U.S. House of Representatives
Committee on Transportation and Infrastructure
Washington, DC 20515

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July 14, 2010

SUMMARY OF SUBJECT MATTER

TO: Members of the Subcommittee on Railroads, Pipelines, and Hazardous Materials

FROM: Subcommittee on Railroads, Pipelines, and Hazardous Materials Staff

SUBJECT: Hearing on "The Safety of Hazardous Liquid Pipelines (Part 2): Integrity Management"

PURPOSE OF THE HEARING

The Subcommittee on Railroads, Pipelines, and Hazardous Materials is scheduled to meet on Thursday, July 15, 2010, at 10:00 a.m., in room 2167 of the Rayburn House Office Building to receive testimony on pipeline operators' management of the safety of hazardous liquid pipelines, known as integrity management. The hearing is the third in a series of hearings that the Subcommittee will conduct on pipeline safety.

BACKGROUND

According to the Pipeline and Hazardous Material Safety Administration (PHMSA), there are more than 170,000 miles of onshore and offshore hazardous liquid pipelines (about 200 operators) in the United States, which carry more than 75 percent of the nation's crude oil and around 66 percent of its refined petroleum products. Of the more than 170,000 miles of hazardous liquid pipeline, about 55,000 miles are major crude oil trunk lines, which range in diameter from eight inches to 48 inches. Associated with these trunk lines in several locations is significant crude oil tankage, and about 30,000 to 40,000 miles of crude gathering lines, which are smaller lines that gather the oil, gas, and water from many wells, both onshore and offshore, and connect to the larger trunk lines. In addition, there are about 95,000 petroleum product lines, flow lines/piping associated with well operations, and produced water pipelines (containing contaminated water following oil, gas, and water separation). Many hazardous liquid pipelines also transport highly volatile liquid, which is hazardous liquid that will form a vapor cloud when released to the atmosphere.

According to PHMSA, on average over the last five years, there were 349 reportable hazardous liquid pipeline incidents, resulting in two fatalities and four injuries requiring in-patient hospitalization and $131,900,023 in property damage. Although pipeline releases have caused relatively few fatalities in absolute numbers, a single pipeline incident can be catastrophic.

I. MANAGING THE STRUCTURAL INTEGRITY OF HAZARDOUS LIQUID PIPELINES

On February 1, 2000, in the wake of several pipeline ruptures in Bellingham, Washington, Simpsonville, South Carolina, Reston, Virginia, and Edison, New Jersey, PHMSA issued a final rule requiring pipeline operators to evaluate the potential consequences of failure of their pipeline segments that could affect a high consequence area (HCA),[1] and set priorities for inspecting, operating, and maintaining the pipeline based on whether people, property, or the environment might be at risk should a pipeline failure occur.[2] According to PHMSA, pipeline segments that could affect an HCA represent about 44 percent of the total hazardous liquid pipeline mileage in the United States.

Specifically, all hazardous liquid pipelines operators are required to determine which of their pipeline segments could affect HCAs on an ongoing basis. For example, an area that an operator determined did not affect an HCA might subsequently affect an HCA, depending on the circumstances (e.g., new high population or environmentally sensitive areas). After the pipeline segments are identified, the operator is required to comprehensively assess the structural integrity of those pipeline segments that could affect HCAs, using a variety of assessment methods determined appropriate by the operator. Based on these assessments, operators must take prompt action to repair any defects that could reduce a pipeline's integrity. Integrity management assessments must be performed at least once every five years. However, an additional eight months may be added to the reassessment interval to allow for unforeseeable events (e.g., permitting delays, weather events, tool failures) that could affect the ability of the operator to successfully complete an assessment.

As part of the program, PHMSA requires each hazardous liquid pipeline operator to maintain a written integrity management plan at the operators' place of business. Federal regulations specify eight elements that a pipeline operator's integrity management plan must include, but the plan is not submitted to PHMSA for review or approval prior to implementation of the plan (or when a plan is revised).[3] The plans are provided to PHMSA (at PHMSA's request) just prior to each Federal inspection, but they are not maintained by PHMSA because the plans frequently change. According to PHMSA, since 2002, each pipeline operator has been inspected at least one time to review its integrity management program and each major operator has been inspected twice.

In addition to maintaining a written integrity management plan, each operator is required to submit to PHMSA annual performance measure reports,[4] which provide the total miles of each operator's pipelines; the total miles that could affect HCAs; the total volume of product transported in barrel-miles; the total mileage of pipeline assessed by the operator; the total number of anomalies

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[1] HCAs include unusually sensitive environmental areas (defined in 49 C.F.R. 195.6), urbanized areas, and other populated places as delineated by the United States Census Bureau, and commercially navigable waterways.
[2] *See* PHMSA, *Frequently Asked Questions*, http://www.phmsa.dot.gov/about/faq.
[3] 49 C.F.R. § 195.452.
[4] U.S. Department of Transportation, *Implementing Integrity Management for Hazardous Liquid Operators Performance Measure Reports and Quick Facts*, http://primis.phmsa.dot.gov/iim/perfmeasures.htm.

identified as a result of those assessments; and the total number of conditions repaired.[5] Although the reports are publicly available, they provide no information to PHMSA and the public on the actual nature of the anomalies identified by the pipeline operator during the inspections and the conditions that required repair. Safety advocates maintain that more detailed reporting could provide valuable information to PHMSA and the public about the condition of the pipeline and the operating and maintenance practices of the operator.

The first round of operator-performed assessments was completed in February 2009. Pipeline operators reported to PHMSA that they made 31,855 repairs to hazardous liquid pipeline segments that, if left unaddressed, could have affected HCAs. Of those, 6,831 defects were considered to be so serious that immediate repair was required under the regulations; another 25,024 hazardous liquid defects had to be repaired within a 60- to 180-day time period.[6] An example of an immediate repair would be wall loss of more than 80 percent. Certain dents (by size) must be repaired within 60 and 180 days, and 50 percent or more wall loss must be repaired within 180 days.

Safety advocates maintain – particularly given the large number of defects identified as a result of the assessments – that PHMSA should expand the scope of the integrity assessments to require pipeline operators to evaluate the integrity of their pipelines outside of HCAs. Pipeline operators, however, maintain that while they are only required to assess pipelines that could affect HCAs, in practice they evaluate a much greater percentage of pipelines when they conduct these assessments. According to the operators, this is due largely to the practical constraints associated with running in-line inspection tools, such as smart pigs; because of the location of the launchers and receivers used to insert and remove smart pigs from the pipeline, relatively long sections of pipeline are inspected when these tools are used. These sections generally contain portions of the pipeline that can affect HCAs and portions of the pipeline that do not affect HCAs. Thus, while conducting assessments of the portions of their lines that affect HCAs, operators running smart pigs also obtain data on the condition of their pipelines in other areas and take action to assure the integrity of those sections outside of HCAs.

Safety advocates, however, maintain that although larger areas may be assessed, Federal regulations only require operators to repair and report any defects identified that could affect HCAs. If an operator identifies a defect outside of an HCA as a result of those larger assessments, that operator is not required to repair that defect or report it to PHMSA under existing regulations.

II. HOW OPERATORS ASSESS THE INTEGRITY OF THEIR PIPELINES

Federal regulations allow pipeline operators to determine the best method(s) of assessing the structural integrity of their pipelines, using one or more of the following three approaches: in-line

[5] *Id.*
[6] PHMSA, Power Point presentation, *The Pipeline Inspection Program*, prepared upon request of House Transportation and Infrastructure Committee Majority Staff (March 2010).

inspection (ILI), hydrostatic testing, or direct assessment.[7] Alternative assessment methods can be employed if they can be shown to be effective.[8]

ILI, also known as "pigging", is used to detect wall thickness and the amount of corrosion in the line providing the operator with information on operability and safety. Pigs have been an integral part of maintaining pipelines since the beginning of the 20th Century. The earliest devices were basic utility pigs, better known as scraper pigs. Updated versions are still in use today, scraping and scrubbing pipes to remove liquid and solid buildup.[9]

Since 1965, oil pipeline operators have used technologically advanced versions that measure and record problems in the pipes. Known as "smart pigs", these mechanical devices check for potential problems such as corrosion, dents, and cracks, and provide information to a pipeline operator so that corrective measures can be taken.

Smart pigs are cylinder-shaped electronic devices inserted into the pipe and then propelled by the flowing oil. They detect loss of metal or deformations in the pipeline. Pipeline operators use this data to determine where potential problems are, which are then investigated further and repaired as needed.

New technologies have made smart pigs even more efficient and effective. Pigs that use magnetic flux leakage (MFL) technology, ultrasonic measurements, and geometric tools are among the most common smart pigs used today.

There are two types of MFL technologies in use: standard and transverse flux inspection (TFI). TFI operates the same way as standard MFL, except that the magnetic field it generates is turned 90 degrees. Standard MFL pigs are best at detecting cracks and other defects while TFI pigs are better at detecting seam-related corrosion.

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[7] Michael Baker Jr., Inc., *Pipeline Corrosion Final Report*, U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety (November 2008), at 33, http://primis.phmsa.dot.gov/iim/docstr/FinalReport_PipelineCorrosion.pdf.
[8] *Id.* Operators must advise PHMSA 90 days in advance of conducting an assessment with an alternative technology. *See also* PHMSA, *Implementing Integrity Management for Hazardous Liquid Operators: Frequently Asked Questions* (October 15, 2009), at 17, http://primis.phmsa.dot.gov/iim/faqs.htm.
[9] "Utilizing a Smarter Pig," *In the Pipe: News from the Pipeline Industry* (February 2006).

MFL can detect corrosion by sensing magnetic leakage. First, it initiates a magnetic field in the pipeline. If there are any flaws in the pipeline wall, some of the magnetic field will escape. Sensors onboard the pigs detect and measure that leakage. Smart pigs equipped with MFL technology can determine whether the corrosion is internal or external, and they can also measure for changes in the thickness of the walls.

Measurements are made when the pigs emit ultrasonic signals whose echoes are timed and compared with data to determine the wall's thickness. The same ultrasonic technology can detect longitudinal cracks, crack-like defects, and longitudinal weld defects.

Smart pigs can also identify deformations, dents, or obstructions by measuring the bore of the pipe for uniformity. These tools utilize mechanical arms or electro-mechanical instruments.

Pigging has the potential to provide for 100 percent coverage, in contrast to other assessment methods. However, certain larger defects may be missed and defects may not be sized correctly. This is why it is important that each pipeline operator utilize the best assessment tool, and that may require more than one tool.

Hydrostatic testing involves filling a section of pipe with water and increasing the pressure to a level significantly above the normal operating pressure.[10] The primary purpose of hydrostatic testing is to detect and remove joints of the pipeline that contain defects (including corrosion pits or cracks) by causing them to leak or rupture while the pipeline is filled with water.[11]

Direct assessment involves obtaining information from existing records on pipelines, taking measurements of the pipeline, excavating and examining the pipe, and analyzing post-assessment data.[12] Direct assessment is often used for unpiggable pipelines where an interruption of service would be impractical.[13]

III. BACKGROUND ON ALYESKA PIPELINE COMPANY

In 1968, oil was discovered at Prudhoe Bay in the North Slope, located in northern Alaska between the Brooks Range Mountains and the Beaufort Sea (part of the Arctic Ocean). A consortium of oil companies planning to produce the oil determined that a pipeline offered the best means to transport crude oil from the North Slope to a navigable port in southern Alaska where it could be shipped by tanker to refineries in the continental United States. The pipeline route would cover 800 miles from Prudhoe Bay to the port of Valdez, the northernmost ice-free port in the United States.[14]

The Alyeska Pipeline Service Company was established in 1970 and charged with designing, constructing, operating, and maintaining the Trans Alaska Pipeline System, commonly called TAPS. Pipeline construction began in March 1975 and was finished in June 1977. Crude oil began flowing

[10] *Id.* at 35.
[11] *Id.*
[12] *Id.* at 37.
[13] *Id.* at 36.
[14] *See* Alyeska's website at http://www.alyeska-pipe.com.

in the pipeline on June 20, 1977, and the first tanker filled with North Slope crude oil left Valdez on August 1, 1977.[15]

The 48-inch diameter steel pipeline runs 800 miles and crosses three mountain ranges and over 800 rivers or streams; 420 miles of the pipeline is elevated above ground to keep the permafrost from melting. The volume of oil flowing through the pipeline has decreased from a peak of 2.1 million barrels per day (bpd) in 1988 to about 650,000 bpd in 2010. Alaska today supplies nearly 14 percent of the United States' domestic crude oil production.

The consortium of companies that own TAPS today includes:

BP Pipelines (Alaska) Inc.:	46.93 percent
ConocoPhillips Transportation Alaska, Inc.:	28.29 percent
ExxonMobil Pipeline Company:	20.34 percent
Koch Alaska Pipeline Company, LLC:	3.08 percent
Unocal Pipeline Company:	1.36 percent[16]

BP has a strong role in directing Alyeska's operations. Alyeska's president, Kevin Hostler, spent 27 years with BP, most recently as senior vice president of BP's global human resources organization. Before that, Hostler was head of BP's subsidiary in Columbia. According to recent press reports, a top BP Alaska official asked, in light of the Gulf disaster, whether it is a good idea to have Mr. Hostler, a "BP executive", running TAPS, "where BP can exert cultural and economic influence through the president of [Alyeska] as well as its ownership share, in directions that are not good for the safety and the integrity of [the pipeline]." The BP Alaska official said the fact that both companies are plagued by the same safety and management concerns is evidence of a "pervasiveness of a BP leadership culture that is focused on cost cutting that reduces operational integrity." Last Wednesday, one day after the press report surfaced, Alyeska's president resigned, amid allegations that Alyeska – at the direction of BP and Mr. Hostler – was making dangerous cost cuts to the pipeline's integrity management program and falsely inflating the amount of money Alyeska spent on pipeline corrosion.[17] According to Alyeska, Mr. Hostler had already planned to retire at the end of this year.

PHMSA has also been concerned about corrosion in Alyeska's pipelines. In March 2006, internal corrosion on a 34-inch low-stress pipeline, owned by BP Exploration, caused a 5,000 barrel crude oil spill (212,252 gallons spilled) on the North Slope of Alaska. The oil spill was the worst in the history of oil development on Alaska's North Slope, and went undetected for five days before a BP oilfield worker detected the scent of hydrocarbons during a drive through the area. A few months later, in August 2006, a second leak was discovered while BP was inspecting the Eastern Operating Area segment of the pipeline. Field inspection of the leak site revealed multiple holes at a single location, contributing to an estimated spill of about 1,000 gallons of processed crude oil.

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[15] *Id.*

[16] *Id.*

[17] Jason Leopold, "Dangerous Cost Cuts at Alyeska Pipeline: Yet Another Example of How BP Runs Things," *Truthout*, http://www.truth-out.org/alyeska-pipeline-yet-another-example-how-bp-runs-things61097. *See also* Jason Leopold "Alyeska CEO Steps Down Following Truthout Exposé," *Truthout*, http://www.truth-out.org/alyeska-ceo-resigns-following-truthout-expose61134.

During the course of its investigations of the 2006 BP pipeline failures, PHMSA became concerned about the safety of another pipeline (Affected Pipeline) operated by BP and Alyeska because of its shared operating and internal characteristics to the failed BP lines and because the Affected Pipeline had not been cleaned or internally inspected. According to BP, the pipeline is "one of the most important pipelines on the North Slope. The entire flow from the Prudhoe Bay Unit is transported through this pipeline just before it enters the Trans Alaska Pipeline."[18]

Since 2006, PHMSA has – on numerous occasions—urged both BP and Alyeska to comprehensively assess the structural integrity of the Affected Pipeline, repair any defects that were identified, and conduct other work to correct significant corrosion problems or fully replace the pipeline. According to PHMSA, these measures were needed "to protect life, property, and the environment from potential hazards associated with the Affected Pipeline." BP and Alyeska were initially unresponsive to PHMSA's concerns. As a result, on June 20, 2008, PHMSA issued a corrective action order to BP and Alyeska directing them to take immediate action.[19] According to PHMSA, BP and Alyeska now plan to replace the pipeline by the end of this year.

More recently, PHMSA has been focused on a May 25, 2010, incident at Alyeska's Pump Station 9, located near Delta Junction, Alaska. On the morning of May 25, Alyeska briefly shut down the Trans Alaska Pipeline to perform routine maintenance and testing on the fire control system at Pump Station 9 (the site of several previous maintenance failures, including a 2007 fire). Similar maintenance and testing activities had been completed during pipeline slowdowns at other pump stations in early May. During the third and final fire system test procedure at Pump Station 9, which simulated an electrical fire, the station lost power. The redundant power supplies also failed. As a result, Alyeska's operations control center in Anchorage lost visibility to and control of Pump Station 9; meaning, the control center could not see what was happening at the pump station. According to Alyeska's internal investigation report, the station was designed so that a loss of power would cause the station's relief valves to open allowing crude oil to flow into relief tanks so that the pipeline is not inadvertently over pressured. Because of that, crude oil began pumping from the pipeline into an overflow tank, Tank 190. Tank 190 is able to hold 55,000 to 60,000 barrels of oil; prior to the release, it had about 22,000 barrels in it. For a yet-to-be-determined length of time after the pump station lost power, the crude oil filled Tank 190 and then spilled over the top. It was not until the oil spilled over the top that Alyeska personnel who were performing the fire testing observed that crude oil was discharging from the vents on Tank 190 onto the ground.[20] PHMSA estimates that from the time the pump station went "blind" to the control center in Anchorage, about 33,000 barrels (1,386,000 gallons) of oil had filled the tank and another 5,000 barrels (210,000 gallons) spilled onto the ground.

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[18] *See* http://primis.phmsa.dot.gov/comm/reports/enforce/Actions_opid_26149.html.
[19] *Id.*

According to Alyeska, a number of significant incidents on TAPS over the last several years, demonstrate a trend of operational discipline deficiencies similar to those involved with the Tank 190 overfill incident.[21] The report also notes that while the operations command center did not have visibility of Pump Station 9 during the overflow incident, monitoring upstream pressure at Pump Station 8 would have provided insight to the controllers that pipeline pressure was dropping, indicating flow to Pump Station 9.

After evaluating the facts surrounding the incident, PHMSA's Associate Administrator for Pipeline Safety issued a corrective action order to Alyeska stating, "I find that the operation of TAPS [the Trans Alaska Pipeline System] without corrective action measures would be hazardous to life, property and the environment." According to PHMSA:

> Additionally, after considering the age of the pipeline facility, the particular circumstances surrounding this failure and crude oil spill, the failure to actuate certain valves around the time of the spill, suspected problems with the electrical power system, the proximity of the pipeline and breakout tank to an HCA, the hazardous nature of the crude oil being transported, the pressure required for transporting the material when the line is operational, Alyeska's intention to restart the pipeline without the relief capacity provided by Tank 190, the uncertainties as to the cause of the failure, and the ongoing investigation to determine the cause of the failure, I find that a failure to issue this order expeditiously to require immediate corrective action would result in likely serious harm to life, property, and the environment.[22]

The corrective action order required Alyeska to implement a variety of safety measures, including locating personnel at the pump station around the clock to monitor activities.[23] Alyeska is in the process of removing personnel from its pump stations along the 800-mile pipeline, as part of its Strategic Reconfiguration plan that, according to Alyeska, concentrates on reducing physical

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[21] These significant incidents include a tank vent fire at Pump Station 9 on January 6, 2007; a Remote Gate Valve leak on January 9, 2007; an overfill near loss of Tank 190 at Pump Station 9 on March 22, 2007; energy isolation near loss events at Pump Station 9 in October 2008; Sadelrochit Stream Gas Excursion at Pump Station 1 on January 15, 2009; and a pipeline overpressure event at Pump Station 9 on July 19, 2009. *See also* Alyeska Pipeline Service Company, *TK190 Overfill Incident Root Cause Analysis Report and Post Accident Review* (June 22, 2010).
[22] *Id.*
[23] *Id.*

infrastructure and simplifying operations and maintenance. The plan calls for electrification of pump stations and installation of new control systems for the pipeline. After reconfiguration, each pump station will be manned from Alyeska's operations control center in Anchorage. According to Alyeska's prior president, David Wight, who also served as President of BP Amoco Energy Company: "When we are done, Strategic Reconfiguration will shave millions of dollars from the annual cost of moving oil from Prudhoe Bay to Valdez. Our workers still face many challenges as we modernize the pipeline. However, I am confident that they will succeed in extending TAPS' economic life while maintaining the highest safety, integrity and environmental standards."

In addition to the two corrective action orders, PHMSA has issued 13 notices of probable violation to Alyeska since 2002 alleging violation of various Federal regulations, including significant deficiencies in Alyeska's integrity management and corrosion control programs; 10 notices of amendment, which identify shortcomings in Alyeska's plans and procedures under PHMSA regulations; and 10 warning letters regarding deficiencies in Alyeska's programs. PHMSA has proposed a total of $1,754,300 in civil penalties as a result of the alleged failures.

One of the most recent violations was for what PHMSA characterizes as a "near miss incident" in January 2010. BP was using natural gas to push a cleaning pig through its pipeline (an abnormal and potentially dangerous operation). Two breakout tanks at Alyeska's Pump Station 1 were over pressurized due to the rapid influx of natural gas into TAPS, which caused Alyeska's tanks' relief vents and "blow out" type hatches to open and release flammable vapors. Following the incident, Alyeska restarted the pipeline without verifying and confirming system integrity. According to the corrective action order, Alyeska didn't even conduct a visual inspection of the tanks before restarting the system.[24] Alyeska is challenging the proposed violation.

IV. Background on Enbridge – U.S. Operations

Enbridge Pipelines Inc. operates the world's longest and most sophisticated crude oil and petroleum products pipeline system. The 1,900-mile Lakehead System (the U.S. portion of the world's longest pipeline) has operating for 59 years and is the primary transporter of crude oil from Western Canada to the United States. The system spans from the international border near Neche, North Dakota, to the international border near Marysville, Michigan, with an extension across the Niagara River into the Buffalo, New York area. It consists of approximately 3,500 miles of pipe with diameters ranging from 12 to 48 inches; 60 pump station locations; and 64 crude oil storage tanks with a capacity of about 11.6 million barrels. Total deliveries on the Lakehead System averaged 1.62 million bpd in 2008, meeting approximately 72 percent of Minnesota refinery capacity; 64 percent of the greater Chicago area; and 68 percent of Ontario's refinery demand.

Enbridge's North Dakota System is a 330-mile crude oil gathering and 620-mile interstate transportation system that gathers crude oil from points near producing wells in 22 oil fields in North Dakota and Montana. Most deliveries from the approximately 161,000 bpd North Dakota System are made at Clearbrook, Minnesota, which provides connections with the Lakehead System and a third-party pipeline that transports crude oil to refineries in the Minneapolis/St. Paul area.

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[24] *Id.*

In response to increasing crude oil production in the region, Enbridge recently completed a 51,000 bpd expansion in early 2010. Enbridge is proposing additional expansions of the North Dakota System.

The Enbridge Toledo Pipeline connects to the Lakehead System at Stockbridge, Michigan, and travels southward to two refineries in the Toledo, Ohio, area. This 35-mile pipeline has a capacity of 100,000 barrels per day in heavy crude oil service and became available for service in February 1999.

The first continuous delivery of western Canadian crude oil was initiated in early March 2006 through Enbridge's Spearhead Pipeline to Cushing, Oklahoma. The 650-mile, 22- and 24-inch diameter pipeline historically operated in south-to-north service, but Enbridge bought the pipeline and reversed its flow to provide Canadian crude oil producers and shippers with access to markets in the Mid-Continent and southern United States. Enbridge recently expanded the Spearhead Pipeline, increasing the average annual capacity from 125,000 bpd to 190,000 bpd.

The Mid-Continent System comprises the Ozark and West Tulsa pipelines and storage terminals at Cushing, Oklahoma, and El Dorado, Kansas. The Mid-Continent System includes more than 480 miles of crude oil pipelines, with average deliveries in 2008 totaling 231,000 bpd. It has 96 individual storage tanks ranging in size from 55,000 to 575,000 barrels. A recent expansion of the Cushing Terminal increased storage capacity on the system to 16 million barrels.

In addition to Enbridge's many wholly owned pipelines and facilities, the company has interest in several other liquids pipelines across the United States.[25]

PHMSA reports that, since 2002, it has issued one corrective action letter and one proposed corrective action letter to Enbridge. The most recent corrective action letters stems from a pipeline rupture that occurred on January 8, 2010, resulting in the release of about 3,000 barrels (126,000 gallons spilled) of crude oil near Neche, North Dakota. PHMSA found that continued operation of the line without corrective action measures, including a mandatory reduction in pressure on the pipeline stemming from the Canadian border to Superior, Wisconsin, would be hazardous to life, property, and the environment.

PHMSA proposed another corrective action order (and $2,405,000 in civil penalties) to Enbridge stemming from a fatal accident that occurred on a 34-inch crude oil pipeline on November 28, 2007, near Clearbrook, Minnesota.[26] The oil spill started with a leak the size of a pinhole, and erupted into an explosion and towering flames, killing two Enbridge workers and resulting in more than $2 million in property damage.

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[25] *See* Enbridge Pipeline's Internet web site at http://www.enbridgeus.com/.
[26] *See* http://primis.phmsa.dot.gov/comm/reports/enforce/Actions_opid_26149.html.

PHMSA found that Enbridge failed to: (1) follow its written procedures regarding welds+ends couplings used by its field personnel for pipeline replacement; (2) ensure that the pipeline was sufficiently anchored before installing the couplings; review the work performed by its personnel; (3) remove multiple ignition sources around the area the work was being performed; and (4) ensure that personnel received proper training and were qualified to conduct the repairs. PHMSA also found that Enbridge had operated the pipeline in excess of the design pressure of the weld+ends couplings as determined by the manufacturer and outlined in its recommended installation instructions.[27]

In addition to the $2,405,000 in civil penalties proposed as a result of the Clearbrook, Minnesota incident, PHMSA has proposed $121,500 in civil penalties for various violations since 2002, including the failure of Enbridge to conduct certain inspections and maintain certain records. PHMSA has also issued six notices of amendment, which identify shortcomings in Enbridge's plans and procedures under PHMSA regulations; and seven warning letters regarding deficiencies in Enbridge's programs.[28]

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27 *See* http://primis.phmsa.dot.gov/comm/reports/enforce/Actions_opid_26149.html.
28 *Id.*

<u>Witnesses</u>

Mr. Richard Adams
Vice President, U.S. Operations, Liquids Pipelines
Enbridge Pipelines

The Honorable David Guttenberg
House District 08 – Fairbanks, Alaska
Alaska State House Minority Whip

Mr. Greg Jones
Senior Vice President, Technical Support Division
Alyeska Pipeline Service Company

Mr. Richard Kuprewicz
Public Member, PHMSA's Technical Hazardous Liquid Pipeline Safety Standards Committee

The Honorable Cynthia Quarterman
Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation