CHAPTER 5

TRANSFER AREAS

5.1. INTRODUCTION

Transfer areas apply to oil and hazardous substance (HS) bulk plant loading and unloading areas, in-plant closed transfer process and piping systems, dispensing stations, and non-bulk loading and unloading areas. Bulk oil and HS product and waste transfer operations routinely take place in the vicinity of the storage tank and at remote tanker loading and unloading areas. Non-bulk transfers take place at HS storage areas, hazardous waste (HW) accumulation storage points, and other container storage sites. Oil transfer areas are subject to specific spill prevention, control and countermeasure (SPCC) requirements. Area related guidance is a general SPCC guidance which addresses multiple regulations, not just 40 CFR 112. HS transfer areas are included based on best engineering practices.

Bulk oil is usually delivered to a naval area by marine craft, tank truck, railroad tank car, or pipeline. Bulk HS is delivered by a tank truck or delivered in 55-gallon drums by a truck. Oil is normally stored for transfer to aircraft, automobiles, military vehicles, construction equipment, ships, and portable storage units. HS is stored for transfer to the end user, or a processing plant.

Transfer operations may be performed by gravity or with the use of pumping systems, or a combination of both. Transfer equipment can be sophisticated, such as a multi-valved, manifolded loading/unloading rack servicing several tanks, or simple, such as a top port and bottom dispensing valve on a small aboveground storage tank. Equipment common to most transfer areas includes pumps, strainers, gauges, valves, filtration equipment, meters, loading/unloading arms or hoses, controls (pump start and stop switch,), and associated piping and instrumentation (tank-level indicators/alarms). Pumping systems are typical of bulk oil and HS storage tanks, industrial waste treatment plants and shop processes, where transfer operations are conducted under monitored conditions.

Some areas use the same equipment, such as loading/unloading racks, to receive and dispense the oil and HS. Other areas receive the oil and HS at one point and dispense it from another. One example is a gas station that receives oil at a ground level fill port and dispenses it through gasoline pumps. Another example is a small aboveground horizontal tank which is simply loaded through a top port and dispensed through a bottom valve.

Oil and HS spills at transfer areas most commonly occur when transfer hoses are disconnected, tanks overflow during filling operations, pumps break or leak, and transfer lines or hoses leak or rupture while in use. This chapter presents the criteria to evaluate the adequacy of oil and HS transfer areas and suggests possible corrective actions. In the evaluation of an area's transfer system, the following SPCC criteria elements should be considered: pipeline structural stability, corrosion protection, pipeline testing, pipeline identification, out of service pipelines, couplings, transfer pump operation, overfill protection, traffic collision protection, vehicle positioning and early departure prevention, marine receiving areas, and tank car and tank truck loading/unloading rack requirements.

5.2. PIPELINE STRUCTURAL STABILITY 112.7(e)(3)(iii)

Oil and HS transfer pipelines can be aboveground, underground, or both. Typically, underground pipe networks service underground tank installations, while aboveground storage tanks will have either aboveground or underground piping. Pipelines are constructed of carbon steel, stainless steel, fiberglass reinforced plastic (FRP), or polyvinyl chloride (PVC). Flexible piping is also used where applicable. For example, fuel hoses are made of flexible piping used to make connection between the steel piping and the tank cars, trucks, and vessels.

Pipelines must be properly designed and supported to prevent stress failure. Support integrity, support spacing, and pipeline expansion and contraction caused by thermal reaction of contained substance are the most important areas of concern in preventing spills due to pipeline failure. To meet the requirements of 40 CFR 112, the pipe supports should be evaluated for axial movement, loading, abrasion, and corrosion.

5.2.1. Support Integrity

Aboveground piping is preferred where it is not aesthetically objectionable or when it may be subject to physical damage, either accidental or deliberate. Pipe supports carry the structural load of the aboveground pipeline and protect aboveground pipes from corrosion through soil contact. Pipe supports may consist of concrete piers, hangers, metal supports, straps, rollers, cradles, or a combination of these. Figure 5-1 shows a typical pipe support.

Aboveground piping supports the bottom of the pipe to ensure piping is approximately 18 inches above the ground. In areas subject to flooding, greater clearance may be desirable. Piping on supports, both insulated and non-insulated, should rest on a steel shoe welded to the bottom of the pipe. The shoe should be left free to move on the support. Anchors and guides may also be required to control movement in long runs of straight pipeline, or near a connection to fixed equipment such as a pump or filter. Piping on piers shall be run above the pier deck whenever possible.

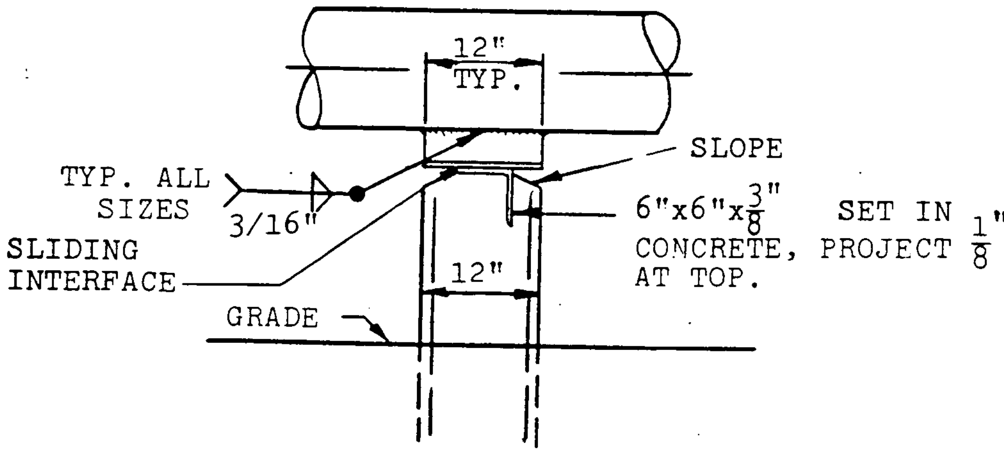


Figure 5-1
Typical Pipe Support

Aboveground pipe supports should be designed in accordance with DM-22 and constructed with good structural practice. If not designed and maintained properly, pipe supports can damage or stress a pipeline by severely restricting the natural movement of the pipeline and can damage the pipeline when it does move, or by serving as a place for water to collect and cause corrosion. 40 CFR 112(e)(3)(iii) requires that pipe supports should minimize abrasion, corrosion, and allow for expansion and contraction.

Paint or debris can lock the pipeline to the support. Signs of abrasion such as scarring, scratches, or exposed pipe metal can also indicate lack of free axial pipeline movement or overloading. Felt pads are often used between steel pipes and concrete supports; the condition of these pads should be checked regularly.

If a pipeline carries a different substance other than that for which it was designed and the new substance is heavier than the original, then the pipe supports may be loaded beyond their capacity. Pipeline supports are designed to support the load of the substance and the pipeline.

When a support fails, the loading on the other supports increases, and a section of pipeline is under excessive stress due to the lack of support. Pipe supports should be inspected regularly and repaired when broken. Unsupported pipeline sections should be examined closely to observe any excessive movement and excessive wear at pipe support interfaces and for leaks at pipe joints.

5.2.2. Support Spacing

The type and spacing of pipe supports depends upon the pipe size and the applied static and dynamic loads. Static loads include the weight of the pipe and the product it carries. Dynamic loads include vibration, collision, hydraulic surges, and thermal expansion and contraction. Improperly spaced, constructed, or maintained pipe supports can lead to pipe failure and a spill. If pipe supports are not adequately spaced, intermediate supports can provide the proper spacing. Table 5-1 lists suggested pipe support spacing as a function of pipe size, pipe type, and support conditions. The recommended pipe support spacing presented in this table should not be considered as absolute. Minor variations can be tolerated without jeopardizing the integrity of a piping system.

5.2.3. Pipeline Expansion and Contraction

Both the pipeline and the material transported may expand and contract due to changes in process or ambient (air or ground) temperature. Piping systems must allow for thermal expansion and contraction to avoid harmful stresses. Roller or hanging pipe supports provide free axial pipeline movement and are preferred over other types of pipe supports. Another acceptable arrangement is a small skid welded to the bottom of the pipeline which slides in a grove on the pipe support. Improvised pipe supports, such as resting pipes on railroad ties or tires, are unacceptable. As pipeline diameter decreases, movement becomes less of a concern because smaller pipelines generally have shorter pipeline lengths, lower flow rates, and smaller product temperature ranges.

Evidence of broken welds, scrapes, and visible bows in pipeline sections may indicate a support is not properly designed for expansion and contraction forces. If adequate provisions for pipeline expansion and contraction over a pipe support do not exist, it may have to be modified or replaced. A slip plane underneath fixed supports to allow for the free movement of a pipeline can be a simple and effective solution.

Substance expansion can also lead to excessive in-line pressures such as kinks in straight pipeline segments. Pressure relief valves or surge suppressers can be used to control stresses caused by substance expansion. Pressure relief valves should not be allowed to discharge to the atmosphere, storm drains, or sanitary sewers. Downstream piping leading to an atmospheric pressure tank, or drain lines leading to a surge tank are common ways to circumvent this problem. Pressure relief valves should not be used unless a pipeline segment can be isolated by valves and/or operating conditions require such valves (i.e. high expansion substance, high system pressure). Reducing system pressure or using reflective paints to reduce heat may be alternatives to pressure relief valves.

Reducing the length of straight pipeline segments by changing piping direction, offsets, loops, bends, and expansion joints can also be used to accommodate thermal expansion and contraction in pipelines. Loops and bends are more practical if space is available, and the segment is accessible. Installation of new pipeline segments or expansion joints should require no more than one day to complete following purging of the line.

The above guidelines are only intended to help identify potential structural instability problems. Corrective actions such as replacing or modifying a support, adding loops, bends, relief valves, or expansion joints to a pipeline should be evaluated and approved by design experts (chemical, mechanical, or structural engineers).

Table 5-1
Pipe Support Spacing

Pipe Size*	Schedule or Weight	Support Spacing (Feet) Continuous Spans	End Spans
1/2"	80 (xs)	8	5
3/4"	80 (xs)	10	7
1"	80 (xs)	13	9
1-1/2"	80 (xs)	18	12
2"	80 (xs)	21	14
2-1/2"	40 (STD)	21	14
	80 (xs)	25	17
3"	40 (STD)	23	17
4"	40 (STD)	27	20
6"	40 (STD)	32	26
8"	30	37	30
	40 (STD)	40	32
10"	30	40	33
	40 (STD)	43	35
12"	30	43	35
	(STD)	46	38
14"	20	43	35
	30 (STD)	48	39
16"	20	43	37
	30 (STD)	48	39
18"	20	35	37
	(STD)	51	41
20"	20 (STD)	49	41

* Welded Steel Pipe ASTM A53, Grade B; maximum temperature 150 °F; no

Source: DM-22 (Petroleum Fuel Areas).

5.3. PIPELINE CORROSION PROTECTION 40 CFR 112.7(e)(3)(i), 40 CFR 264.192(f), 40 CFR 280.20 (5)(b), 49 CFR 192(Subpart I), 195(Subpart D)

Pipelines, like tanks, are subject to corrosion, which can cause the system to deteriorate and result in a spill. Aboveground piping can be readily inspected and maintained. A common cause of corrosion on aboveground piping is the accumulation of drips of liquid (from rain or condensation) on the bottom surface of the pipe. When examining the pipeline's supports, check the pipeline for corrosion on its bottom surface.

40 CFR 112.7(e)(3)(i) states that new buried metallic piping should be protected from corrosion. Corrosion protection may consist of coatings, wrapping, painting, cathodic protection, or other effective methods. Buried pipeline that is exposed for repairs or improvements should be examined for evidence of corrosion. If corrosion damage is found, additional examination and corrective action should be taken. All underground or underwater pipelines or tanks should be painted, coated, or wrapped, and should also have cathodic protection.

One method of avoiding corrosion is to install FRP or PVC piping. If this is not feasible, there are two methods of pipeline corrosion protection: protective coating systems and cathodic protection. In the protective coating systems method, the coating acts as a buffer because the metal piping is no longer in direct contact with the corrosive environment. In the cathodic protection method, the metal pipe surface acts as the cathode, and a metal anode that is more negative is applied. The anode corrodes while the metal pipe cathode is protected.

5.3.1. Protective Coating Systems

Protective coatings work by creating a barrier to moisture, oxygen, and electrical current, thus, sealing the metal pipeline from the corrosive environment. Protective coatings are applied to protect both exterior and interior surfaces.

According to DM-22 and good engineering practice, the exterior surfaces of all underground steel piping systems should be protected by either an extruded polyethylene coating system or a coal tar double-wrapped felt system. Field joints and irregular shaped fittings can be protected with pressure-sensitive organic plastic tape. All exterior surfaces of aboveground steel piping systems should be protected by a coating of a zinc-rich primer, one bond or tie coat, followed by two or more coats of vinyl paint. For recoating of existing piping under a pier, greased absorbed wrapping tape with 50 percent overlapping should be used.

A common location of pipeline corrosion is the point where aboveground piping enters the ground. In this situation, the pipeline should be wrapped several inches above and below the air-soil interface, as shown in Figure 5-2.

Most regulatory agencies require protective coating systems in conjunction with other forms of corrosion protection, such as cathodic protection. It should be noted that a good coating system will decrease the size and cost of the cathodic protection system that is needed and increase the life of the protection system.

5.3.2. Cathodic Protection

Buried piping can easily corrode if it is not properly protected. Cathodic protection prevents corrosion by making the entire surface of the metal pipe act as the cathode of an electrochemical cell. There are two methods of applying cathodic protection to underground metal pipelines: sacrificial or galvanic anodes, and impressed current. Figure 5-3 illustrates the localized corrosion of buried piping, while Figure 5-4 shows a common way to protect underground piping cathodically using sacrificial anodes.

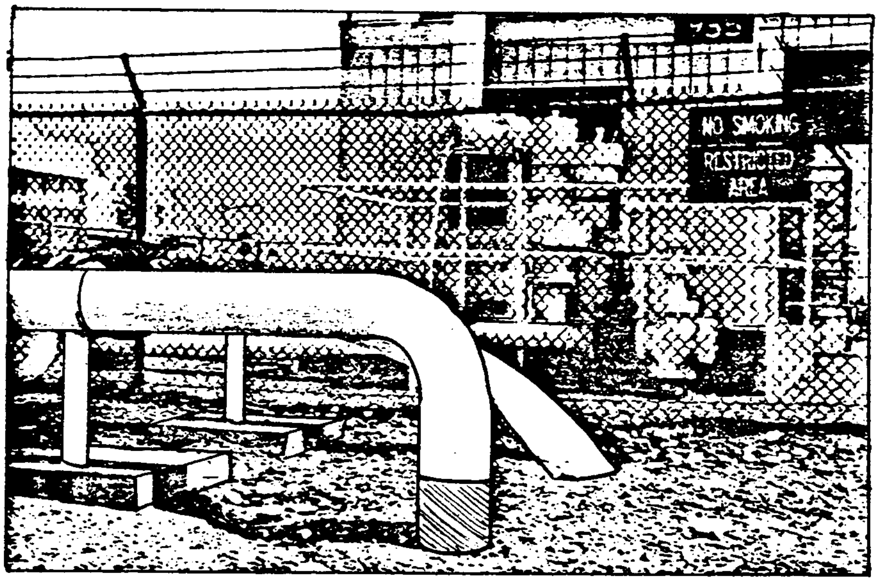


Figure 5-2
Piping Wrapped at the Air-Soil Interface

Another cause of buried pipeline corrosion is a long-range corrosion cell that is created due to a difference in terrain, as shown in Figure 5-5. In this situation, an impressed current system, illustrated in Figure 5-6, will protect the pipeline against corrosion.

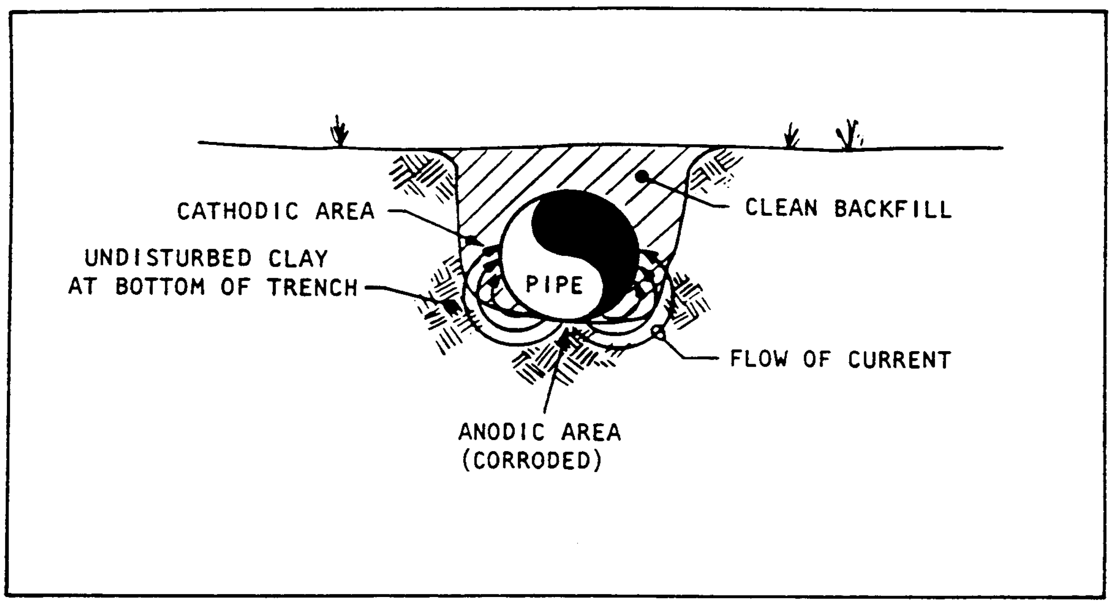


Figure 53
Localized Corrosion Caused by Soil Differential

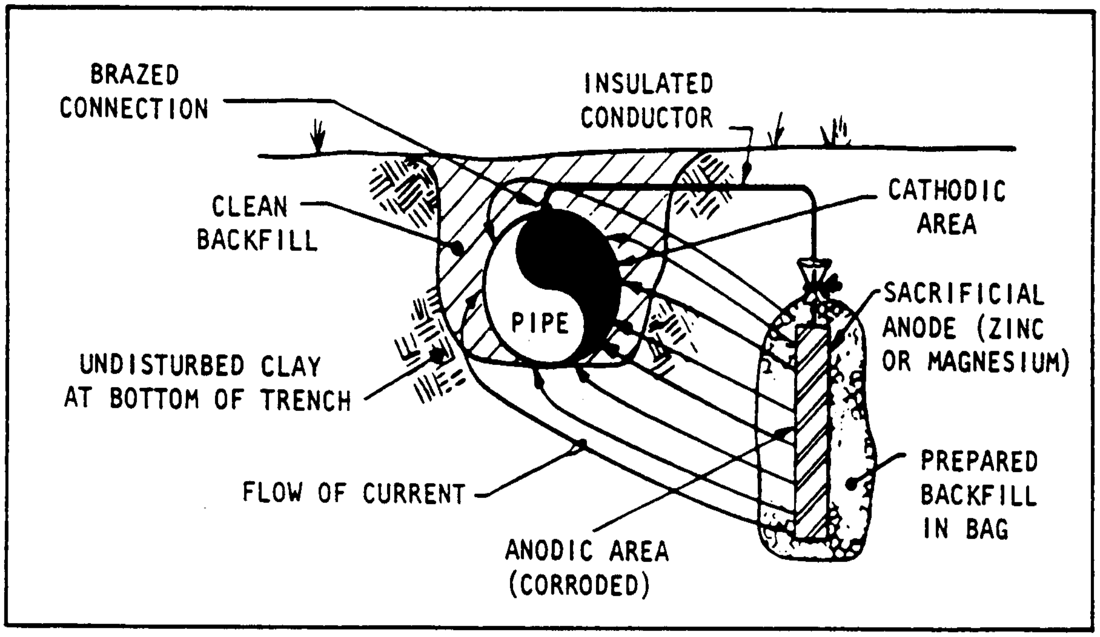


Figure 5-4
Cathodic Protection of Pipeline Using Sacrificial Anodes

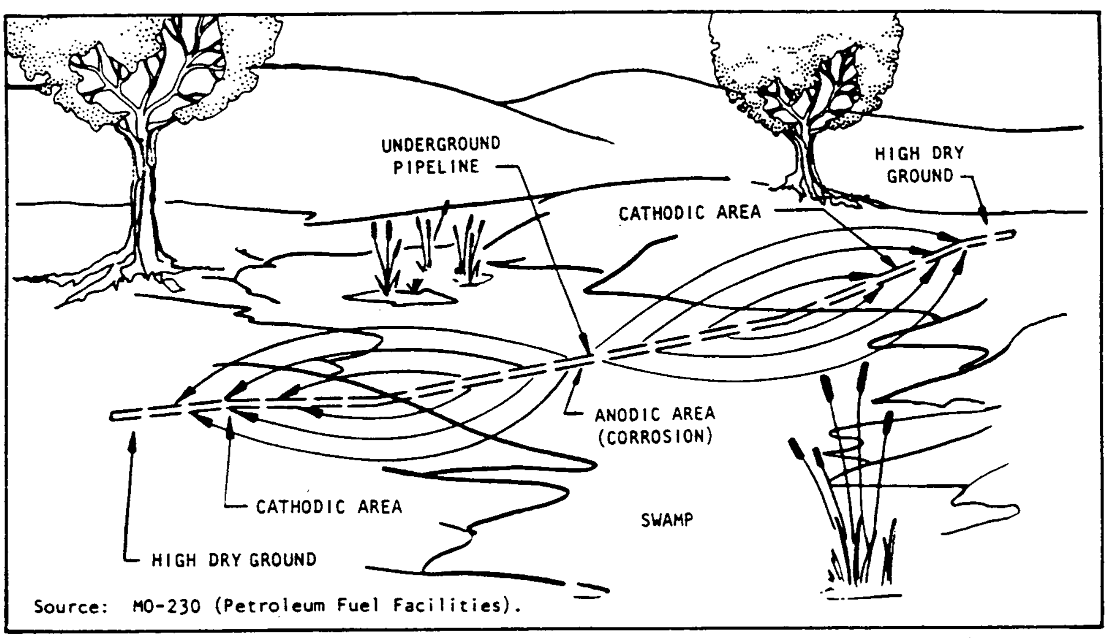
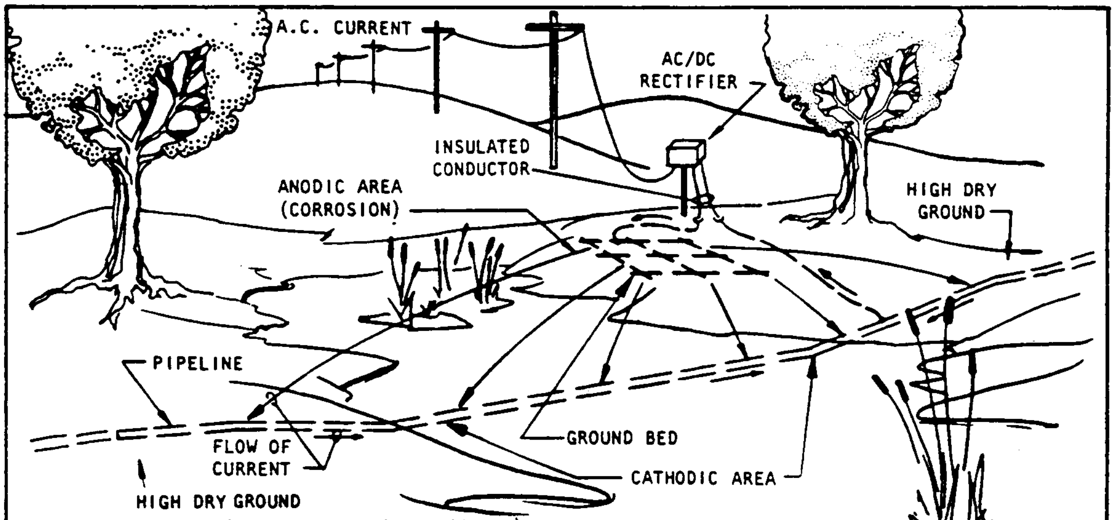


Figure 5-5
Long-Range Corrosion Cell Due to Difference in Terrain



Source: MO-230 (Petroleum Fuel Facilities).

Figure 5-6
Cathodic Protection of Pipeline Using Impressed Current System

Sacrificial or galvanic anode systems use a metal anode more negative in the galvanic series than the metal to be protected. The active metal anode corrodes (is sacrificed) while the metal pipe cathode is protected. This method protects localized "hot spots" in a pipeline, well-coated pipelines, and locations where the impressed current method poses a hazard.

The second method uses impressed current from an external source to reverse the flow of electrons and prevent corrosion. Impressed current anodes are made of relatively inert materials, such as carbon or graphite, and have a very low rate of corrosion. This method is used for large, bare, or poorly coated surfaces.

As a retrofit method, cathodic protection is particularly effective for underground applications where it is impractical to excavate and coat buried pipes. Cathodic protection is more effective and less expensive on coated structures, since the amount of protective current required is proportional to the amount of bare metal exposed to the corrosive media. Therefore, impressed current systems are usually the best retrofit for buried systems.

5.3.3. Corrosion Protection Testing and Inspection

As discussed in Chapter 4, all UST cathodic protection systems, including those installed in piping systems, must be inspected for proper operation and tested within 6 months of installation and at least every 3 years as required under 40 CFR 280.31.

5.4. PIPING SYSTEM TESTING 112.7(e)(3)(iv)

All aboveground pipelines and valves should be examined regularly by operating personnel. The general condition of flange joints, expansion joints, pipeline supports, valve glands and bodies, locking of valves, and metal surfaces should be assessed. In many cases, pipeline leaks go undetected, particularly when pipelines are buried or otherwise inaccessible. In such cases, a pressure test may be the only method for identifying a leak. 40 CFR 112(e)(3)(iv) recommends periodic pipeline pressure testing if a rupture of the pipeline could cause a spill event.

SPCC pipeline testing requirement is much less stringent than that required by DM-22, NFGS-15195, 49 CFR 192 (Subpart J), and 49 CFR 195 (Subpart E), and may already be met by activities performing pipeline tests as required. These regulations and specification methods meet or exceed SPCC requirements and provide direction for pressure testing. These guidelines also prescribe that safety relief devices used on liquid pipelines be pressure tested annually.

Corrosion, abrasion, and other forms of wear reduce the thickness of pipeline walls, which leads to pipeline failure. Consequently, conducting thickness tests can be a alternative method for determining pipeline integrity. Pipeline segments should be replaced when the pipeline wall thickness is below the retirement thickness.

For underground piping, however, testing the wall thickness is in most cases, impractical. If the soil conditions indicate a corrosive environment, periodic spot-checks of underground piping systems may be advisable. This requires uncovering the pipeline in selected locations and inspecting the condition of the exposed sections with visual examinations and thickness tests.

In recent years, a wide range of pipeline testing technologies has been developed. A summary of these technologies as well as older more established technologies is presented as follows:

Helium testing is used by injecting helium into a pipeline and using a hand held thermal conductivity sensor to sample for helium leaks along the pipeline. Since the sensor can only detect about 100 ppm and approximately 5 ppm of helium exists in the background, the pipeline must contain a very high concentration of helium and the samples must be taken near the pipe for this test to be reliable. Samples taken on a windy day are suspect. This test must be accomplished on completely empty pipelines since any liquids in the line could trap the helium from exiting the pipe. Several suppliers can provide this technology. The test is highly subject to human error and method of sample collection.

When conducting hydro testing, segments of the pipeline are blinded and tested with product or water at 1.5 times the normal pressure. Hydro testing has no leak location capability. The pipe system must be taken out of service for extended lengths of time. This can be an accurate test for piping as long as the test is conducted to eliminate air pockets, valve leaks and thermal effects. In many cases, hydro tests are not conducted properly or for an adequate length of time to allow for thermal equilibrium.

Hydrocarbon vapor monitoring employs a horizontal tube, buried with the pipeline, to collect vapor from the surrounding soil. This air or soil gas is sent to a metal oxide or infrared detector. This monitoring method can be effective with lighter products such as gasoline. Location is determined by timing the evacuation of the sample. Sensors will most likely not be able to distinguish current leakage from background contamination. Hydrocarbon vapors do not adequately transport through soil because they biodegrade within just a few feet of the leak source. Geology and the water table affect this method if it is relatively shallow in relation to the pipeline.

There are two types of liquid sensing cables that have been in use primarily for double-wall pipe interstitial monitoring. One technique is comprised of a pair of wires wrapped in a conductive polymer sheathing, which when in contact with hydrocarbons it expands to shunt the wires or close the circuit at that point. The location is accurately indicated to within one foot based on Ohms Law and the known resistance per foot of the wires. The cable can be pulled through a conduit along a pipe so that it can be removed for inspection and replacement. Water and hydrocarbons are detected with two different cable types.

The second method employs a coaxial cable which when immersed in liquids changes impedance and acts as an indication of leakage. Its sensitivity will vary with the length of cable installed and it must be buried directly along the pipeline. Therefore, it cannot be removed without excavation. Water and fuel may be detected with the same cable making it difficult to distinguish between the two at times. Connections are problematic and may cause false alarms. Since the detection of the leak is dependent on a direct contact with the liquid, placement of the cable is very important with regard to water table and geology.

Mass balance technology employs meters at each end of the pipeline to measure and compare throughput. The sensitivity of this approach depends on the accuracy of the meters, length of the pipeline, and temperature changes in the product. Leak sensitivity is usually stated in the range of 0.1 to 1 % of the flow rate. Monitoring pressure and temperature can enhance this method. It will also, when coupled with a computer, allow for rapid response for closing valves or turning off pumps. The one drawback to this technology is that there is no leak location capability.

Pressure sensors located along the pipeline are used to model pipeline changes. The sensitivity is a function of pipeline length, temperature, and product. Using standard physical laws, temperature corrected pressure is translated into pipeline leak status in the range of 10 to 50 gallons per day. Leaks cannot be accurately located with pressure monitoring. Monitoring flow and temperature can enhance this method. Pressure sensors provide rapid response for shutting motorized valves or turning off pumps.

Rarefactive Wave is a “sonar” type system that uses dynamic pressure sensors similar to microphones to detect the wave front of a negative pressure wave traveling down the pipeline from the point where a leak or pipe breach occurs. This is a real time measurement of the time the wave front reaches each pressure sensor so that location can be accurately reported. The sensitivity of this test is 24 gallons per day. Sophisticated software will nullify extemporaneous noise from pumps or valves. This method will provide rapid response for system shut down and will locate the leak to within a few feet of actual location.

Tracer technologies employ a volatile chemical marker that is added to the product. Air is sampled along the pipeline through hollow probes for the presence of the marker. This method is similar to hydrocarbon monitoring only in the way the samples are collected. The tracers, unlike hydrocarbons, are less prone to bio-degradation. They can, therefore, be seen at much greater distances from the leak source. This fact, along with the high sensitivity of the detector, allows for the detection of very small leak rates. This can be applied as a one-time test or for continuous monitoring. The sensitivity is 1 gallon per day and leaks can be located to within a few feet before excavation. The pipeline system remains in service during the test. Background contamination does not interfere with this technology.

Volumetric methods of leak detection will measure liquid lost under pressure to determine leakage. Making measurements at two different pressures to reduce the thermal error enhances the accuracy. The pipeline system must be taken out of service during the test. All air pockets must be eliminated and the system must be flanged to eliminate valve leakage. Leaks cannot be located using this method.

5.5. PIPELINE IDENTIFICATION

Proper identification of pipelines, transfer hoses, and the type of substance they store is not required in 40 CFR 112; however, the improper loading and transferring of a substance due to unlabelled valves, controls, and portholes has resulted in spills. Fuel has accidentally been loaded into a storm drain when an untrained operator mistook it for the fill port for an underground storage tank. Oil has been discharged from a tank vent because the operator could not identify the proper control valve after the overfill alarm sounded. Operator errors such as these can be prevented if pipelines and equipment are properly identified. DOT and NFPA labels, color coding, and MIL specification labels are methods widely used in the Navy. Matching couplings and color coding of transfer lines are very effective means of preventing incompatible mixing and product contamination.

Pipelines should be clearly marked to identify the specific product. Pipeline identification can include color-coding, banding, or labeling. MIL-STD-101B is the standard for color coding pipelines, and MIL-STD-161F is the standard for new pipeline labeling. These standards should be followed for all piping, including new and existing pipelines. In addition to pipelines, all valves, pumps, meters, and other items of equipment shall have easily discernible painted numbers, numbered corrosion-resistant metal, or plastic tags attached with a suitable fastener. Numbers shall correspond to those on the schematic flow diagrams and other drawings for the installation.

MIL-STD-101B establishes, defines, and assigns a color for recognition to each of six classes of materials. Five of the classes represent universally recognized hazards involved in the handling of dangerous gases and liquids. The sixth class is for the exclusive use of fire protection materials and equipment. This basic color code requires application of color warnings in a distinctive manner as a visual aid and supplements the identification markings on compressed gas cylinders and piping systems.

A primary color identifies the safety hazard. These colors appear as a circular band on piping systems and as main body, top, or band colors on compressed gas cylinders. Secondary colors appear as arrows (or triangles) on piping systems and as main body, top, or band colors on compressed gas cylinders and identify other hazards. The identifying color is for identification purposes only and not as a substitute for protective coatings. Table 5-2 presents the colors used as both primary and secondary warnings.

Table 5-2
Pipeline Warning Colors

Color	Material	Warning
Yellow, No 13655	flammable materials	all materials known ordinarily as flammables or combustibles
Brown, No 10080	toxic and poisonous materials	all materials extremely hazardous to life or health under normal conditions as toxics or poisons
Blue, No 15102	anesthetics and harmful materials	all materials productive of anesthetic vapors and all liquid chemicals and compounds hazardous to life and property but not normally productive of dangerous quantities of fumes or vapors
Green, No 14187	oxidizing materials:	all materials which readily furnish oxygen for combustion and fire producers which react explosively with the evolution of heat when in contact with many other materials
Gray, No 16187	physically dangerous materials	all materials, not dangerous in themselves, which are asphyxiating in confined areas or which are generally handled in a dangerous physical state of pressure or temperature
Red, No 1110	fire protection materials	all materials provided in piping systems or in compressed gas cylinders exclusively for use in fire protection

Pipeline, equipment markings, and labels should be clear, legible, and in conformance with MIL-STD-161F. MIL-STD-161F specifies that petroleum products, piping, equipment, and hydrocarbon missile fuels fall within the yellow color code classification of materials. Lettering should be white gloss letters on a black background. Criteria for proper markings and labels, as well as examples of typical pipeline identification for fuel and petroleum products are shown in Figure 5-7.

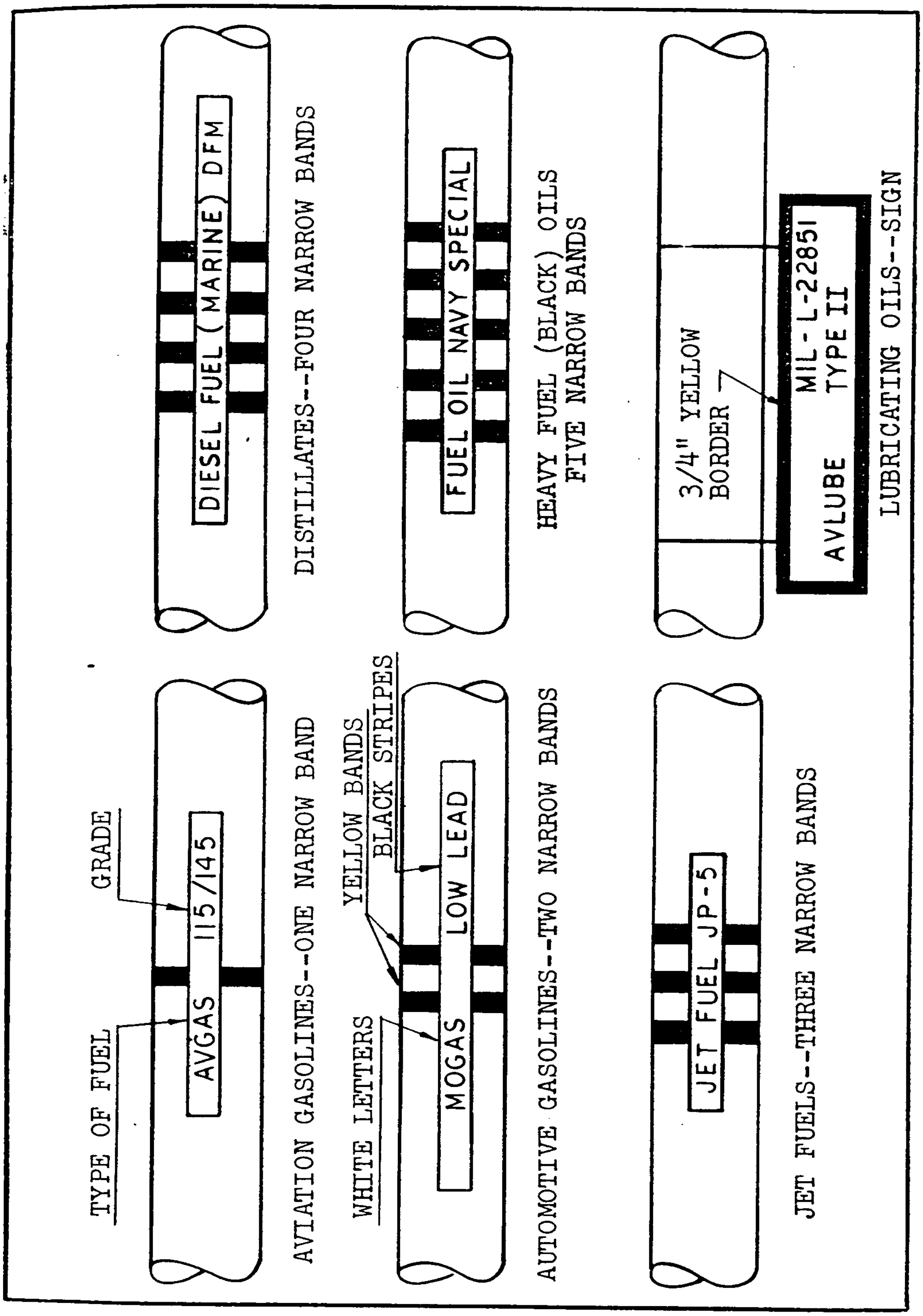


Figure 5-7
Pipeline Identification

If an area pipeline lacks proper marking and labeling, determine if the pipe network can be clearly understood upon visual inspection. Consider the number of different types of oil and HS pipelines at the area. Pipeline marking becomes more critical as the complexity of the pipe network increases.

5.6. OUT OF SERVICE PIPELINES 112.7(e)(3)(ii)

SPCC regulations require pipelines that are out of service, or in standby service for an extended period of time, to be capped or blank-flanged at the terminal connection. This prevents any release, either due to operator error or vandalism. In addition to being capped or flanged, the pipeline should be marked as to it's origin.

5.7. COUPLINGS

Using couplings equipped with valves, to block the flow when a hose is disconnected can prevent oil and HS transfer spills. The types of couplings normally used for loading and unloading operations include:

- Ordinary quick-disconnect couplings. These couplings are commonly used because they are light and easy to handle. However, they do not provide for spill control, and precautions (i.e. drip pans) must be taken to prevent spill of material remaining in the transfer line.
- Quick-disconnect couplings equipped with shutoff valves. These couplings reduce the volume discharged when hoses are disconnected but do not eliminate it.
- Dry-disconnect couplings. These couplings are equipped with a spring-loaded valve to blocks the flow when the transfer line is disconnected. Dry-disconnects are preferred since they reduce the volume of product spilled.

These types of couplings and their applications are summarized in Table 5-3. Figure 5-8 illustrates various types of couplings and material losses that can be expected for each type.

If a transfer operation does not use couplings with spill control valves, the operation must be reviewed to determine the potential impacts of not having them. Low-pressure flow rates may be controlled with drip pans, but this is not a recommended practice as it increases the spill potential. Drip pans should be used only as a temporary solution to dripping valves. If excess product after disconnection is greater than 1 gallon at each end, couplings with spill control valves should be installed. Dry-disconnect couplings are generally more cost-effective than ball valves, but operational and compatibility problems (e.g., operating pressures) may prevent their use. The quick- and dry-disconnect valves must be compatible with the oil or HS transferred. Matching couplings or hose identification should be used where incompatible HS could be mixed during transfer.

Table 5-3
Types of Couplings And Their Applications

System	Function	Spill Control	Applications
Ordinary Quick-Disconnect Coupling	Product transfer	None	Tank vehicles and storage tanks
Quick-Disconnect Coupling	Product Transfer	Built-in valve reduces spills from disconnect hoses	Tank vehicles and tanks
Dry-Disconnect Coupling	Product transfer	No spills from disconnected hoses	Tank vehicles and storage tanks
Emergency Shutoff Valves	Flow control	A fusible metal link melts and closes the valve in case of fire or impact	For use in any place where it is important to stop flow

Source: Technology for the Storage of Hazardous Liquids: A State-of-the-Art Review. New York State Department of Environmental Conservatism, 1983. Used by permission.

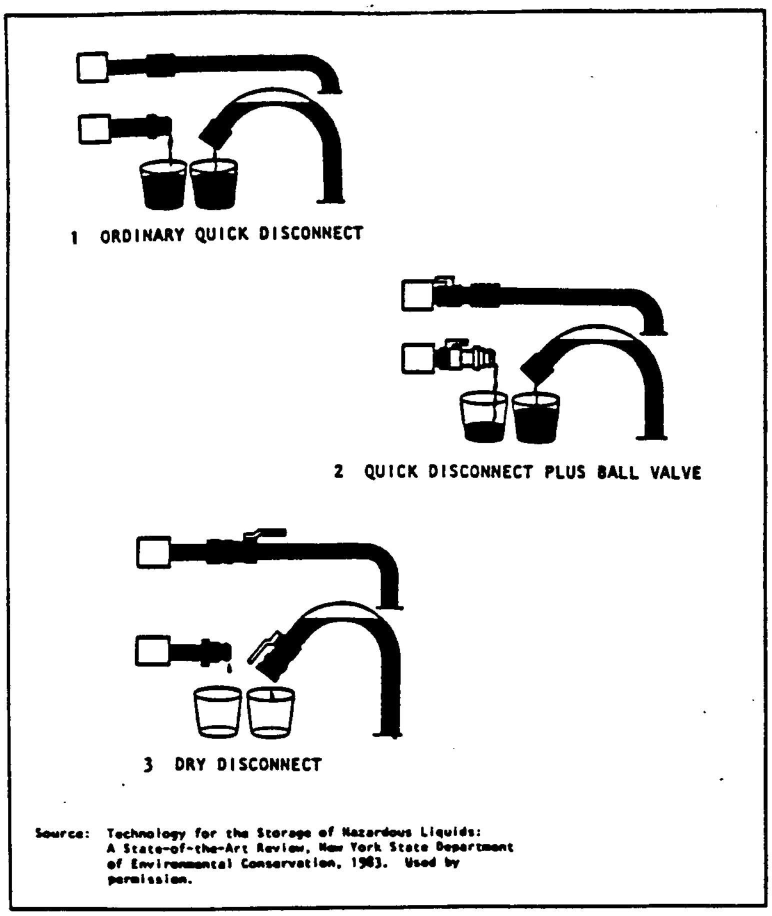


Figure 5-8
Types Of Couplings And Associated Material Loses

Factors to consider when evaluating or selecting couplings for a particular application include temperature, pressure, and material transfer properties. The higher the temperature or pressure, the more securely attached the couplings should be. Hose-coupling connections are the weakest link during transfer operations. As a rule of thumb, bolt clamp connections perform well with low pressures, band connections with low to medium pressure, and interlocking clamps with high pressures.

5.8. TRANSFER PUMP OPERATION 112.7(e)(9)(iii)

Transfer pumps vary depending upon the type of service or particular application. Pump seals and materials of construction must be designed for and compatible with the substance handled. DM-22 provides design requirements for fuel transfer pumps. Use of automatically controlled pumps are recommended to shut down pump operations to avoid overfill and spills. As discussed in Chapter 4, pump cutoff devices are connected to the storage tank high-level alarms and inlet control valves.

Installation, operation and maintenance of transfer pumps should follow the design and the manufacturer's instructions. Proper maintenance procedures will prevent operational pump leaks. An additional SPCC pump operational requirement [40 CFR 112.7(e)(9)(iii)] states that oil pump starter controls should be locked in the "off" position or be placed in a location only accessible to authorized personnel when in non-operating or standby status.

5.9. OVERFILL PROTECTION

Overfill prevention systems prevent accidental tank overflow during filling operations, control spills during pipe disconnection, and prevent overflow from surface impoundment. Overfill protection equipment is installed in storage tanks to shut off product transfer before overfill. These devices include level alarms, pump shut-off devices, and automatic control valves at tank inlets. Overfill can be avoided by checking tank volume prior to product transfer and monitoring the volume during the transfer operation.

RCRA regulations, 40 CFR 264.192, require the use of appropriate controls and practices on HW storage tanks to prevent overfilling. For uncovered tanks, the regulations require maintenance of sufficient freeboard to prevent overtopping by wave or wind action or by precipitation. While not specifically required under the CWA, overfill and transfer spill prevention systems are required for all HS tanks to comply with the intent of the law to prevent HS releases. The methods and equipment presented in this section have proven very effective in achieving this objective.

The complexity and cost of an overfill prevention system depends upon the potential effects of overfilling (rate of release, substance stored and hazards it poses, potential environmental effects, lack of secondary containment, etc.), and may be subject to the local enforcement agency approval. For instance, a small HW accumulation tank may require an operator with a dipstick or a level sensor/gauge to monitor the liquid level during loading operations. In contrast, a large industrial waste treatment plant with various interconnected storage and process tanks may require computerized interlocking provisions for automatic shutoff.

5.10. TRAFFIC COLLISION PROTECTION 112.7(e)(3)(v)

Aboveground oil or HS pipelines can cause significant spills if ruptured, especially when product is flowing through the lines. Consequently, 40 CFR 112 requires that vehicular traffic should be warned verbally or by appropriate signs to be sure that the vehicle would not damage aboveground piping.

Warning signs should be placed at a height and location visible by truck drivers sitting in their truck. Warning signs at the entrance of an area should state the minimum clearance height of overhead pipelines. Similar signs should be placed at the approach to overhead pipelines. In addition to specifying the presence and location of pipelines, the signs should emphasize driver caution and observation of the speed limit.

A clearance bar or dangling chains located at the area entrance at a approximately 6 inches lower than the lowest overhead pipeline also warn a driver of a potential collision. At areas with large paved areas, the route to the loading racks should be painted on the pavement.

Dents, dings, and scratches in the equipment indicate damage by loading/unloading vehicles. Observing the transfer operations helps determine if adequate collision protection exists. As the vehicles approach and depart, there should be adequate clearances between the vehicles and equipment.

To reduce the potential for a traffic collision, physical barriers such as curbs and crash posts can be installed to protect pipelines. Physical barriers should protect tanks, pipes, pumps, racks, fill ports, valves, and other sensitive equipment. Traffic collision protection is a smart and cost-effective way of preventing costly spills and equipment damage.

Crash posts generally consist of brightly marked hollow steel posts filled with concrete. Crash posts should be located such that they protect the equipment involved without interfering with transfer operations. Figure 5-9 is an example of the use of crash posts. In this illustration, crash posts are located at a refueling point to protect the transfer equipment, yet they allow for the unimpeded movement of tanker trucks to the refueling points. Areas with massive equipment, such as cranes, may require crash posts as large as 1 to 3 feet in diameter to withstand a collision.

Crash posts are generally more economical than curbs. However, curbs may become more attractive when used for traffic collision protection and other purposes (secondary containment, site drainage, preservation of roadway foundation, etc.). Concrete curbing is an effective protective barrier at areas where vehicles are small or pipelines are less susceptible to collision. Figure 5-10 shows concrete curbs protecting fuel transfer equipment at a refueling point. The curbs protect the fuel meters, valves,

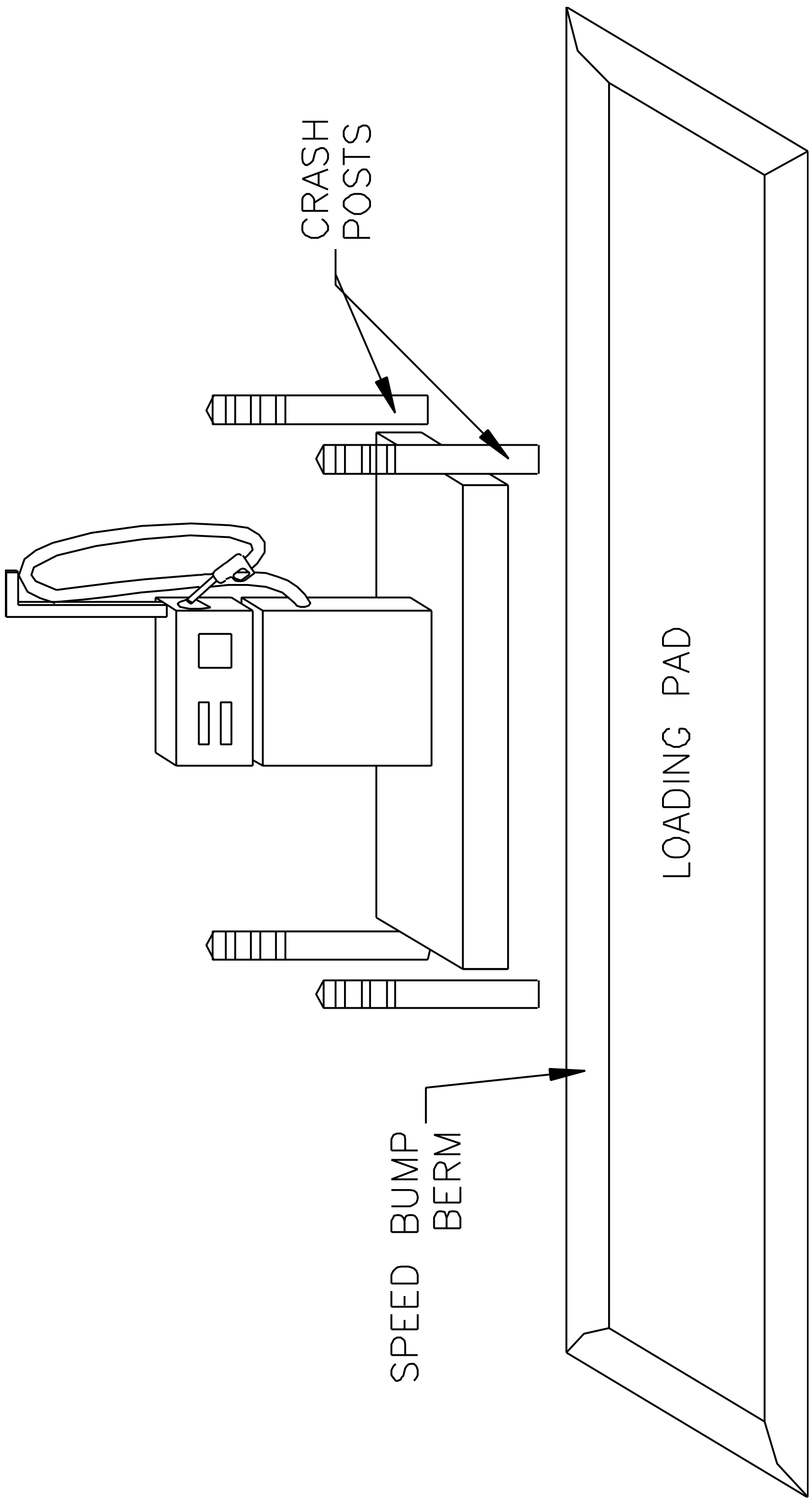


Figure 5-9
Use of Crash Posts

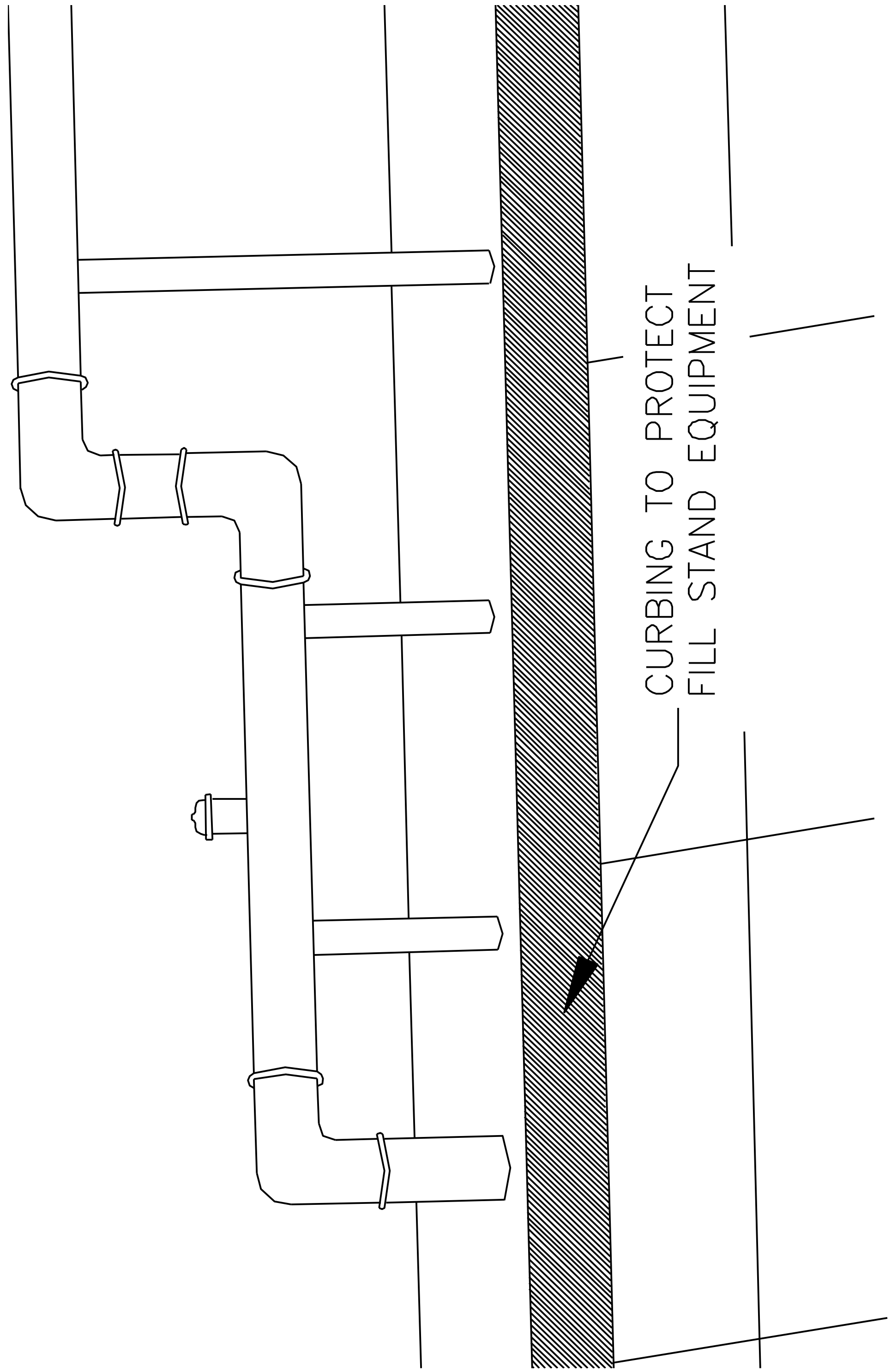


Figure 5-10
Use of Curbs to Protect Fuel Transfer Equipment

and other equipment on the fill stand. Curbing at loading racks is often incorporated into the curbing for spill containment (Chapter 7).

Where adequate clearance or protection cannot be provided, traffic may have to be rerouted. A final consideration may be to relocate a section of pipeline. However, because relocating a pipeline is costly and requires shutting down and purging the entire pipeline, this alternative is attractive only if other deficiencies require replacement.

5.11. VEHICLE POSITIONING AND EARLY DEPARTURE PREVENTION 112.7(e)(4)(iii)

Proper vehicle positioning at loading/unloading areas is essential to spill prevention. Vehicles should be parked in areas with secondary containment or flow diversion systems. Bulk transfer operations should be conducted only in areas equipped with such protection.

A vehicle leaving a transfer area before disconnecting hoses and securing valves is a common cause of spills; 40 CFR 112 recommends an interlocked warning light, physical barrier system, or warning signs at loading and unloading areas. Physical barriers and wheel chocks provide safeguards against accidental vehicle movement. Interlocked warning lights to prevent vehicular departure before complete disconnect of flexible or fixed transfer lines can also be used.

5.12. MARINE RECEIVING AREAS

Typical marine receiving areas include fuel piers and wharves designed for dispensing and receiving fuel. These areas have separate piping manifolds for each fuel type. Spill prevention for these areas are subject to U.S. Coast Guard regulations (33 CFR 154) and NAVFAC P-272. Pump stations associated with these areas should have some form of spill containment.

5.13. TANK CAR AND TANK TRUCK LOADING/UNLOADING RACK 112.7(e)(4)(i)

Tank car and tank truck loading/unloading operations should meet the minimum requirements established by the Department of Transportation (DOT). Applicable DOT requirements include 49 CFR Parts 177.834 and 177.837, which apply to the loading and unloading of hazardous and flammable materials. The National Fire Protection Association, Inc. (NFPA) also have established codes (NFPA 30) for loading and unloading operations for flammable and combustible liquids. DOT and NFPA requirements are procedural and have been incorporated into the SPCC standard operating procedures that are presented in Appendix G.

Even though these requirements are mainly procedural, they require the installation of some equipment. For example, bonding cables are necessary to conduct proper grounding, and a "NO SMOKING" sign reminds operators not to have open flames near the loading/unloading area. Briefly, the minimum DOT requirements include:

- Setting vehicle hand break.

- No smoking or open flame within 50 feet.
- Operating the equipment within eyesight and 25 feet of the loading rack.
- Properly training the operator to operate the equipment and to be aware of potential dangers.
- Stopping the engine, unless the motor is needed and in operation.
- Grounding the vehicle and the rack to the earth, and bonding the vehicle and rack to each other.

Refer to the text of 49 CFR 177 for additional information.

SPCC regulations suggest that areas not draining into a catchment basin should have a quick drainage system capable of holding the maximum capacity of any single compartment of a tank car or tank truck being loaded or unloaded. Section 7 discusses possible containment structures that may be used for this purpose.