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Hazardous Liquid Pipelines - Basics and Issues

Much of the information included in briefing paper #2 on pipeline basics is the same for natural gas pipelines and hazardous liquid pipelines. This briefing paper focuses on the specifics of hazardous liquid lines.

What Do Hazardous Liquid Pipelines Carry?

Hazardous liquid pipelines, as defined in federal regulations, carry:

- **Crude oil**, with widely varying densities, viscosities, sulfur contents, and other properties, including bitumen (an extra heavy crude oil), which is typically diluted with condensates to make it flow through pipelines. "Sweet" crude refers to crude that contains little or no sulfur, while "sour" crude contains high concentrations of sulfur or hydrogen sulfide.
- **Refined biofuels and petroleum products**, including gasoline, diesel, jet fuel, ethanol, and home heating oil.
- **Highly Volatile Liquids** such as propane, butane, ethylene, condensates.
- **Supercritical Carbon dioxide; or**
- **Anhydrous Ammonia.**

One other liquid associated with oil and gas drilling that is frequently transported by pipeline is produced water or wastewater from drilling activities. This liquid is not currently regulated under the federal pipeline safety rules. States can regulate these lines if they choose, and spills of this produced water may fall under state and federal pollution regulations such as the Clean Water Act.

US Hazardous Liquid Transmission Pipeline Miles by Commodity

Data Source: US DOT Pipeline and Hazardous Materials Safety Administration
Data for 2017 as of 2/20/2019

Commodity	Interstate Miles	Intrastate Miles	Total Miles
BIOFUEL		15.0	15.0
CO2	4,039.6	1,197.1	5,236.7
CRUDE OIL	54,136.9	24,937.7	79,084.7
HVL FLAMM TOXIC	40,875.9	28,066.6	68,942.6
REFINED PP	51,852.4	10,496.7	62,349.1

Notes:

BIOFUEL is distilled from biological feedstock, such as corn and sugar. Examples include ethanol and biodiesel.

CO2 is carbon dioxide in the liquid state.

HVL FLAMM TOXIC includes Highly Volatile Liquids (HVL), flammable, and toxic liquids. HVL products form a vapor cloud when released to the atmosphere. Flammable products are defined in 49 CFR 173.120. Toxic products are defined in 49 CFR 173.132. Examples include propane, ethane, butylene, and anhydrous ammonia.

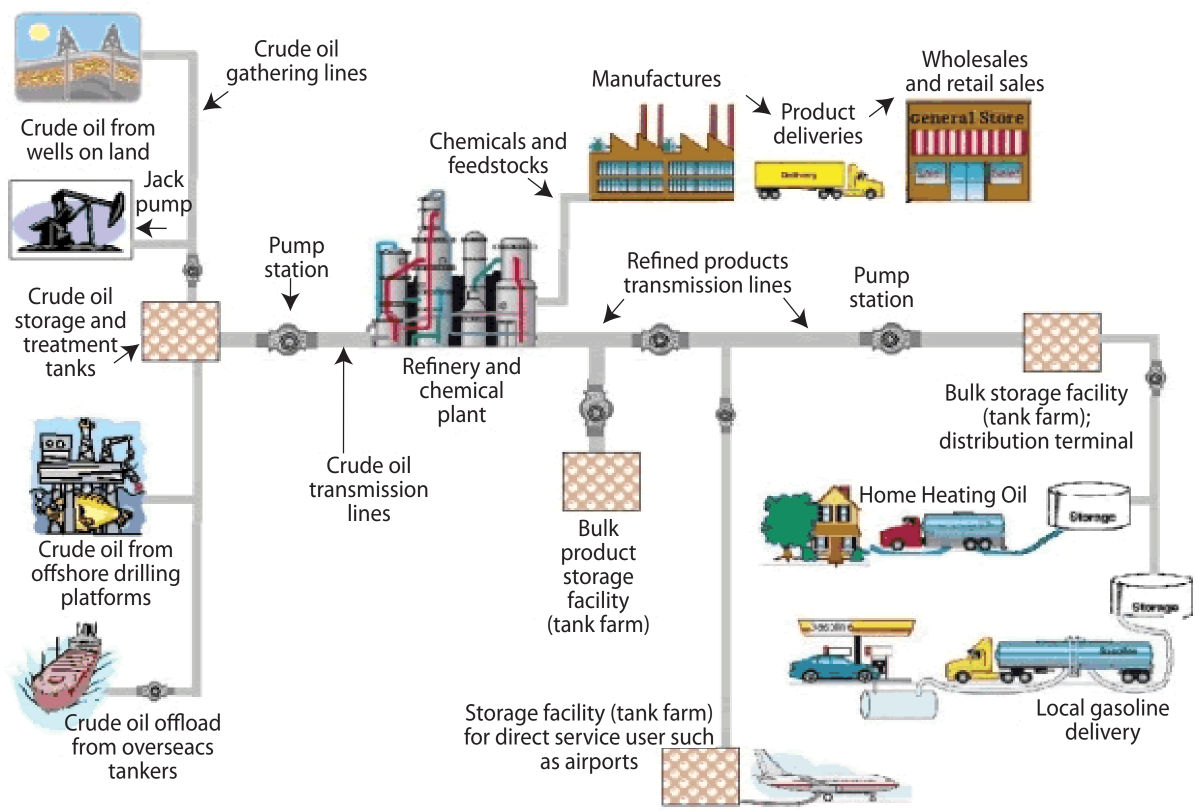
REFINED PP is petroleum products obtained by distilling and processing crude oil that are liquid at ambient conditions. Examples include gasoline, diesel, jet fuel, kerosene, and fuel oil.

If you are interested in seeing what types of materials the transmission pipelines in your state carry, you can choose to view the mileage of pipelines carrying each commodity in only one state or for all pipelines on PHMSA's page here.

How Hazardous Liquid Pipelines Work

Hazardous liquid pipelines operate and are constructed in the same basic way that natural gas lines are (see Briefing Paper #2).

Raw crude coming out of a well normally needs to go through separation to remove water and gas from the crude. Gathering lines bring crude oil out of production areas to larger transmission lines that often take the crude oil to refineries.



Source: PHMSA "Petroleum Pipeline Systems."
http://primis.phmsa.dot.gov/comm/PetroleumPipelineSystems.htm?nocache=6756

Once the crude oil has been refined, transmission lines carry the refined products to end-users or to storage and distribution facilities for transportation to consumers. The product is pushed through the pipeline by large pump stations situated every 20-100 miles along the line, depending on the product, terrain and pressure at which the pipeline is operating.

The machinery at the pump stations is normally controlled remotely at centralized control stations. Most liquid fuels move through the pipeline at between 3 to 8 miles per hour. It is estimated that the cost of transporting the crude oil and then the refined products through the pipeline network adds about two and a half cents to the cost of a gallon of gasoline at the pump.

A single pipeline can carry several different types of refined products in "batches," shown in an animated illustration here: https://pipeline101.com/How-Do-Pipelines-Work/What-Is-Batching

Typically, the pipeline operator does not own the product in the pipe; the operator simply gets paid to move the product from one place to another. Interstate transmission pipeline companies develop "tariffs" that are approved by the Federal Energy Regulatory Commission (FERC), that set the price for moving the product and describe the specifications that need to be met before the product can be transported through the transmission pipeline. These tariffs for crude oil for example would define things such as the allowable water and sediment content, temperature, density and viscosity of the crude. Companies normally publish their tariffs online, for example click here to see TransCanada's tariffs for their Keystone pipeline.

Regulations Affecting Hazardous Liquid Lines

Liquid pipelines, depending on location, are subject to regulations by the following agencies:

- Safety – PHMSA, States
- Spill Response – PHMSA, Coast Guard, States
- Spill Cleanup – EPA, Coast Guard, States
- Security – TSA and Coast Guard
- Pricing/tariffs – FERC
- Storage terminals – EPA
- Worker safety – OSHA
- Land use and environmental permits – Army Corps of Engineers, Forest Service, Fish and Wildlife Service, BLM, and state and local government.

Fewer states have chosen to seek any authority over the safety of hazardous liquid pipelines than over natural gas pipelines. Currently 15 states have some authority over intrastate liquid lines (compared to 48 states for natural gas lines), with only five states seeking any authority on interstate liquid transmission pipelines (compared to 8 for natural gas).

Major Pipeline Safety Requirements For Hazardous Liquid Pipelines

Integrity Management

Integrity management for liquid lines is similar to integrity management for natural gas lines, and is covered in briefing paper 10. Requirements for hazardous liquid integrity management plans have been in place since 2002, and apply to pipelines that could affect a High Consequence Area (HCA) in the event of a spill. For liquid lines, HCAs include defined densities of populated areas, unusually sensitive areas (USAs) like drinking water sources and commercial or recreational fishing areas, and commercially navigable waterways. Each covered pipeline segment must be re-assessed at least every 5 years. About 44% of all hazardous liquid pipelines fall within HCAs, so are covered by this program.

Identification of Threats and Repair of Pipelines Outside of HCAs

Identifying threats and repair of pipelines outside of the areas where integrity management requirements apply (HCAs) are left pretty much up to the good judgment of the pipeline operator. The regulations allow the operator to decide how to look for problems and what a "reasonable time" is to correct a problem that may be discovered. There are defined periods for inspections of things such as valves and regulators. The green box to the right provides the overarching regulation that puts the responsibility for safe operation and repair on the pipeline operator.

The Regulations

Repairs Beyond Those Required by Integrity Management 49 CFR 195.401(b)(1)

Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

Corrosion

The major corrosion protection items (coatings, cathodic protection, inhibitors) for hazardous liquid pipelines are the same as for natural gas pipelines. Corrosion is the deterioration of metal that results from a reaction with the environment which changes the iron contained in pipe to iron oxide (rust). For example, if your car develops a rust spot, that is corrosion of metal. The same process can occur in various forms on pipelines. As is the case with your car, there are effective methods for preventing and arresting corrosion damage to pipelines.

- *External corrosion* occurs due to environmental conditions on the exterior surface of the steel pipe (e.g., from the natural chemical interaction between the exterior of the pipeline and the soil, air, or water surrounding it).

- *Internal corrosion* occurs due to chemical attack on the interior surface of the steel pipe from either the commodity transported or other materials carried along with the commodity transported within the pipeline.

- *Other, more specialized types of corrosion* such as stress corrosion cracking, microbial corrosion, and selective seam corrosion can also occur. These types of corrosion can be exacerbated by environmental conditions, manufacturing processes and applied stresses resulting from routine and normal pipeline operations.

Corrosion can result in the gradual reduction of the wall thickness of the pipe and a resulting loss of pipe strength. This loss of pipe strength could then result in leakage or rupture of the pipeline due to internal pressure stresses unless the corrosion is repaired, the affected pipeline section is replaced, or the operating pressure of the pipeline is reduced. Pipeline corrosion creates weaknesses at points in the pipe, which in turn makes the pipe more susceptible to other risks such as third party damage, over-pressure events, etc.

Leak Detection

Operators are not currently required to have electronic leak detection systems on their pipelines. Leak detection sensitivity is a reflection of the systems' capability to detect a leak of a certain size in a predetermined time. While many operators do employ multiple leak detection systems there is no standard for how quickly they have to be able to identify leaks of any certain size. Small leaks are the most difficult to detect, and take the longest time to set off an alarm. Some small leaks may fall below the threshold of leak detection systems, due to pipeline hydraulics, accuracy of the detectors, and alarm thresholds. Even the best leak detection systems may not be able to detect "small" leaks under 3% of the volume of the flow through the pipeline.

The effectiveness of leak detection systems has been called into doubt by many incidents; for example:

• 2010 Enbridge spill in Marshall Michigan – over 800,000 gallons of crude oil spilled and went undetected by the company's leak detection system.

• 2010 Chevron spill in Salt Lake City – over 30,000 gallons of crude oil went undetected by the company's leak detection system.

• 2011 TransCanada Keystone I pump station leak – 21,000 gallons of crude oil was reported by a neighbor who saw a geyser of oil before TransCanada identified the leak and shut down the pipeline.

The 2011 pipeline safety reauthorization act included a provision calling for a study of the state of the art for leak detection systems on liquid lines, and standards and regulations for leak detection if appropriate. A study was completed in 2012 and delivered to Congress, but PHMSA has not yet established new standards or finalized new regulations on leak detection.

Valves – Type & Placement

Liquid lines have the same valve considerations as natural gas lines. If a pipeline should fail, how quickly the valves can be closed and the distance between the valves are some of the main determinations for how much fuel is released. One term you may run into is Emergency Flow Restricting Device (EFRD). For the most part EFRD is another term for a valve, and typically refers to either a check valve (a valve that allows fluid to only flow in one direction), or a remotely controlled valve that can be shut off from a control room. The placement of such valves near high consequence areas, particularly water crossings, can reduce the amount of fuel spilled if a pipeline failure should occur.

For liquid pipelines in 1992, 1996, 2002, and 2006, Congress required PHMSA or its predecessor to "survey and assess the effectiveness of emergency flow restricting devices" with the first such requirement having a deadline in 1994. Following this analysis, Congress required PHMSA to "prescribe regulations on the circumstances under which an operator of a hazardous liquid pipeline facility must use an emergency flow restricting device."

PHMSA never issued a formal analysis on emergency flow restricting device (EFRD) effectiveness. Instead, in its hazardous liquid pipeline integrity management rule, they chose to leave EFRD decisions up to pipeline operators after listing in the rule various criteria for operators to consider. In our opinion such an approach to EFRD use does not appear to meet Congressional intent, partly because the approach is essentially unenforceable and not protective of important environmental assets.

Congress again in the 2011 pipeline safety reauthorization bill asked for a study of such valves and required PHMSA to move forward with regulations to require the use of such valves "where economically, technically, and operationally feasible" based on the findings of the study if they think that such use is "appropriate." Once again, the study is complete, but no regulations have yet been finalized.

For further information:

PHMSA's Pipeline Library

Leak Detection Study and Final Report (Dec 2012): http://www.regulations.gov/#!documentDetail;D=PHMSA-2013-0255-0003

Valve study "Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety" (Oct 2012): https://www.phmsa.dot.gov/technical-resources/pipeline/studies-requirements-automatic-and-remotely-controlled-shutoff-valves