typically includes meter and regulator equipment, a filter separator, odorant equipment, and a control building housed within a fenced perimeter.

FIGURE 1.2-4 Typical Metering Station (Source: U.S. Pipeline, Inc.)

1.2.1.4 City Gate Stations

The natural gas for most distribution systems is received from transmission pipelines and fed through one or more city gate stations, sometimes called *town border* or *tap* stations. The basic function of these stations is to meter the gas and reduce its pressure from that of the pipeline to that of the distribution system. The latter operates at a much lower pressure (reduced from approximately 500–1,400 psig to about 0.25–300 psig). Figure 1.2-5 shows a city gate station that would typically be covered with a fiberglass enclosure or metal building to protect it from the weather.

Most city gate stations measure the gas flow with metering devices and reduce its pressure with pressure regulators. These devices control the rate of gas flow and/or pressure through the station and maintain the desired pressure or flow level in the distribution system. Gas received at city gate stations may or may not contain odorant, the compound that gives odorless natural gas its distinctive smell. Odorant must be added to the gas if it is received with insufficient or no odorant before the gas can leave the city gate station (the odorant concentration is normally three-quarters of a pound per 1 million cubic feet of natural gas).

1.2.1.5 Valves

Interstate pipelines include a great number of valves along their entire length. These valves work like gateways; they are usually open and allow natural gas to flow freely, but they can be used to stop gas flow along a certain section of pipe. There are many reasons why a pipeline may need to restrict gas flow in certain areas, including for emergency shutdown and maintenance. For example, if a section of pipe requires replacement or maintenance, valves on either end of that section of pipe can be closed to allow engineers and work crews safe access. These large valves can be placed every 5 to 20 miles along the pipeline, and are subject to

FIGURE 1.2-5 City Gate Gas Measurement and Regulation Station (Source: Argonne Staff)

regulation by safety codes. Figure 1.2-6 shows a typical large aboveground valve on a natural gas pipeline.

A mainline valve site generally consists of a 40-foot by 40-foot area surrounded by a chain-link fence within the confines of the permanent pipeline ROW. Aboveground elements of each mainline valve site include the piping with its valving that extends above ground for blowoffs (including blowdown stacks, with some sites having permanent silencers attached for noise abatement) and bypass. The mainline valves appear as a small fenced area within a cleared ROW unless the site is in an open field.

1.2.1.6 Pig Launching/Receiving Facilities

Pigging facilities consist of pig launching or receiving equipment and allow the pipeline to accommodate a high-resolution internal inspection tool (Figure 1.2-7). Pigs are devices that are placed into a pipeline to perform certain functions. Some are used to clean the inside of the pipeline or to monitor its internal and external condition. Launchers and receivers are facilities that enable pigs to be inserted into or removed from the pipeline.

A pigging facility is generally smaller than a typical compressor station site, but is typically twice the size of a valve site. It may be equipped with an office, workshops, a small permanent camp (in remote locations), power generators, storage areas, and a helipad. It is normally unmanned except during periods of manual pigging and during routing service or repair.

FIGURE 1.2-6 Aboveground Valve on Natural Gas Pipeline (Source: Cirillo et al. 2003)

FIGURE 1.2-7 Crew Inserting a Pig into a Pipeline (Source: Argonne Staff)

1.2.2 SCADA Centers

Natural gas pipeline companies have customers on both ends of the pipeline — the producers and processors that input gas into the pipeline and the consumers and local distribution companies that take gas out of the pipeline. To manage the natural gas that enters the pipeline and ensure that all customers receive timely delivery of their portion of this gas, sophisticated control systems are required to monitor the gas as it travels through all sections of a potentially very lengthy pipeline network. To accomplish the task of monitoring and controlling the natural gas that is traveling through the pipeline, centralized gas control stations collect, assimilate, and manage the data received from monitoring city gate stations and compressor stations all along the pipeline.

Most of the data that is received by a control station is provided by supervisory control and data acquisition (SCADA) systems. These systems are essentially sophisticated communications systems that take measurements and collect data along the pipeline (usually in metering or compressor stations and valves) and transmit the data to the centralized control station. Flow rate through the pipeline, operational status, pressure, and temperature readings may all be used to assess the status of the pipeline at any one time. These systems also work in real time, so there is little lag time between taking measurements along the pipeline and transmitting them to the control station. Equipment status scans are taken every 6 to 90 seconds depending on the communication technology used in the field (NPC 2001).

This information allows pipeline engineers to know exactly what is happening along the pipeline at all times, which permits quick reactions to equipment malfunctions, leaks, or any other unusual activity along the pipeline, as well as to monitoring load control. Some SCADA systems also incorporate the ability to operate certain equipment along the pipeline remotely, including compressor stations, which allows engineers in a centralized control center to adjust flow rates in the pipeline immediately and easily.

Control and monitoring are conducted by using remote terminal units (RTUs), which are placed at intervals along the pipeline, at compressor stations, city gate/measurement stations, underground storage fields, and other related locations. RTUs periodically collect data from field instruments that measure pressure, temperature, flow, and heat content of the natural gas. The data are transmitted from the RTUs through a communications network that could consist of company-owned fiber-optic lines, leased telephone lines, ground- or satellite-based microwave, or radio communication systems. The SCADA system is monitored 24 hours per day, 365 days a year. SCADA systems allow the pipeline companies to control or shut down portions of a pipeline in the event of an accident or for other safety reasons. They also are used to collect data at different system points as well as to feed data to other administrative function such as billing, marketing, and monitoring cathodic protection systems (at critical pipeline bond interconnect points and rectifiers). Figure 1.2-8 shows a SCADA control center for a major pipeline company.

In all SCADA systems, the master terminal unit and RTUs communicate through a defined network of some type. Early systems used wired communications, either through private hard-wired systems owned by the operator (usually practical only for short distances) or through the public-switched phone network. Today there are still many systems using public phone systems, encompassing both wire and fiber optics technology. These facilities allow remote monitoring of the pipeline and communication with valves, compressors, and personnel during operation.

Most new systems and many retrofits are using some form of wireless communications. Many pipelines own their own microwave infrastructure, including dedicated towers and radio frequencies licensed by the Federal Communications Commission. Systems using frequencies in the very high or ultrahigh frequency (VHF and UHF, respectively) ranges are also in use. These operators may own their own towers or lease space from other operators. Many newer systems are making use of low-power radio transmissions, such as spread-spectrum technology, to avoid the licensing requirements. Satellite communications are also used for long-distance and rugged-terrain communications.

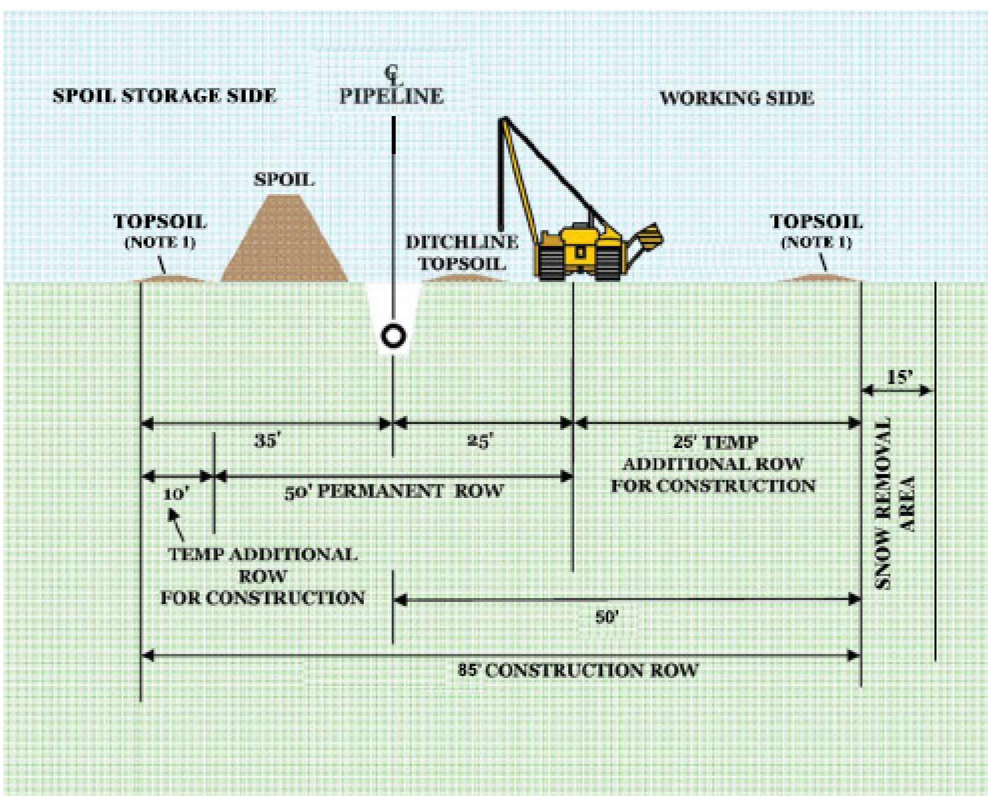
FIGURE 1.2-8 SCADA Center (Source: Argonne Staff)

SCADA systems can also operate on cell phone technology, such as the Cellular Digital Packet Data network, which does not require dedicated lines or other infrastructure such as an antenna tower. Some SCADA systems operate directly through the Internet, eliminating certain maintenance concerns for the operator.

1.2.3 Access Roads

Pipeline companies generally try to use existing roads to provide access to the construction ROW (Figure 1.2-9). The access roads are used on a temporary basis to transport personnel, equipment, vehicles, heavy trucks, and materials to project work areas. Some of these roads may not support heavy construction equipment and, therefore, would be used only for light truck traffic (e.g., pickup trucks).

In most cases, the roads used for pipeline construction and operations are existing paved or graveled public roads that would not require modification unless the road base were to deteriorate and make driving difficult or unsafe for both public and construction traffic. Two-track and dirt roads may require some level of improvement to support construction equipment, vehicles, and ongoing maintenance during the construction period, especially when



Note:
1) This location for topsoil will be required if full width topsoil stripping is required.

FIGURE 1.2-9 Typical Construction ROW (Source: FERC 2005a)

rain or snow occurs and travel over the roads degrades their condition. Road improvements such as blading and filling would be restricted to the existing road footprint (i.e., the road would not be widened) wherever possible and where there is evidence that the road was graded previously. If necessary, the equipment is pulled along the ROW by bulldozers, and the road or property is returned to its original state.

1.3 EXISTING STANDARDS AND REGULATIONS

A number of federal and state agencies have standards and regulations that affect natural gas pipelines, including the following:

- *U.S. Department of Transportation (DOT).* Natural gas pipelines and facilities are governed by Title 49, Part 192, of the *Code of Federal Regulations* (CFR), "Transportation of Natural and other Gas by Pipeline – Minimum Federal Safety Standards." This part prescribes minimum safety requirements for pipeline facilities and the transport of gas, including pipeline facilities and the transport of gas within the limits of the outer continental shelf, as defined in the Outer Continental Shelf Lands Act (43 USC 1331). In addition, 49 CFR Part 195, "Operator Qualification and Certification," is followed for the training and certification of personnel who construct, operate, and maintain the natural gas system. DOT has the responsibility and authority to promulgate and interpret safety standards, inspect companies' adherence to the standards, and enforce these standards through the U.S. Department of Justice or local public utility commissions.

- *Federal Energy Regulatory Commission (FERC).* The FERC is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects. As part of that responsibility, FERC:

  - Regulates the transmission and sale of natural gas for resale in interstate commerce;
  - Regulates the transmission of oil by pipeline in interstate commerce;
  - Regulates the transmission and wholesale sale of electricity in interstate commerce;
  - Licenses and inspects private, municipal, and state hydroelectric projects;
  - Approves the siting and abandonment of interstate natural gas facilities, including pipelines, storage, and liquefied natural gas (LNG);
  - Oversees environmental matters related to natural gas and hydroelectricity projects and major electricity policy initiatives; and
  - Administers accounting and financial reporting regulations and the conduct of regulated companies.

- *Office of Pipeline Safety (OPS).* The OPS (under DOT) is responsible for promoting the safe and environmentally sound operation of natural gas and hazardous liquid pipeline systems. OPS issues and enforces pipeline safety regulations and provides state inspectors and the industry with training and technical assistance. Two statutes provide the primary legal framework for the federal pipeline safety program. The Natural Gas Pipeline Safety Act of 1968, as amended, authorizes DOT to regulate pipeline transport of various gases, including natural gas and LNG. OPS safety jurisdiction over pipelines covers more than 3,000 gathering, transmission, and distribution operators and about 52,000 master meter and LNG operators who own and/or operate approximately 1.6 million miles of gas pipelines, in addition to more than 200 operators and an estimated 155,000 miles of hazardous liquid pipelines. OPS maintains a reporting system for compiling accident- and safety-related condition reports submitted by gas and hazardous liquid pipeline operators, as well as annual reports submitted by gas pipeline operators.

- *National Transportation Safety Board (NTSB)*. The NTSB is an independent federal agency charged by Congress with investigating every civil aviation accident in the United States and significant accidents in the other modes of transportation, including railroad, highway, marine, and pipeline. The NTSB also issues safety recommendations aimed at preventing future accidents. The NTSB determines the probable cause of:

  – Pipeline accidents involving a fatality or substantial property damage,
  – Releases of hazardous materials in all forms of transportation, and
  – Selected transportation accidents that involve problems of a recurring nature.

- *U.S. Coast Guard*. The Coast Guard is involved in a variety of missions, including search and rescue, marine environmental protection, enforcement of laws and treaties, ice operations, drug interdiction, marine safety, and national security. The Coast Guard has assumed one of the lead roles in responding to attacks by providing homeland security in harbors and ports and along coastlines. Commercial, tanker, passenger, and merchant vessels have been subject to increased security measures enforced by the Coast Guard. The agency plays a role in responding to LNG-transport and other emergencies on the nation's navigable waters.

- *Federal Emergency Management Agency (FEMA)*. FEMA is responsible for supporting state and local governments in dealing with disasters that require more than local resources can handle. FEMA becomes involved once the president, at the request of a state's governor, has declared a region a disaster area. Among other things, FEMA coordinates the efforts of federal agencies that assist in declared disasters involving energy, including natural gas disruptions.

- *Public Utility Commission (PUC)*. In addition to the above regulatory agencies, state PUCs have standards and regulations regarding the natural gas infrastructure within their states. In general, the PUCs are responsible for ensuring safe, efficient, reliable, and uninterrupted utility service at reasonable prices; regulating the financial organization of utility companies so that they provide such services; and providing utility companies with the opportunity to earn a reasonable profit.

- *State and Local Fire Departments*. The natural gas industry as a whole normally relies on local fire departments as well as the state fire marshal's office for assistance during an emergency and for planning for emergency procedures.

- Other agencies or organizations that affect the industry are the U.S. Environmental Protection Agency (EPA), U.S. Department of Labor's Occupational Safety and Health Administration (OSHA), ASTM International (originally known as the American Society for Testing and Materials [ASTM]), American Petroleum Institute (API), and NACE International (originally known as the National Association of Corrosion Engineers). Permits may be required for construction through highways and railroads, which would necessitate interaction with the Federal Highway Administration (FHWA) and private railroad companies, respectively.

2 NATURAL GAS PIPELINE CONSTRUCTION

Any proposed natural gas facility is designed, constructed, tested, and operated at a minimum in accordance with all applicable requirements included in the DOT regulations in 49 CFR Part 192, "Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards," and other applicable federal and state regulations. These regulations are intended to ensure adequate protection for the public and to prevent natural gas pipeline accidents and failures. Among other design standards, Part 192 specifies pipeline material and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

2.1 GENERAL PIPELINE CONSTRUCTION PROCEDURES

Before construction starts, engineering surveys are conducted of the ROW centerline and extra workspaces, and complete land or easement acquisition of private and state lands is finalized. If the necessary land rights or easements are not obtained through good faith negotiations with landowners and the project is approved by the FERC, the pipeline company could use the right of eminent domain granted it an easement under Section 7(h) of the Natural Gas Act (NGA). The pipeline company is still required to compensate the landowners for the ROW, as well as for any damages incurred during construction. The pipeline company generally pays the market price for the property. However, the level of compensation is determined by the court system according to state laws regarding eminent domain. Eminent domain is used only as a last resort, because the process can take up to 2 to 3 years (FERC 2007).

The landowner normally is compensated a fair market value for a permanent easement, which typically allows the landowner continued use and enjoyment of the aboveground property, with some limitations. The limitations typically prohibit excavation as well as the placement of structures and trees within the easement to preserve safe access for maintenance equipment when necessary and allow for uninhibited aerial inspection of the pipeline system.

The landowner is generally compensated at an amount lower than fair market value when the pipeline company needs only a temporary construction easement, since this land reverts back to the landowner after construction for full use and enjoyment without any restrictions, although ROW cleanup could continue for several years.

Additionally, landowners are compensated for any damages or losses they may incur, such as the loss of crop revenues, as a result of construction across their property. Normally, they are compensated through several growing seasons.

Overland pipeline construction in a rural environment generally would proceed as a moving assembly line, as summarized below. Typically, job-specific work crews would construct the facilities associated with the compressor stations.

Standard pipeline construction is composed of specific activities, including survey and staking of the ROW, clearing and grading, trenching, pipe stringing, bending, welding, lowering-in, backfilling, hydrostatic testing, tie-in, cleanup, and commissioning. In addition to standard pipeline construction methods, the pipeline company would use special construction techniques where warranted by site-specific conditions. These special techniques would be used when constructing across rugged terrain, waterbodies, wetlands, paved roads, highways, and railroads.

2.1.1 Permits

Prior to construction, a proposed pipeline project must obtain numerous local, state, and federal permits and clearances. The permits address all natural resources — land, air, water, vegetation, and wildlife — as well as the interests of the general public. Requirements generally include:

- *Local*
  - Building permits
  - Road-crossing permits
- *State*
  - Land (Erosion and Sedimentation Permit)
  - Water (Hydrostatic Testwater Acquisition and Discharge Permit, Stormwater Discharge Permit)
  - Stream and river crossings (State Environmental Agency)
  - Cultural resources preservation (State Historic Preservation Office)
  - Threatened and endangered species preservation (State Fish and Wildlife Agency)
  - Air emissions (State Environmental Agency)
  - Highway permits (Federal Highway Administration [FHWA])
- *Federal*
  - Wetlands preservation and crossings (U.S. Army Corps of Engineers [USACE])
  - Streams and rivers (USACE)
  - Threatened and endangered species (U.S. Fish and Wildlife Service)
  - Air emissions (EPA)
  - Environmental resource reports
  - Noise (FERC)
  - Highway permits (FHWA) as well as private company owner permits (such as railroads)

Copies of all permits and permit applications are submitted to FERC prior to beginning construction, if required.

2.1.2 Survey and Staking

The first step of construction involves marking the limits of the approved work area (i.e., construction ROW boundaries, additional temporary workspace areas) and flagging the locations of approved access roads and foreign utility lines. Wetland boundaries and other environmentally sensitive areas also are marked or fenced for protection at this time. Before the pipeline trench is excavated, a survey crew stakes the centerline of the proposed trench.

2.1.3 Clearing and Grading

Before clearing and grading activities are conducted, the landowners' fences (if any) are braced and cut, and temporary gates and fences are installed to contain livestock, if present. A clearing crew follows the fence crew and clears the work area of vegetation and obstacles (e.g., trees, logs, brush, rocks). Grading is conducted where necessary to provide a reasonably level work surface, as shown in Figure 2.1-1. Rootstock is left in the ground in areas where the ground is relatively flat and does not require grading. More extensive grading is required in steep side slopes, vertical areas, or wherever else necessary to avoid bending the pipeline excessively.

2.1.4 Trenching

The trench is excavated to a depth that provides sufficient cover over the pipeline after backfilling. Typically, the trench is about 4 to 6 feet wide in stable soils and about 2 to 5 feet deep to the top of the pipe, depending on the pipeline's diameter and DOT Class location. This depth allows for the required minimum of 30 to 36 inches of cover. Additional cover for the pipeline is provided at road and waterbody crossings, while less cover (a minimum of 18 inches) is required in rock. The trenching crew uses a wheel trencher or backhoe to dig the pipe trench (Figure 2.1-2).

FIGURE 2.1-1 Bulldozer Grading Pipeline ROW (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

FIGURE 2.1-2 Pipeline Trenching Operations (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

When rock or rocky formations are encountered, tractor-mounted mechanical rippers or rock trenchers are used to fracture the rock prior to excavation. In areas where mechanical equipment could not break up or loosen the bedrock, blasting is required. The contractor would be required to use explosives in accordance with state and federal guidelines to ensure a safe and controlled blast. Excavated rock would then be used to backfill the trench to the top of the existing bedrock profile.

In areas where there is a need to separate topsoil from the subsoil, the topsoil is graded prior to trenching. The topsoil over the ditch line is segregated for the majority of the project (unless requested otherwise by the landowner). Clearing activity on the spoil side is limited to what is necessary for construction activity. Topsoil is stored in a pile that is separate from the subsoil to allow for proper restoration of the soil during the backfilling process. Spoil typically is deposited on the nonworking side of the ROW, and gaps are left between the spoil piles to prevent stormwater runoff from backing up or flooding. Topsoil is returned to its original ground level plus some mounding to account for soil subsidence after the subsoil is backfilled in the trench. As backfilling operations begin, the soil is returned to the trench in reverse order, with the subsoil put back first, followed by the topsoil. This process ensures that the topsoil is returned to its original position.

2.1.5 Pipe Stringing, Bending, and Welding

Prior to or following trenching, sections of externally coated pipe up to 80 feet long (also referred to as “joints”) are transported to the ROW by truck over public road networks and along authorized private access roads and placed, or “strung,” along the trench in a continuous line.

After the pipe sections are strung along the trench and before joints are welded together, individual sections of the pipe would be bent where necessary to allow for fitting the pipeline uniformly with the varying contours of the bottom of the trench. Workers would use a track-mounted, hydraulic pipe-bending machine to shape the pipe to the contours of the terrain. The bending machine uses a series of clamps and hydraulic pressure to make a very smooth, controlled bend in the pipe (Figure 2.1-3). All bending must be performed in strict accordance with federally prescribed standards to ensure the integrity of the bend. When a section of pipe requires multiple or complex bends, that work is performed at the factory, or else pipeline fittings such as elbows are installed.

Welding is the process that joins the various sections of pipe together into one continuous length. After the pipe sections are bent, the joints are welded together into long strings and placed on temporary supports. The pipe gang and a welding crew are responsible for the welding process. The pipe gang uses special pipeline equipment called side booms to pick up each joint of pipe, align it with the previous joint, and make the first part (a pass called the stringer bead) of the weld. Additional filler passes are made by welders who immediately follow the stringer bead on what is called the welding firing line. Stringer, hot-pass, and capping welders make up the firing line, and they are followed in certain locations by tie-in welders. (On difficult-fit welds, the welder sometimes also back-welds the pipe by welding the welds from the inside to assure the integrity of the weld.) The pipe gang then moves down the line to the next section and repeats the process. The welding crew follows the pipe stringing gang to complete each weld (Figure 2.1-4).

In recent years, contractors have used semiautomatic welding units to move down a pipeline and complete the welding process. Semiautomatic welding must be completed to strict specifications and still requires qualified welders, and personnel are required to set up the equipment and hand-weld at connection points and crossings.

FIGURE 2.1-3 Pipe Bending Machine (Reproduced with permission.)

FIGURE 2.1-4 Pipeline Welding (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

As part of the quality assurance process, each welder must pass qualification tests to work on a particular pipeline job, and each weld procedure must be approved for use on that job in accordance with federally adopted welding standards. Welder qualification takes place before the project begins. Each welder must complete several welds using the same type of pipe as that to be used in the project. The welds are then evaluated by placing the welded material in a machine and measuring the force required to pull the weld apart. Interestingly, the weld has a greater tensile strength than the pipe itself. The pipe must break before the weld.

One hundred percent of the welds undergo radiographic inspection (X-ray), as outlined in 49 CFR Part 192. A second quality assurance test ensures the quality of the ongoing welding operation on-site. In this test, qualified technicians take X-rays of the pipe welds to ensure that the completed welds meet federally prescribed quality standards. The X-ray technician processes the film in a small, portable darkroom at the site. If the technician detects any flaws, the weld is repaired or cut out, and a new weld is made. Another type of weld quality inspection employs ultrasonic technology.

A protective epoxy coating or mastic is applied to the welded joints once the welds are approved. Line pipe receives an external coating, which inhibits corrosion by preventing moisture from coming into direct contact with the steel. This process is normally completed at the coating mill where the pipe is manufactured or at another coating plant location before it is delivered to the construction site. All coated pipes, however, have uncoated areas 3 to 6 inches from each end of the pipe to prevent the coating from interfering with the welding process. Once the welds are made, a coating crew coats the field joint, the area around the weld, before the pipeline is lowered into the ditch (Figure 2.1-5).

Pipeline companies use several different types of coatings for field joints, the most common being fusion-bond epoxy, polyethylene heat-shrink sleeves, or heated mastic tape. Prior to application, the coating crew thoroughly cleans the bare pipe with a power wire brush or a sandblast machine to remove any dirt, mill scale, or debris. The crew then applies the coating and allows it to dry prior to lowering the pipe in the ditch. Before the pipe is lowered into the

FIGURE 2.1-5 Crew Coating a Pipeline Field Joint (Source: TAPS 2001)

trench, the coating of the entire pipeline is inspected to ensure it is free of defects. The pipeline is then electronically inspected, or “jeeped,” for faults or voids in the epoxy coating and visually inspected for faults, scratches, or other coating defects. Damage to the coating is repaired before the pipeline is lowered into the trench.

2.1.6 Lowering-in and Backfilling

Before the pipeline is lowered into the trench, an environmental inspector inspects the trench to be sure it is free of livestock or wildlife that may have become trapped in the trench, as well as free of rocks and other debris that could damage the pipe or protective coating. At the end of the day after welding is completed, the pipe crew installs end caps (rubber expandable plugs) at the end of the pipeline to prevent debris and wildlife from entering the pipe. In areas where the trench had accumulated water since being dug, dewatering could be necessary to allow inspection of the bottom of the trench. The pipeline then is lowered into the trench. On sloped terrain, trench breakers (stacked sandbags or foam) are installed in the trench at specified intervals to prevent subsurface water movement along the pipeline.

In rocky areas, the pipeline is protected with a rock shield (a fabric or screen that is wrapped around the pipe to protect it and its coating from damage by rocks, stones, roots, and other debris) or sand aggregate. In an alternative method, the trench bottom is filled with padding material (e.g., finer grain sand, soil, or gravel) to protect the pipeline. Topsoil is not used as padding material.

Lowering the welded pipe into the trench demands the close coordination of skilled operators. By using a series of side-booms (tracked construction equipment with a boom on the side), operators simultaneously lift the pipe and carefully lower the welded sections into the trench. Nonmetallic slings protect the pipe and its coating as it is lifted and moved into position (Figure 2.1-6).

FIGURE 2.1-6 Crew Lowering a Pipeline into a Trench (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

The trench is then backfilled using the excavated material. As with previous construction crews, the backfilling crew takes care to protect the pipe and coating as the soil is returned to the trench. The soil is returned to the trench in reverse order, with the subsoil put back first, followed by the topsoil. The segregated topsoil is restored to its original grade and contour last by using either a backhoe or padding machine, depending on the soil makeup (Figure 2.1-7).

In areas where the ground is rocky and coarse, crews will either screen the backfill material to remove rocks, bring in clean fill to cover the pipe, or cover the pipe with a material to protect it from sharp rocks. Once the pipe is sufficiently covered, the coarser soil and rock can be used to complete the backfill.

2.1.7 Hydrostatic Testing

The pipeline is hydrostatically tested to ensure the system is capable of withstanding the operating pressure for which it was designed. This process involves isolating the pipe segment with test manifolds, filling the line with water, adding pressure to the section to a level commensurate with the maximum allowable operating pressure and class location, and then maintaining that pressure for a period of 8 hours. The hydrostatic test is conducted in accordance with 49 CFR Part 192.

Depending on the location of the pipeline, the water used in a hydrostatic test is drawn from a local river, stream, or lake; taken from municipal supplies; or trucked to the site. Water for hydrostatic testing generally is obtained from surface water sources through specific agreements with landowners and in accordance with federal, state, and local regulations. The pipeline is hydrostatically tested after completing the backfilling and all construction work that would directly affect the pipe. If leaks are found, the leaks are repaired and the section of pipe retested until specifications are met. Once a test section successfully passes the hydrostatic test, the water is emptied from the pipeline in accordance with state and federal requirements.

FIGURE 2.1-7 Trench Backfilling Operations (Source: TAPS 2007)

Water used for the test is then transferred to another pipe section for subsequent hydrostatic testing or analyzed to ensure compliance with the National Pollution Discharge Elimination System discharge permit requirements; if necessary, it is treated and discharged.

2.1.8 Final Tie-in

Following successful hydrostatic testing, test manifolds are removed and the final pipeline tie-ins are made and inspected.

2.1.9 Commissioning

After final tie-ins are complete and inspected, the pipeline is cleaned and dried by using mechanical tools (pigs) that are moved through the pipeline containing pressurized dry air. The pipeline is dried to minimize the potential for internal corrosion. Once the pipe has dried sufficiently, pipeline commissioning commences. Commissioning activities involve verifying that the equipment has been properly installed and is working, that controls and communications systems are functional, and that the pipeline is ready for service. In the final step, the pipeline is prepared for service by purging the line of air and loading the line with natural gas; in some cases, the gas is blended at the distribution end until achieving a certain moisture content level.

2.1.10 Cleanup and Restoration

After backfilling, final cleanup begins as soon as weather and site conditions permit. Trash and construction debris are cleaned up both during and after construction. Every reasonable effort is made to complete final cleanup (including final grading and the installation of erosion control devices) within 20 days after backfilling the trench. Construction debris is cleaned up and taken to a disposal facility, and work areas are final-graded. The crews restore the work areas to preconstruction contours, unless the landowner or land management agency directs otherwise. Appropriately spaced breaks are left in the mounded topsoil and spoil piles to prevent interference with groundwater runoff and irrigation. Segregated topsoil is spread over the surface of the ROW, and permanent erosion controls are installed.

The restoration crew carefully grades the ROW and, in hilly areas, installs erosion-prevention measures such as interceptor dikes, which are small earthen mounds constructed across the ROW to divert water. The restoration crew also installs riprap, which consists of stones or timbers, along streams and wetlands to stabilize soils.

After permanent erosion control devices are installed and final grading has been completed, all disturbed work areas are attended to as soon as possible. For instance, reseeding takes place to stabilize the soil, improve the appearance of the area disturbed by construction, and, in some cases, restore native flora. The timing of the reseeding efforts depends on weather and soil conditions and is subject to the prescribed dates and seed mixes specified by the landowner or land management agency or on the basis of other recommendations.

Access along the ROW is restricted by using gates or other barriers to minimize unauthorized entry by all-terrain vehicles. Pipeline markers are installed at fence, waterway, and road crossings to show the location of the pipeline. Markers identify the owner of the pipeline and provide emergency information. Special markers are also installed to provide information and guidance to aerial patrol pilots.

Construction crews are typically on-site for about 6 to 12 weeks, and a typical crew installs 1 mi of pipe per day. Table 2.1-1 provides a breakdown of the composition of a typical workforce during pipeline construction.

Direct emissions result from the construction of pipeline segments, although construction impacts are usually temporary and transient, and the short-term exposure levels are considered minimal. The emissions from pipeline construction are generally similar along any section of the pipeline route. These emissions include exhaust from the construction equipment and vehicle engines and fugitive dust from the disturbed areas along the ROW. Table 2.1-2 provides a

TABLE 2.1-1 Percent Breakdown of a Typical Pipeline Construction Workforce

Labor Category	Percent of Total
Pipe fitters and welders	6
Equipment operators	27
Truck drivers	29
Laborers (including welder's helpers)	18
Supervisory	6
Others (construction inspectors, camp and catering, electricians, iron workers, etc.)	13

Source: BLS (2006).

TABLE 2.1-2 Typical Emissions from the Construction of a Pipeline Segment

	Pollutant Emissions (pounds [lb]/day)				
Type of Construction Equipment	CO	HC	NO_x	SO_2	TSP
Diesel track-type tractors	233.7	81.6	849.5	32.8	30.1
Diesel wheel-type tractors	396.7	20.8	140.2	3.5	6.0
Fugitive dust from disturbed acreage	51.6	11.6	129.4	3.9	4.2
Heavy-duty diesel vehicles	7,058.0	237.2	170.8	3.3	4.3
Heavy-duty gasoline vehicles	62.6	24.7	90.4	4.2	3.4
Light-duty diesel trucks	540.4	44.8	20.1	NA[a]	0.2
Light-duty gasoline trucks	33.3	18.3	29.8	3.7	3.7
Light-duty gasoline vehicles	10.1	1.8	1.8	NA	<0.1
Miscellaneous equipment–gasoline	437.9	55.0	29.8	NA	0.1
Miscellaneous equipment–diesel	NA	NA	NA	NA	773.0
Total	8,824.3	495.8	1,461.8	51.4	825.1

[a] NA = not applicable.

Source: EPA (2000).

summary of the construction emissions inventory for the construction of a typical pipeline segment. Carbon monoxide emissions are emitted in the largest quantities during construction, followed by nitrogen oxides (NO_x), total suspended particulate (TSP), hydrocarbon (HC), and sulfur dioxide (SO_2) emissions (EPA 2000).

It is not possible to estimate the amount of water needed for pipeline hydrotesting purposes, because the volume is dependent on the location of shut-off valves and other features. The amount of water needed for pipeline hydrotesting, however, may be on the order of millions of gallons (gal) (FERC 2005b).

Typical fuels, lubricants, and hazardous materials stored or used during construction are as follows (FERC 2005b).

- Diesel and gasoline: pipeline contractor’s yard/bulk (tank trailer) containers (10,000 gal);

- Hydraulic oil and engine oil: pipeline contractor’s yard/bulk (drum) and individual (quart, gallon, and 5-gal) containers (100 gal);

- Lithium grease: pipeline contractor’s yard/bulk (5 gal) and individual (tube) containers (200 lb);

- Antifreeze: contractor's/pipeline company's yard/bulk (drum) and individual (gallon) containers (60 gal);

- Drilling mud (volume is highly site-specific).

It should be noted that the fuels and lubricants listed above are generally contained on a fuel truck that services the construction equipment along the ROW. A typical fuel truck has the storage capacity for 2,000 gal of fuel, 55 gal each of hydraulic and engine oil, 50 lb of lithium grease, and 55 gal of antifreeze mix.

Off-site pipe and equipment yards are needed during pipeline construction for the temporary storage of pipe joints, mainline valves, etc. The contractor also uses these yards to stage personnel, equipment, new pipe, and other materials necessary for construction of the facilities, and the yards could include contractor trailers, construction equipment, fuel/lubricants, and parking areas. The yards typically consist of warehouses or open lots located in areas of existing commercial or industrial use and typically range in size from 5 to 15 acres (FERC 2005a). All yards are leased from willing landowners and, upon completion of construction activities, are returned to their preconstruction condition and prior use.

2.2 SPECIAL CONSTRUCTION PROCEDURES

In addition to standard pipeline construction methods, special construction techniques are used when warranted by site-specific conditions, such as when constructing across paved roads, highways, railroads, steep terrain, waterbodies, and wetlands, and when blasting through rock. The techniques are described below.

Additional construction areas, or temporary extra workspaces, are required for construction at road crossings, railroad crossings, crossings of existing pipelines and utilities, stringing truck turnaround areas, wetland crossings, horizontal directional drilling (HDD) entrance and exit pits, and open-cut waterbody crossings. These extra workspaces are located adjacent to the construction ROW and could be used for such purposes as spoil storage, staging, equipment movement, material stockpiles, and pull-string assembly associated with HDD installation. Individual extra workspaces would range in size from less than 0.1 to 2 acres and would be returned to their preconstruction condition and former use following completion of construction activities.

2.2.1 Road, Highway, and Railroad Crossings

Construction across paved roads, highways, and railroads would be carried out in accordance with the requirements of the appropriate road and railroad crossing permits and approvals obtained by the pipeline company. In general, major paved roads, highways, and railroads are crossed by boring beneath the road or railroad. Boring requires excavating a pit on each side of the feature, placing the boring equipment in the pit, and then boring a hole under the road at least equal to the diameter of the pipe. Once the hole is bored, a prefabricated pipe section is pushed through the borehole that would consist of either extra-heavy wall-thickness carrier pipe or two pipes consisting of an outer casing pipe and the inner carrier pipe. For long crossings, sections could be welded onto the pipe string just before being pushed through the borehole. Boring activities would result in minimal or no disruption to traffic at road, highway, or railroad crossings. Each boring project is expected to take 2 to 10 days. Operations typically are conducted 24 hours per day, 7 days per week until the boring is completed.

Most smaller unpaved roads and driveways are crossed using the open-cut method where permitted by local authorities or private owners. The open-cut method requires temporarily closing the road to traffic and establishing detours. In instances where a reasonable detour is not feasible, at least one lane of traffic is kept open except during brief periods when it is essential to close the road to install the pipeline. Most open-cut road-crossing construction projects (including road resurfacing) take some weeks to complete, depending on soil settlement after compaction. (In general, most pipeline companies prefer to wait several weeks before final resurfacing.) Posting signs at open-cut road crossings and other measures are undertaken to help ensure safety and minimize traffic disruptions.

2.2.2 Steep Terrain

Additional grading may be required in areas where the proposed pipeline route crosses steep slopes. Steep slopes often need to be graded down to a gentler slope to accommodate pipe-bending limitations. In such areas, the slopes are cut away and, after the pipeline is installed, reconstructed to their original contours during restoration.

In areas where the proposed pipeline route crosses laterally along the side of a slope, cut-and-fill grading may be required to obtain a safe, flat, work terrace. Generally, on steep side slopes, soil from the high side of the ROW is excavated and moved to the low side of the ROW to create a safe and level work terrace. Under these circumstances, the topsoil is stripped from the entire width of the ROW. After the pipeline is installed, the soil from the low side of the ROW is returned to the high side, the topsoil is replaced, and the slope’s original contours are restored.

In steep terrain, temporary sediment barriers such as silt fences and certified weed-free straw bales are installed during clearing to prevent the movement of disturbed soil off the ROW. Temporary slope breakers that consist of mounded and compacted soil are installed across the ROW during grading, and permanent slope breakers are installed during cleanup. Following construction, seed is applied to steep slopes, and the ROW is mulched with certified weed-free hay or nonbrittle straw or is covered with erosion-control fabric. Sediment barriers are maintained across the ROW until permanent vegetation is established.

2.2.3 Waterbody Crossings

The generally preferred method of crossing a waterbody that is flowing at the time of construction is HDD compared to the open-cut method, since HDD’s decreasing cost and lack of environmental impact are making it more popular. The open-cut crossing method involves trenching through the waterbody while water continues to flow through the trenching area. If no water is flowing at the time of construction, the waterbody is crossed using conventional upland cross-country construction techniques.

The open-cut crossing method involves excavating a trench across the bottom of the river or stream to be crossed with the pipeline. Depending on the depth of the water, the construction equipment may have to be placed on barges or other floating platforms to complete excavation of the pipe trench. If the water is shallow enough, the contractor can divert the water flow with dams and flume pipe, which can allow backhoes working from the banks or the streambed to dig the trench.

The contractor prepares the pipe for the crossing by stringing it out on one side of the stream or river and then welding, coating, and hydrostatically testing the entire pipe segment. Sidebooms carry the pipe segment into the stream bed just as they do for construction on land, or the construction crew floats the pipe into the river with flotation devices and positions it for being buried in the trench. Concrete weights or concrete coating ensure that the pipe will stay in position at the bottom of the trench once the contractor removes the flotation devices (Figure 2.2-1).

The flume, dam-and-pump, and HDD methods also could be considered as alternative crossing methods. The flume crossing method involves diverting the flow of water across the trenching area through one or more flume pipes placed in the waterbody. The dam-and-pump method is similar to the flume method except that pumps and hoses are used instead of flumes to move water around the construction work area (Figure 2.2-2).

The HDD method involves drilling a hole under the waterbody and installing a prefabricated segment of pipe through the hole. Before a directional drill is designed, core samples are taken on both sides of the crossing to evaluate the underground rock and sand formations. If the subsurface will support a directional drill, the engineer can design a crossing that establishes the entry and exit points of the pipeline crossing and its profile as it would traverse under the crossing.

The HDD method involves drilling a pilot hole under the waterbody and banks and then enlarging the hole through successive reamings until the hole is large enough to accommodate a prefabricated segment of pipe. Throughout the process of drilling and enlarging the hole, a slurry made of nontoxic fluids (e.g., bentonite and water) is circulated through the drilling tools to lubricate the drill bit, remove drill cuttings, and keep the hole open. This slurry is referred to as drilling mud.

While this drilling is in progress, the line pipe sections are strung out on the far side of the crossing for welding. Once welded, the joints are X-rayed, coated, hydrostatically tested, and then placed on rollers or padded skids in preparation for being pulled through the drilled-out hole.

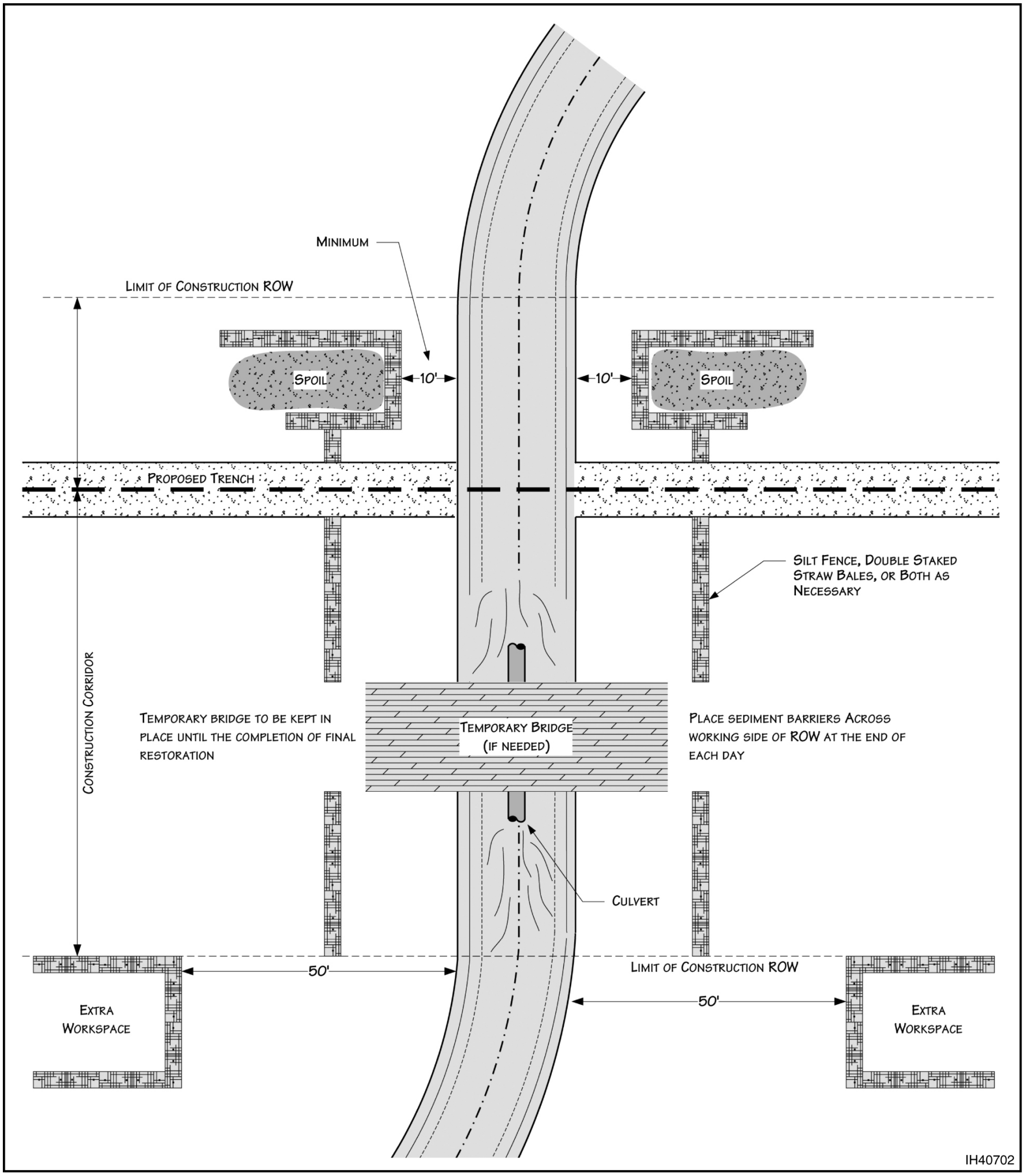


FIGURE 2.2-1 Typical Open-Cut Waterbody Crossing Method (Source: FERC 2006a)

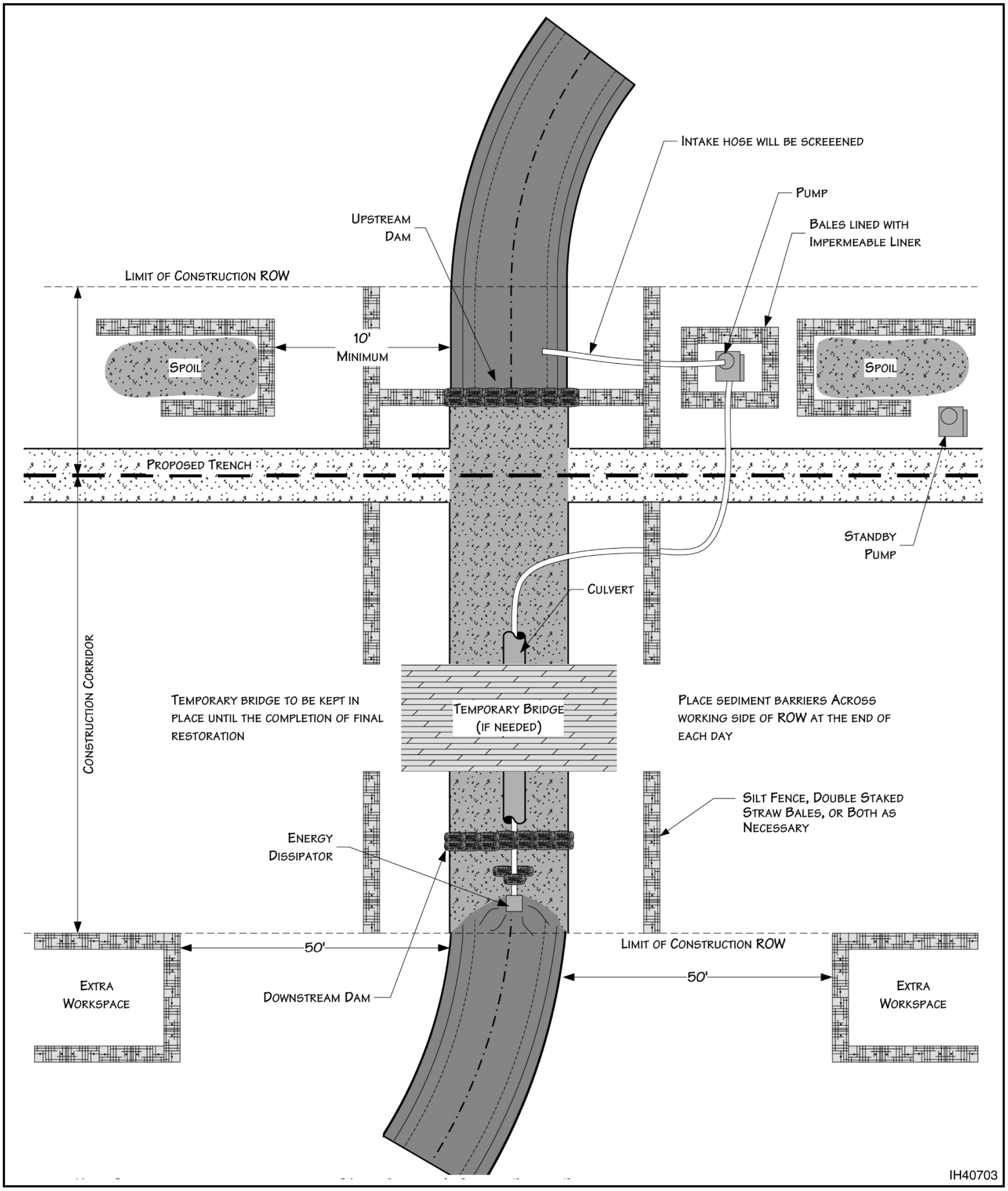


FIGURE 2.2-2 Typical Dam-and-Pump Waterbody Crossing Method (Source: FERC 2006a)

Once the drilling operation is complete, the cutting head is removed and the drill string is attached to the welded pipeline segment. The crew uses the drilling rig, winches, or dozers to pull the pipeline segment through the drilled hole, where it is then connected into the pipeline on both ends. Once the hole is bored, a prefabricated pipe section is pushed through the borehole that consists of either extra-heavy wall-thickness carrier pipe or two pipes consisting of an outer casing pipe and the inner carrier pipe.

Ideally, there are no impacts on the banks, bed, or water quality of the waterbody being crossed by using the HDD method. Figure 2.2-3 shows an HDD waterbody crossing in process, and Figure 2.2-4 shows a conceptual plan for an HDD crossing.

FIGURE 2.2-3 Horizontal Directional Drilling (HDD) Operation (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

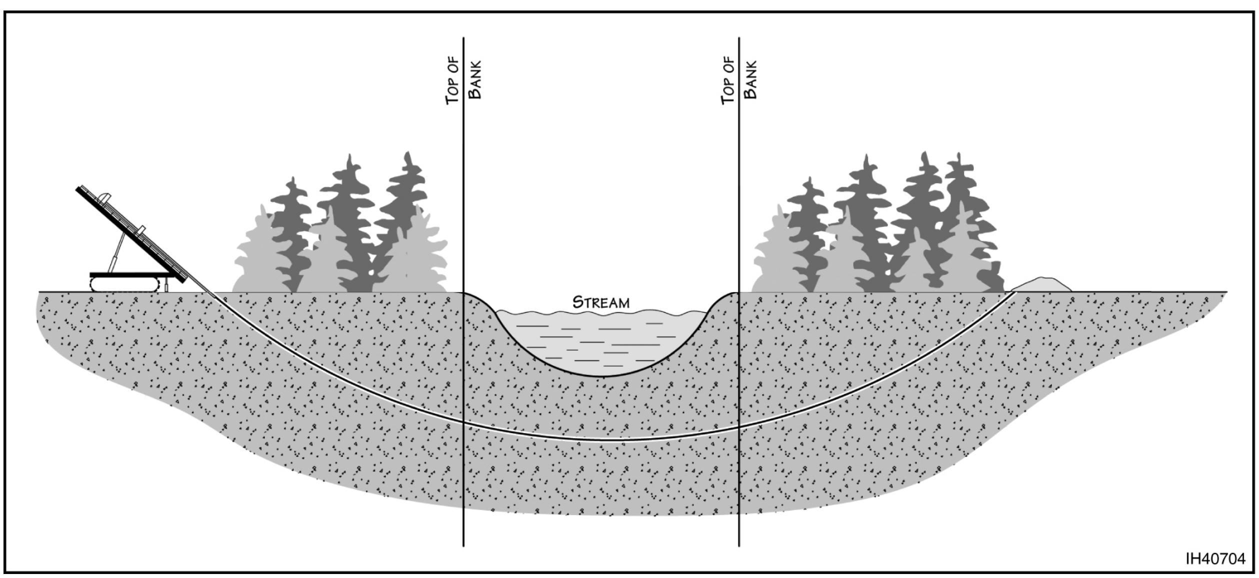


FIGURE 2.2-4 Typical HDD Waterbody Crossing Method (Source: FERC 2006a)

Regardless of which crossing method is used, additional temporary workspace areas are required on both sides of all waterbodies to stage construction, fabricate the pipeline, and store materials. For most crossings, these workspaces are located at least 50 feet away from the water's edge, except where the adjacent upland consists of actively cultivated or rotated cropland or other disturbed land.

Before construction, temporary bridges (e.g., clean rock fill over culverts, timber mats supported by flumes, railcar flatbeds, flexi-float apparatus) are installed across all perennial waterbodies to allow construction equipment to cross. Construction equipment must cross by using the bridges, with the exception of the clearing crew, which is allowed one pass through the waterbodies before the bridges are installed.

2.2.4 Wetland Crossings

Pipeline construction across wetlands is similar to typical conventional upland cross-country construction procedures, with several modifications and limitations to reduce the potential for pipeline construction to affect wetland hydrology and soil structure. Another option is to employ HDD methods for crossing the wetlands (as discussed in previous paragraphs). In one technique, crews place large timber mats ahead of the construction equipment to provide a stable working platform. The timber mats act much like snowshoes, spreading the weight of the construction equipment over a broad area. The mats make it possible to operate the heavy equipment on the unstable soils.

Typically, a 75-foot-wide construction ROW is maintained through wetlands. Additional temporary workspace areas are required on both sides of wetlands to stage construction, fabricate the pipeline, and store materials. These additional temporary workspace areas are located in upland areas a minimum of 50 feet from the wetland edge (Figure 2.2-5).

Construction equipment used while working in wetlands are limited to only those pieces of equipment that are essential for clearing the ROW, excavating the trench, fabricating and installing the pipeline, backfilling the trench, and restoring the ROW. In areas where there is no reasonable access to the ROW except through wetlands, nonessential equipment is allowed to travel through wetlands only if the ground is firm enough or has been stabilized to avoid rutting. Otherwise, nonessential equipment is allowed to travel through wetlands only once.

Vegetation clearing in wetlands is limited to trees and shrubs, which are cut flush with the surface of the ground and removed from the wetland area. Stump removal, grading, topsoil segregation, and excavation are limited to the area immediately above the trenchline to avoid excessive disruption to wetland soils and the native seed and root stock within the wetland soils. A limited amount of stump removal and grading could be conducted in other areas where there may be safety-related concerns.

During clearing, sediment barriers such as silt fences and staked, certified weed-free straw bales are installed and maintained adjacent to wetlands and within additional temporary workspace areas as necessary to minimize the potential for sediment runoff. Sediment barriers

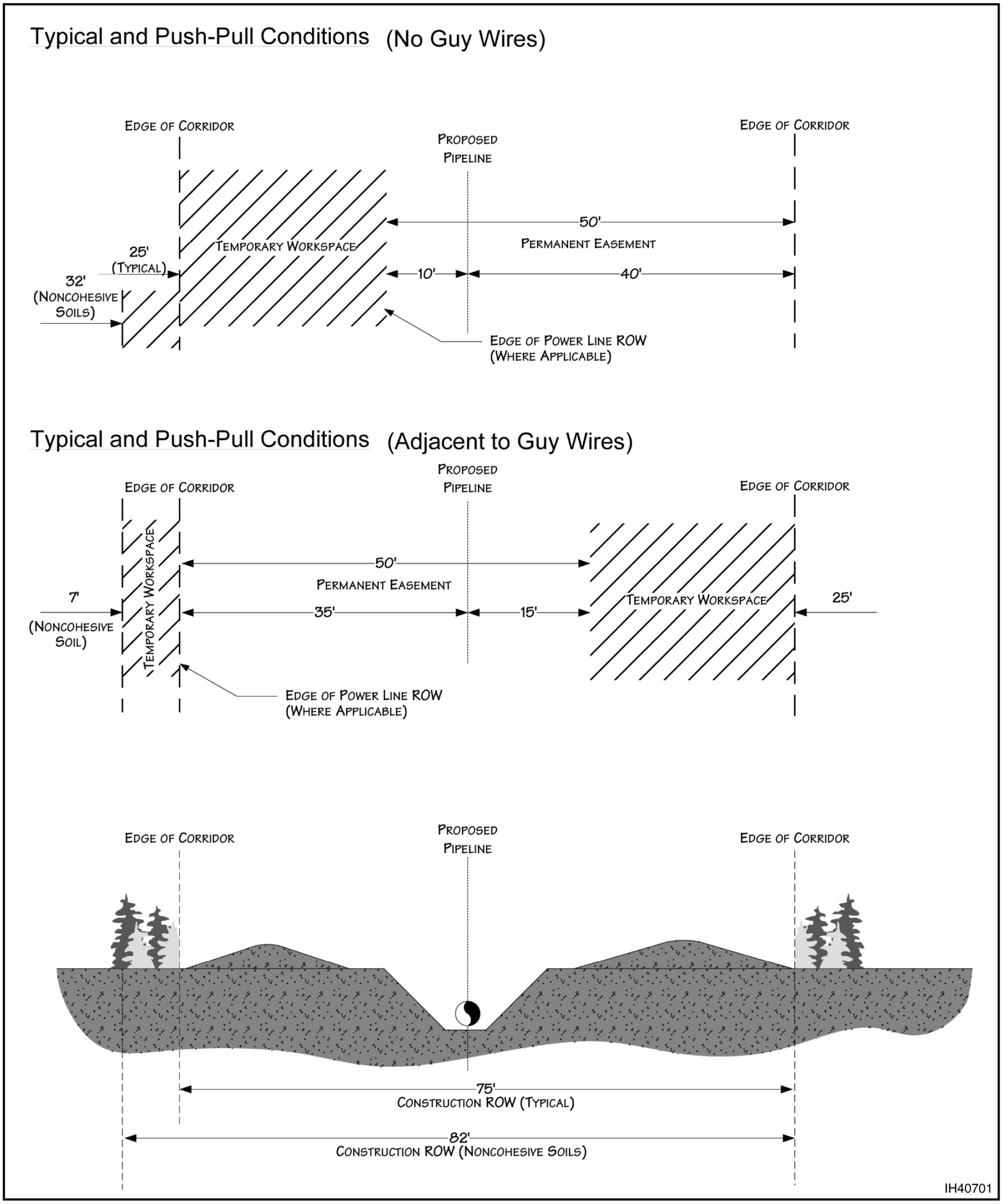


FIGURE 2.2-5 Typical Pipeline ROW in Wetlands (Source: FERC 2006a)

also are installed across the full width of the construction ROW at the base of slopes adjacent to wetland boundaries. The silt fence and/or certified weed-free straw bales installed across the working side of the ROW are removed during the day when vehicle traffic is present and replaced each night. Alternatively, drivable berms can be installed and maintained across the ROW in lieu of the silt fence or certified weed-free straw bales. Sediment barriers also are installed within wetlands along the edge of the ROW where necessary to minimize the potential for sediment to run off the construction ROW and into wetland areas located outside the work area.

The method of pipeline construction used in wetlands depends largely on the stability of the soils at the time of construction. For instance, if wetland soils are not excessively saturated at the time of construction and can support construction equipment on equipment mats, timber riprap, or certified weed-free straw mats, then construction occurs in a manner similar to conventional upland cross-country construction techniques. In unsaturated wetlands, topsoil from the trenchline is stripped and stored separately from the subsoil. Topsoil segregation generally is not possible in saturated soils.

Where wetland soils are saturated and/or inundated, the pipeline can be installed using the push-pull technique, which involves stringing and welding the pipeline outside of the wetland area and excavating and backfilling the trench using a backhoe supported by equipment mats or timber riprap. The prefabricated pipeline is installed in the wetland area by equipping it with buoys and pushing or pulling it across the water-filled trench. After the pipeline is floated into place, the floats are removed and the pipeline sinks into place. Most pipe installed in saturated wetlands is coated with concrete or equipped with set-on weights to provide negative buoyancy (Figure 2.2-6).

Because there is little or no grading when constructing in wetlands, restoration of contours is accomplished during backfilling. Prior to backfilling, trench breakers are installed

FIGURE 2.2-6 Pipeline for Wetland Installation Encased in Concrete to Counteract Positive Buoyancy (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

where necessary to prevent the subsurface drainage of water from wetlands. In areas where topsoil has been segregated from subsoil, the subsoil is backfilled first, followed by the topsoil. Topsoil is replaced to the original ground level, leaving no crown over the trenchline. In some areas where wetlands overlie rocky soils, the pipe is padded with rock-free soil or sand before backfilling with native bedrock and soil. Equipment mats, timber riprap, gravel fill, geotextile fabric, and/or certified weed-free straw mats are removed from wetlands following backfilling.

In areas where wetlands are located at the base of slopes, permanent slope breakers are constructed across the ROW in upland areas adjacent to the wetland boundary. Temporary sediment barriers are installed where necessary until revegetation of adjacent upland areas is successful. Once revegetation is successful, sediment barriers are removed from the ROW and disposed of properly. In wetlands where no standing water is present, the construction ROW is seeded in accordance with the recommendations of the local soil conservation authorities. Lime, mulch, and fertilizer are not used in wetlands.

2.2.5 Blasting

Strict safety precautions are followed if blasting is required to clear the ROW and fracture the ditch. Extreme care is exercised to avoid damage to underground structures, cables, conduits, pipelines, and underground watercourses or springs. Adjacent landowners or tenants are provided adequate notice in advance of blasting so they can protect their property and livestock. Blasting activity is performed during daylight hours and in compliance with federal, state, and local codes and ordinances and manufacturers' prescribed safety procedures and industry practices. Blasting does not typically occur in streams except in areas where hard rock is encountered and HDD is not economical. After blasting, the remnants typically are removed by backhoes or similar construction equipment.

2.2.6 Fences and Grazing

Grazing permittees are contacted prior to the start of construction and reclamation on their allotments. If gaps in natural barriers used for livestock control are created by the pipeline construction, the gaps are fenced according to the landowner's or land management agency's requirements. Any openings in the fenceline are temporarily closed when construction crews leave the area, to prevent livestock from passing through the construction area. In addition, a minimum of 10 feet of undisturbed area is maintained whenever possible in areas where the pipeline runs parallel to a fenceline. All existing improvements, such as fences, gates, irrigation ditches, cattle guards, and reservoirs, are maintained during construction and repaired to preconstruction conditions or better.

2.2.7 Rugged Topography

It is possible that some portions of a proposed pipeline route would traverse areas containing side slopes and rolling terrain that could require the "two-tone" construction technique to provide for safe working conditions. In the two-tone construction technique, the uphill side of the construction ROW is cut during grading. The material removed from the cut is used to fill the downhill side of the construction ROW to provide a safe and level surface from which to operate heavy equipment. The pipeline trench is then excavated along the newly graded ROW. Figure 2.2-7 provides a typical cross section of the two-tone construction technique.

The two-tone construction technique usually requires extra workspace areas to accommodate the additional volumes of fill material generated by using this technique.

Following pipeline installation and backfill of the trench, excavated material is placed back in the cut and compacted to restore the approximate original contours. All disturbed areas are then stabilized.

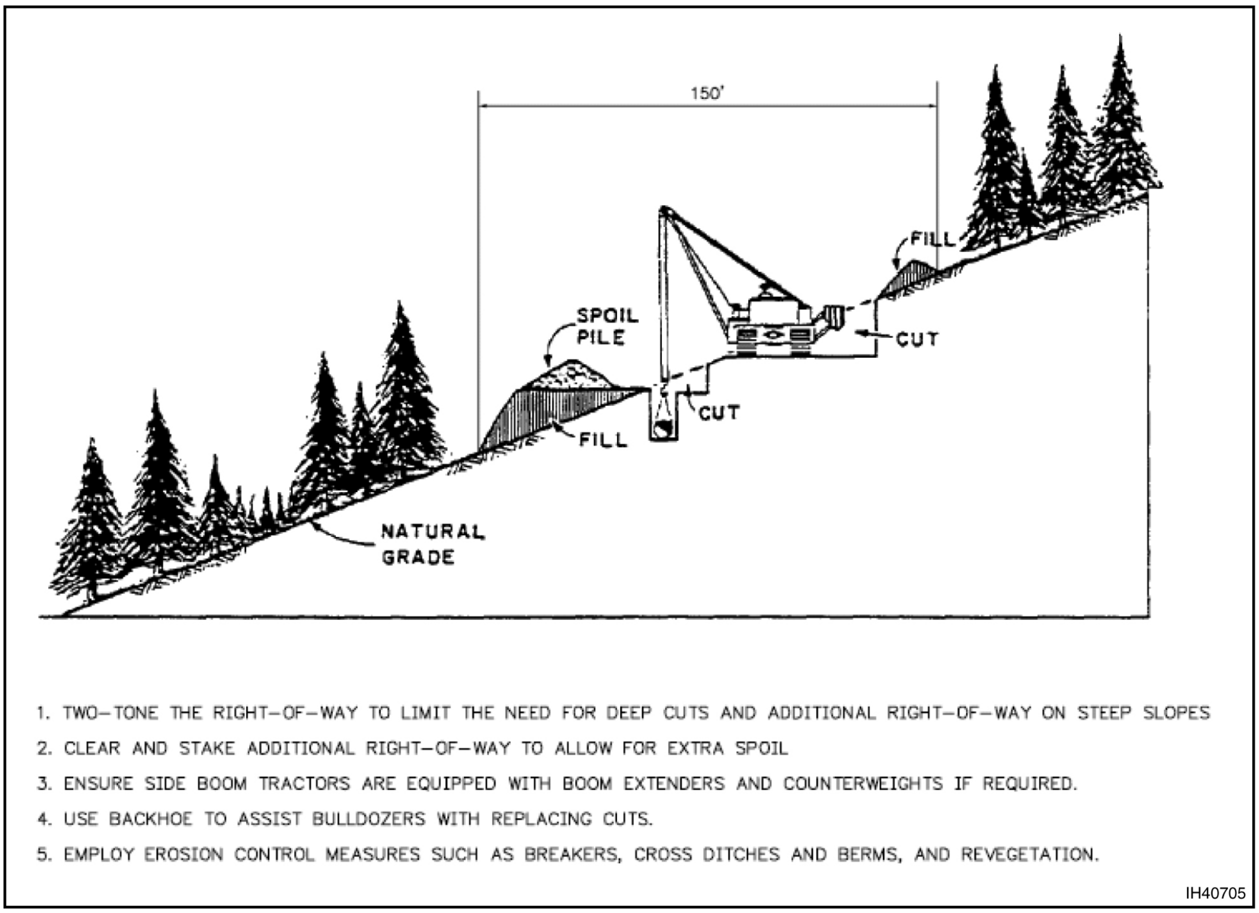


FIGURE 2.2-7 Typical Two-Tone Construction ROW (Source: FERC 2006b)

2.2.8 Construction Immediately Adjacent to Other Pipelines

The company that owns the existing pipeline must be notified according to state law before construction begins in the vicinity of its facilities. This notification shall be made through the appropriate state's One-Call notification service, but follow-up contact must be made to the existing pipeline's company to seek approval for the proposed construction. Workers must use hand tools to dig approved excavations above, below, or within 3 feet of either side of the pipeline.

No construction or excavation activities of any kind, including blasting, shall be carried out on an existing pipeline's ROW before its personnel have established the actual locations of all affected facilities and the limits of the ROW. Personnel from the existing pipeline company would be present during any construction or excavation activities.

The existing pipeline's owner may require heavy-equipment operators to install mats, dirt pads, or other approved protective materials to adequately protect its pipeline from potential damage by heavy equipment crossing the ROW. The existing pipeline's personnel would evaluate all proposed road crossings of buried facilities. Any additional overburden would be removed after construction unless directed otherwise by the existing pipeline's owner.

Figure 2.2-8 illustrates one potential construction ROW where the proposed pipeline is located parallel to an existing pipeline (FERC 2005a).

Any blasting proposed within 300 feet of existing pipeline facilities is submitted to the attention of the existing pipeline's owner in advance, along with a blasting plan outlining the proposed activity. No blasting can begin until the existing pipeline's owner provides written confirmation that it does not object to such blasting. Any modifications to the blasting plan are also submitted to the existing pipeline's owner for review and are not implemented unless the owner provides written confirmation that it does not object to such modifications. The blasting contractor may be required to monitor and record seismic shock at the existing facilities.

Any directional drilling or boring proposed under an existing pipeline's buried facilities must be submitted to the existing pipeline company for review and approval. Adequate clearance must be maintained from the existing facilities, and additional excavations may be required to ensure adequate clearance. As-built plans are required for all borings.

The existing pipeline company must be notified of any construction or excavation proposed to occur within 300 feet in any direction of a natural gas storage well. For safety, the existing pipeline company reserves the right to object to any such proposed activities or the placement of objects closer than 300 feet to a storage wellhead.

Any proposed pipeline is constructed 40 feet from the existing pipelines wherever possible. In locations where this is not feasible, the new pipeline is located within 20 feet or less of one or both of the existing pipelines, generally between the two existing pipelines. The pipeline company must contact the operator of the existing pipeline to restrict flows or reduce pressure in the existing pipeline during construction periods to allow heavy equipment to work

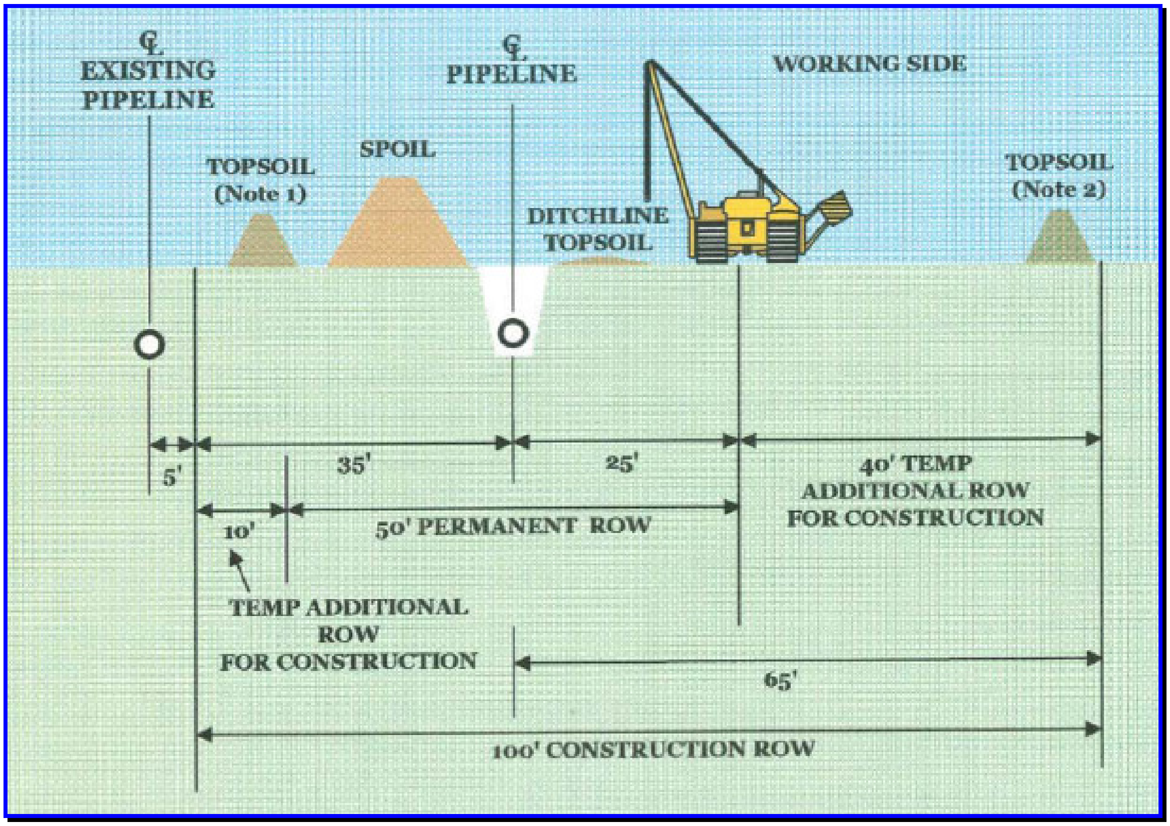


FIGURE 2.2-8 Typical Construction ROW When Adjacent to Existing Pipeline (FERC 2005a)

over the existing line. Spoil from the ditch is cast away from the existing pipeline, and no equipment will move back and forth over that particular pipeline. Once construction is completed, flows and/or pressures in the existing pipeline can resume at normal levels.

2.3 ABOVEGROUND FACILITY CONSTRUCTION PROCEDURES

The aboveground facilities are constructed concurrent with pipeline installation, but construction is conducted by special fabrication crews that generally work separately from the pipeline construction spreads.

2.3.1 Compressor Stations

Construction of the compressor stations involves clearing, grading, and compacting the sites to the surveyed elevations where necessary for placement of concrete foundations for buildings and to support skid-mounted equipment. Prefabricated segments of pipe, valves, fittings, and flanges are welded at the shop or on-site and assembled at the compressor station site. The compressor units and other large equipment are mounted on their respective foundations, and the equipment is micro-leveled to reduce vibration; then the compressor enclosures are erected around them. Noise-abatement equipment (including sound-attenuating enclosures around the turbines, exhaust stack silencers, and air inlet silencers) and emission control technology are installed as needed to meet applicable federal, state, and/or local standards. Electrical, domestic water and septic, and communications utilities are installed as necessary.

Facility piping, both above and below ground, are installed and hydrostatically tested before being placed into service. Controls and safety devices such as the emergency shutdown system, relief valves, gas and fire detection facilities, and other protection and safety devices are also checked and tested. Upon completion of construction, all disturbed areas associated with the aboveground facilities are finish-graded and seeded or covered with gravel, as appropriate. All roads and parking areas are graveled. Additionally, the compressor station sites are fenced for security and protection.

Somewhat less than 100 workers and five inspectors are required to construct a typical compressor station. Initial site preparation typically takes approximately 16 to 20 weeks, while actual installation requires more than 6 months. The lead time needed to purchase some equipment, such as compressors, is more than 1 year.

Direct emissions would result from the construction of a natural gas compressor station, although construction impacts are expected to be temporary and transient, and the short-term exposure levels are considered minimal. These emissions include exhaust from the construction equipment and vehicle engines and fugitive dust from the disturbed areas along the ROW. Table 2.3-1 provides a summary of the emissions inventory for the construction of a typical compressor station. Carbon monoxide emissions are emitted in the largest quantities during construction, followed by TSP, NO_x, HC, and SO_2 emissions.

TABLE 2.3-1 Typical Emissions from the Construction of a Natural Gas Compressor Station

	Pollutant Emissions (lb/day)				
Type of Construction Equipment	CO	HC	NO_x	SO_2	TSP
Track-type diesel tractors	23.5	8.2	85.7	3.3	3.0
Wheel-type diesel tractors	30.5	1.6	10.8	0.3	0.5
Misc. equipment–gasoline	556.6	18.2	13.5	0.3	0.3
Heavy-duty diesel vehicles	4.7	1.9	6.8	0.3	0.3
Light-duty gasoline trucks	16.8	2.1	1.2	NA	<0.1
Fugitive dust from disturbed acreage	NA[a]	NA	NA	NA	155.6
Total	632.1	32.0	118.0	4.2	159.8

[a] NA = not applicable.

Relatively small amounts of water (on the order of 300,000 gal) are needed to meet the hydrotesting requirements of the compressor station and associated piping (FERC 2005b).

2.3.2 Meter Stations, Valves, and Pig Launcher/Receiver Facilities

Construction of meter and regulator stations, mainline valves, and pig launcher/receiver facilities that are not colocated with the compressor stations are generally similar to that described above for compressor station sites, and entail site clearing and grading, installation and erection of facilities, hydrostatic pressure testing, cleanup and stabilization, and installation of security fencing around the facilities. However, construction is usually completed in 1 to 3 months.

Mainline valve sites consist of a 40-foot by 40-foot fenced area installed within the confines of the permanent pipeline ROW. Thus, construction and operation of those facilities do not require additional land beyond that already noted for the permanent pipeline ROW.

Relatively small amounts of water (on the order of 100,000 gal) are needed to meet the hydrotesting requirements of the meter station and associated piping (FERC 2005b). On small sections of pipe, air or nitrogen may be used for hydrotesting purposes.

2.3.3 Telecommunications Towers

Tower construction involves erecting a 40-foot-tall, three-leg communications tower with associated microwave parabolic dish antennas, as well as a self-contained 11-foot by 21-foot by 9-foot-tall concrete communications building on a simple slab foundation within a 40-foot by 60-foot (0.06-acre) area. A propane tank is typically installed on the site to supply fuel to a backup emergency generator located inside the building. The 40-foot by 60-foot area is graveled and fenced.

2.3.4 Corrosion Protection and Detection Systems

Corrosion in pipelines is a common phenomenon, and must be controlled effectively to prevent pipeline leaks or structural problems. Although modern pipes are constructed of high-quality steel, this material will nevertheless corrode over time. Corrosion occurs when an electrical current flows naturally from a pipe into the surrounding soil, causing metal loss, or corrosion.

One way to impede this process is to insulate the metal from the soil, which occurs when the pipe is coated in the manufacturing process. The coating is rechecked at the construction site using a detector that looks for imperfections or gouges that could occur during transportation. A new coating is then applied at the welded joints between pipe sections by sandblasting the weld and then applying the new coat.

A cathodic protection system would be installed to protect all underground and submerged pipeline facilities that are constructed of metallic materials from external, internal, and atmospheric corrosion.

Rectifiers and anode “ground beds” are installed at strategic points along the pipeline to further protect the pipeline from corrosion. Ground beds provide cathodic protection by inducing a very small electrical current into the soil, impeding the flow of electrons to the pipe. The rectifier that induces the current into the ground bed is checked regularly by pipeline personnel, who ensure that the system is applying sufficient current to maintain cathodic protection to the pipeline. A single 200-foot ground bed can protect as much as 50 miles of pipeline, but the low voltages used do not harm animals or plants in the vicinity. Bonding occurs between separated pipelines and companies within a common ROW (the current for all pipelines operates at the same level).

3 PIPELINE OPERATION AND MAINTENANCE

Once the natural gas pipeline is in service, the pipeline's control center electronically monitors the operations 24 hours a day, 365 days a year. A computerized gas monitoring system is used to read pressures along the pipeline on a continuous basis.

The compressor stations emit air pollutants as a result of the combustion of natural gas that drives the compressor units and the periodic operation of an auxiliary generator. Table 3-1 summarizes the anticipated emissions of NO_x, carbon monoxide (CO), volatile organic carbon (VOC), particulate matter less than 10 micrometers in diameter (PM_{10}), SO_2, and hazardous air pollutants (HAPs). Compressor station emissions are minimized by using the best available control technology and clean-burning natural gas fuels. The compressor stations are operated in compliance with federal and state air quality regulations driven by the Clean Air Act. It may be expected that any compressor stations would not be subject to prevention of significant deterioration (PSD) permitting requirements because the net emissions from each compressor station would not meet the PSD applicability thresholds.

The compressor stations include an emergency shutdown (ESD) system pursuant to DOT safety requirements. Activation of the ESD system in the event of an emergency vents the piping (expels the natural gas) to the atmosphere. The ESD system is tested at initial commissioning of the station, and property owners in the area are notified of the test. After the initial test, the ESD system would be used only in the event of an emergency. Additionally, each compressor unit and mainline valve facility typically include a blowdown valve that is used during maintenance activities (e.g., to relieve pressure when a unit is taken off-line). Natural gas blowdowns are not

TABLE 3-1 Typical Pollutant Emissions from Natural Gas Compressor Station Operations

Pollutant	Facility Emissions (tons per year [tpy])[a]	Applicability Threshold (tpy)[b]
NO_x	<100	250
CO	<100	250
VOC	<10	250
PM_{10}	<10	250
SO_2	<10	250
HAPs	<1	25

[a] Includes emissions from turbines, auxiliary generators, tanks, fugitive emissions, and loading.

[b] Prevention of Significant Deterioration New Source Applicability Threshold.

Source: Argonne estimate (2006).

part of routine operation and are considered an insignificant emission source because of the minimal amount of VOC contained in the vented natural gas.

Operation of natural gas ancillary facilities does not result in substantial air emissions under normal operating conditions. Typically, only minor fugitive emissions of natural gas occur from small connections at meter station and valve sites. Because such emissions are very small and discountable, they are not regulated by permit or source-specific requirements.

Unlike most technologies, the pollution output from pipeline operations focuses on pipeline ruptures. By definition, most pollution outputs associated with pipeline operations are the natural gas resources and products that the pipelines convey.

Potentially hazardous wastes generated during pipeline operations include pipeline sludge, spent pigs, sandblast abrasive (depending on type and use), methyl ethyl ketone, paint thinner, and solvents. Common wastes include oily rock/soil, oily rags, sandblast abrasive (depending on type and use), and general trash/garbage (FERC 2005b). The typical amounts of waste generation would be small, and any wastes generated would be stored using DOT-approved containers, a frac tank (for bulk liquid wastes), and a covered steel roll-off container with a poly liner (for bulk solid wastes like contaminated soil) or on a thick poly liner; an area would be provided with a poly-liner cover and temporary containment berm (for bulk solid wastes).

Large amounts of debris can be removed by a pig run over a long distance. For example, if a pig is run in a 24-inch-diameter pipeline that is 100 miles long and removes 0.016 inch of wax material from the wall of the pipeline, the pig would be pushing a plug of wax about 1,450 feet long after traveling 100 miles. The cleaning process may require several sweeps by the pig to clean the line effectively. Both brush and scraper pigs contain holes that allow fluid to bypass the pig, preventing buildups in front of the machine that could cause plugging.

Natural gas is produced and used continuously throughout each day. As a result, split, weekend, and night shifts are common for natural gas workers. The average workweek for production workers was 40.9 hours in 2004, compared with 33.5 hours for all trade, transportation, and utilities industries, and 33.7 hours for all private industries (BLS 2006).

Employees often must work overtime to accommodate peaks in demand and to repair damage caused by storms, cold weather, accidents, and other occurrences. The industry employs relatively few part-time workers.

3.1 ROW MONITORING AND MAINTENANCE

Leak detection methods may be divided into two categories: direct and inferential. Direct methods detect leaking commodity outside the pipeline. Inferential methods deduce a leak by measuring and comparing the amount of product moving through various points on a line.

Traditionally, pipelines have been inspected visually by walking along the line or patrolling the pipeline route from the air. Section 195.705 of the federal pipeline safety regulation 49 CFR Part 195, “Transportation of Hazardous Liquids by Pipeline” (GPO 2007), requires that hazardous natural gas pipelines be patrolled to observe surface conditions on and adjacent to the transmission line ROW for indications of leaks, construction activity, and other factors affecting safety and operation.. The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, as shown in Table 3.1-1.

During operations, the pipeline company conducts regular patrols of the pipeline ROW in accordance with the requirements of 49 CFR Part 192. The patrol program would include periodic aerial and vehicle patrols of the pipeline facilities. These patrols are conducted to survey surface conditions on and adjacent to the pipeline ROW for evidence of leaks, unauthorized excavation activities, erosion and washout areas, areas of sparse vegetation, damage to permanent erosion control devices, exposed pipe, and other conditions that might affect the safety or operation of the pipeline.

The cathodic protection system is also inspected periodically to ensure that it is functioning properly. In addition, “smart” pigs are regularly sent through the pipeline to check for corrosion and irregularities in the pipe. Developed from earlier technology (mechanical pigs used for cleaning), smart pigs carry detection and logging tools that store data on the state of the pipeline, including data on metal loss, pits, gouges, and dents, while moving through the pipeline system. The smart pig is launched from a pig launcher (a spur off the mainline), run through the pipeline segment, trapped, and removed from the pipeline. The data is then downloaded from the smart pig data storage unit and analyzed. The pipeline company keeps detailed records of all inspections and supplements the corrosion protection system as necessary to meet the requirements of 49 CFR Part 192.

TABLE 3.1-1 Patrol Frequency for Natural Gas Transmission Pipelines

	Maximum Interval between Patrols	
Characteristics of Area Consisting of 220 yards of 1-mile Length of Pipeline	At Highway and Railroad Crossings	At All Other Places
Any location having fewer than 46 buildings intended for human occupancy	7.5 months; but at least twice each calendar year.	15 months; but at least once each calendar year.
Any location having 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of a building	4.5 months; but at least four times each calendar year.	7.5 months; but at least twice each calendar year.
Any location where buildings with four or more stories above ground are prevalent	4.5 months; but at least four times each calendar year.	4.5 months; but at least four times each calendar year.

Routine operation and maintenance are also performed at all aboveground facilities by qualified personnel. Safety equipment, such as pressure-relief devices, fire detection and suppression systems, and gas detection systems, are maintained throughout the life of each facility. Mainline valves are also inspected, serviced, and tested to ensure proper functioning.

Vegetation management procedures during operation are performed in accordance with the pipeline's plan and procedures and include regular mowing, cutting, and trimming along most of the permanent pipeline ROW. Routine vegetative maintenance clearing would not be performed more frequently than every 3 years, unless requested and/or approved by appropriate state and local agencies. However, a corridor that does not exceed 10 feet in width centered on the pipeline could be maintained annually in a herbaceous state as required to facilitate periodic corrosion and leak detection surveys.

In addition, routine vegetation maintenance may not occur between April 15 and August 1 of any year, to minimize the potential for impacts on migratory bird species that may use the permanent ROW for nesting.

3.2 PIPELINE INTEGRITY

In December 2002, President George W. Bush signed into law the Pipeline Safety Bill H.R. 3609, the Pipeline Safety Improvement Act of 2002. One of the provisions of the act requires the Secretary of Transportation to issue regulations that define integrity management programs prescribing the standards for conducting a risk analysis and for adoption and implementation of an integrity management program for natural gas pipelines.

In December 2003, the DOT Office of Pipeline Safety issued a final rule requiring natural gas pipeline operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm; that is, where it could impact high-consequence areas.

The program — mandated by DOT's Office of Pipeline Safety and part of federally mandated rules designed to improve the safety of natural gas distribution and transmission systems — consists of five elements:

- *Integrity Management Plan (IMP)*. Processes and procedures that are followed to ensure compliance with the Gas Integrity Management Rule. The plan establishes procedures for identifying high-consequence areas; gathering, reviewing, and integrating data; performing risk and integrity assessments; applying prevention, mitigation, and remediation measures; and assigning reassessment intervals for continually evaluating the integrity of covered segments.

- *Performance Plan*. Processes and procedures used to measure the effectiveness of the IMP per the requirements of the Gas Integrity Management Rule and criteria set forth by the natural gas pipeline company.

- *Communications Plan*. Processes and procedures for communicating Performance Plan results and other information pertinent to the IMP.

- *Management of Change Plan*. Identifies and considers the impact of technical, physical, procedural, and organizational changes to the natural gas transmission pipeline systems and their integrity.

- *Quality Management Plan*. Processes and procedures established to ensure that the requirements of the IMP are being met, documented, and continually improved.

3.3 FUTURE PLANS AND ABANDONMENT

A natural gas pipeline generally has a design life of more than 50 years, although the actual life may be considerably longer. However, in the event of project termination/ abandonment, the aboveground structures are typically removed, while subsurface structures are abandoned in place.

The FERC typically allows a buried pipeline that has reached the end of its service life to be internally cleaned, purged of natural gas, isolated from interconnections with other pipelines, and sealed without removing the pipe from underground. Normally a positive pressure of an inert gas (e.g., nitrogen) is installed, in case the pipe could be used in the future or to monitor damage. This approach generally minimizes surface disturbance and other potential environmental impacts. The aboveground pipeline at compressor and meter stations would be completely removed, including all related aboveground equipment and foundations, and the station sites restored to their original condition as closely as possible.

Upon abandonment of the pipeline, in part or in whole, the ROWs associated with the abandoned facilities are normally returned to the landowners/land management agencies according to the specific easement agreements with the landowners/land managing agencies. However, on federal lands, the pipeline ROW could be used for another utility ROW (e.g., fiber-optic lines) depending on future decisions.

Abandonment of the pipeline facilities would be subject to the approval of the FERC under Section 7(b) of the NGA and would comply with DOT regulations and specific agreements or stipulations made for the pipeline ROWs. An environmental review of any proposed abandonment is conducted when the application is filed with the FERC.

3.4 CURRENT MITIGATION AND BEST MANAGEMENT PRACTICES

The Natural Gas STAR Program sponsored by the EPA is intended to reduce methane emissions from the oil and gas industry. More than 70 exploration, production, transmission, and distribution companies are involved, with the goal of identifying industry best management practices to reduce methane emissions (NaturalGas.org 2004a).

Best management practices (BMPs) include activities such as a set of cost-effective, widely applicable methane emissions reduction opportunities/options aimed at reducing leaks and process venting from the largest sources, which were jointly identified by EPA and gas industry representatives (EPA 2003). They include the following activities for transmission pipelines:

- Implement directed inspection and maintenance (DI&M) programs at city gate stations and surface facilities.
- Implement DI&M programs at compressor stations.
- Use turbines at compressor stations for new installations.
- Identify and replace high-bleed pneumatic devices.
- Identify and implement additional activities or partner-reported opportunities that can reduce methane emissions profitably.

3.5 RELIABILITY AND CONGESTION ISSUES

Insufficient infrastructure can cause pipeline congestion, temporarily forcing prices higher. There is little congestion on the natural gas pipeline network because investment in natural gas pipeline capacity has proceeded reasonably well in the United States.

Historically, the FERC has chosen to allow gas pipeline owners to obtain rates of return on equity that are at the high end of a zone of reasonableness because FERC has been very focused on stimulating investment, reducing congestion, and increasing reliability (Joskow 2005).

The deregulation of the natural gas industry in the United States has given free rein to market forces in most of the industry. The main goal of deregulation was to liberalize natural gas trading and supply, the industry segments with the greatest potential to operate as competitive markets.

3.6 TRANSMISSION ENHANCEMENT TECHNOLOGIES

In December 2004, six new projects with a total value of nearly $11.3 million were selected by the U.S. Department of Energy (DOE) to develop advanced technologies to enhance the integrity, reliability, and security of the nation’s natural gas pipelines. The projects include technology innovations, such as robotic platforms that are self-adjusting and -aligning and can navigate through plug valves; pipeline diameter reductions and expansions; and various types of pipeline bends (DOE 2006).

Other DOE projects involve developing advanced compressor technology to increase the capacity of the nation's existing natural gas pipeline infrastructure without adding compression units. An example is a DOE-funded project with the Colorado State University, which successfully field-tested an innovative commercial-scale pipeline compressor in Window Rock, Arizona, in September 2004 (DOE 2006). This new compressor uses micro-pilot ignition of diesel fuel, which injects micro-liter quantities of fuel into the compressor engine to initiate ignition, minimizing the inconsistent combustion associated with slow-speed, reciprocating natural gas compressor engines. The new compressor engine operates more efficiently, reducing operation costs, compressor engine emissions, and fuel consumption.

Another DOE project is investigating the use of unmanned aerial vehicles equipped with laser-based leak detection technologies that may make it possible to detect leaks from altitudes greater than 50,000 feet.

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