Exhibit 1

Part 2 Comments 8 - 11

Comment 8

D. J. Ref. No. 90-5-1-1-10099

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Via email: pubcomment-ees.enrd@usdoj.gov

RE: Notice of Lodging of Proposed Consent Decree Under the Clean Water Act and the Oil Pollution Act in the lawsuit entitled *United States v. Enbridge Energy, Limited Partnership, et al., D.J. Ref. No. 90-5-1-1-10099*, 1:16-cv-00914 ECF No. 1 (Complaint), 1:16-cv-00914 ECF No. 3 (Consent)

Assistant Attorney General, DOJ - ENRD:

These comments are submitted on behalf of the primary authors – Southeast Environmental Task Force, Dunelands Environmental Justice Alliance, Southeast Side Coalition to Ban Petcoke, 350 Indiana, 350Kishwaukee, Break Free Midwest Response Network, and ALERT, a project of Earth Island Institute–as well as all of the supporting signatories.

Southeast Environmental Task Force (SE Task Force) is a Chicago-based 501(c)3 organization dedicated to serving the southeast side of Chicago. SETF formed in 1989 by Marian Byrnes as a coalition of 30 grassroots organizations working to promote sustainable development, environmental restoration and justice, and pollution prevention.

Dunelands Environmental Justice Alliance (DEJA) is an anti-racist, multiracial coalition of grassroots organizations in the Calumet industrial corridor of Northwest Indiana fighting for a healthy environment in communities of color.

Southeast Side Coalition to Ban Petcoke (SSCBP) is a multicultural group of Chicago area residents, families, and community-based environmental and social justice organizations working together to rid the community of petroleum coke, a toxic byproduct of the oil refining process. As one of the largest and oldest industrial regions in the world, we are working together to raise our voices in a fight for a just transition to a cleaner future that benefits our community and the region.

350 Indiana, based in East Chicago, Indiana is diverse group of people creatively bringing awareness and finding solutions to climate change.

350Kishwaukee is a 501(c)3 nonprofit corporation, based in DeKalb, Illinois, and representing citizens from throughout the Great Lakes region seeking to reduce pollution in our land, water, and air.

Break Free Midwest Response Network is a coalition of organizations in the U.S Midwest that are seeking a just transition to a low-carbon future in response to the threats of Climate Change.

ALERT, a project of Earth Island Institute was founded by *Exxon Valdez* oil spill survivor Dr. Riki Ott in 2014 to make healthy people and healthy communities part of our energy future. ALERT works in local communities nationwide, sharing science and skills to empower people impacted by oil and chemical activities to have a meaningful voice in determining what activities occur in their region.

I. OUR STATEMENT & ASKS

A. Overview

Our Commons[1] *- our water supply, the land we inhabit, the air we all breathe - is a priceless and irreplaceable resource. Present generations are responsible for maintaining the health and wellbeing of this Commons*[2] *for future generations. By the people's consent, this responsibility is entrusted as a duty to all governments – local, state, and federal. Ensuring the viability and health of our public and privately owned land, our community water supply and the air we breathe should be at the highest level of concern for all community leaders - publicly elected leaders and leaders of privately owned corporations who mutually benefit from our Commons. Past and present operations of the Enbridge Corporation jeopardize this goal. It is our firm belief that business-as-usual practices cannot continue without serious and irreparable harm befalling our precious resources of land, water and air. Recognizing historically recurring errors is the first step to our moving forward to protect our Commons from all and any entity that feels they have a right to pollute to make a profit that values profits over people and disavows any responsibility to maintain the health of our mutual Commons.*

Among large multinational industrial companies operating in the United States, Enbridge Corporation has one of the worst records of environmental violations. The record shows that Enbridge Corporation and their affiliated companies are risk takers with a repeated pattern of cutting costs to increase profits. The record shows that the costs of this risk behavior are human lives, the environment, and the health and well-being of people living in communities near Enbridge pipelines and related infrastructure. The occasional million dollar civil or criminal penalties and fines have not served to change Enbridge Corporation's cultural risk-prone mindset or deter environmentally risky business decisions. Historically, the spills and leaks endured by our communities at the hand of this careless energy giant are very much a repeat of previous spills and leaks. At what point will this be addressed? We suggest now is the time to start.

This proposed settlement agreement follows the same pattern as previous settlements by requiring more technology and more internal company monitoring and inspections. This is just more of the same fox guarding the same henhouse, and it will produce the same results – more self-reported or unreported pollution discharges into our land, water supplies, and air from daily operations, more oil and chemical spills, further weakening of industry-government vigilance, and declining environmental and social standards. This proposed settlement and its token agreements provide us with no sense of relief or confidence that the operations at the Enbridge Corporation will be any safer. We want and deserve more. Enbridge has consistently shown a shocking lack of responsibility in maintaining pipeline infrastructure under its control and thereby has shown their failure to responsibly ensure the Commons as outlined below:

a. Beginning July 25, 2010, at least **20,082 barrels** of diluted bitumen, derived from Canadian "tar sands" with a hydrocarbon diluent, which includes benzene, a hazardous air pollutant, was unlawfully discharged into waters near Marshall, Michigan from the oil transmission pipeline known as Line 6B, which eventually reached and polluted Talmadge Creek and the Kalamazoo

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[1] *What, Really, is the Commons?*, Terrain.org: A Journal of the Built + Natural Environments http://www.terrain.org/articles/27/walljasper.htm

[2] *Concept Of Tragedy Of The Commons; Issues And Applications,* By Charles C. Anukwonke, https://www.researchgate.net/publication/277708953_The_Concept_of_Tragedy_of_the_Commons_Issues_and_Applications

River, Morrow Lake, adjacent wetlands, and adjoining shorelines.[3] "The oil impacted over 1,560 acres of stream and river habitat as well as floodplain and upland areas, injuring birds, mammals, reptiles and other wildlife"[4]

b. On September 9, 2010, Enbridge Line 6A discharged least **6,427 barrels** of Smilely Coleville crude oil into the environment from a 2.25 inch hole in the pipeline in Romeoville, Illinois. Much of the discharged oil entered the sanitary and storm drain systems including a storm water management pond, and the waste water treatment plant. The spill killed and injured various wildlife species.[5]

c. Enbridge has a history of not responding to landowner concerns and complaints, a history currently demonstrated by landowner concerns about the abandonment of its Line 3. Landowners warn that "as it corrodes, the pipe will eventually become a water conduit that could easily drain a wetland or small lake, or flood a farm field."[6] Will Enbridge, or regulators, respond to protect the Commons? Another example documents landowner complaints about a new Enbridge pipeline, Line 61. In 2014, the LaSalle County Farm Bureau documented the failure of Enbridge to respond to landowner concerns about soil and water problems in a survey. The resulting well-documented reports showed, inter alia, that five years after the construction of Line 61, 94% of the landowners had problems and "[o]nly 21% of those problems have been resolved, the other 79% of respondents with problems still have problems." [7]

B. Asks

In the following comments, we provide proof of the need for each of our requests: for maximum penalties for all violations; for three additional conditions under this settlement; and for a neutral third party fiduciary recipient of funds from penalties and settlement conditions. We summarize our requests below.

Sec. II. Maximum fines must be assessed for all violations listed in the proposed Consent Decree, based on Enbridge's repeated pattern of reckless, negligent, and/or grossly negligent behavior relating oil spill prevention and response planning, behavior that has been previously undeterred by million dollar fines.

Sec. III. Additional conditions under this settlement:

A. Establishment of two (2) independent citizen groups:

Lake Michigan Regional Citizens' Advisory Council (RCAC) with key stakeholder groups, modeled after the Prince William Sound RCAC established under the Oil Pollution Act of 1990, and $10 million annually, inflation-proofed, for program implementation;

Upper Mississippi Regional Citizens' Advisory Council (RCAC) with key stakeholder groups, modeled after the Prince William Sound RCAC established under the Oil Pollution Act of 1990, and $10 million annually, inflation-proofed, for program implementation;

[3] Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations, NTSB, http://www.ntsb.gov/news/press-releases/Pages/PR20120710.aspx

[4] Enbridge Must Restore Environment Injured by 2010 Kalamazoo River Oil Spill, U.S. Fish and Wildlife Service, https://www.fws.gov/midwest/news/785.html

[5] See Exhibit #1

[6] *Line 3 Pipeline Abandonment*, Minnesotans for Pipeline Cleanup. August 2016, http://pipelinecleanupmn.org/sites/default/files/2016-08/factsheet-MPC-Abandonment-08-2016%20.pdf

[7] See Exhibit #2

B. Establishment of two (2) independent municipal-focused committees:

Lake Michigan Area Committee comprised of local, state, and federal agencies, as mandated under the Oil Pollution Act of 1990, and $10 million annually, inflation-proofed, for program implementation;

Upper Mississippi Area Committee comprised of local, state, and federal agencies, as mandated under the Oil Pollution Act of 1990, and $10 million annually, inflation-proofed, for program implementation;

C. Establishment of an **Independent Environmental Monitoring Program** for the Enbridge pipeline infrastructure, modeled after the environmental monitoring program conducted by the Prince William Sound RCAC for the Alyeska tanker terminal;

Sec. IV. A neutral third-party fiduciary recipient such as the National Fish and Wildlife Foundation of *all penalties and funds* resulting from this Consent Decree and settlement agreement for funding for local and/or regional citizens' advisory projects at the same levels and with the same goals of the organizational structures defined in the conditions set forth in Section III.

C. Spill Data

This section provides support for our Asks. Table 1 summarizes the Enbridge spill history in the US and Canada from 1996 through 2014 of well over 1000 spills and approaching one billion gallons. A *partial* list of major spills follows Table 1 illustrating a track record of pervasive, systemic environmental and safety issues. The data in Table 1 and the accompanying *partial* list support our charges of repeated willful, reckless behavior, negligence, and gross negligence on the part of Enbridge.

Enbridge Liquids Spills in Canada and United States			
Year	**Number of Spills**	**Quantity in Barrels**	**Quantity in US Gallons**
1996	49	13,698	575,316
1997	47	19,853	833,826
1998	39	9,830	412,860
1999	54	28,760	1,207,920
2000	48	7,513	315,546
2001	33	25,980	1,091,160
2002	48	14,683	616,686
2003	62	6,410	269,220
2004	69	3,252	136,584
2005	70	9,825	412,650
2006	61	5,663	237,846
2007	65	13,777	578,634
2008	80	2,682	112,644

2009	103	8,441	354,522
2010	91	34,258	1,438,836
2011	58	2,284	95,928
2012	85	10,224	429,408
2013	114	4,298	180,516
2014	100	2,943	123,606
Total	1,276	224,374	9,423,708
Data compiled from Enbridge websites Archived data available on request			

Track Record of Environmental & Safety Issues, Spills for Enbridge

2000: A spill of 1,500 barrels of crude oil Near Innes, Saskatchewan on the Enbridge (Saskatchewan) System. More than 2,000 tons of contaminated soil were removed for off-site disposal.[8]

2000: In Northwest Minnesota 50 barrels of crude oil were released oil on the Lakehead System into wetlands in a remote area.[8]

2000: At the Superior Terminal in the Lakehead System 1,200 barrels were released on company property.[8]

January 17, 2001: In Hardisty, Alberta approximately 23,900 barrels of crude oil were released on land and a nearby slough after a seam failure on the Energy Transportation North pipeline near the Hardisty Terminal.[8]

February 13, 2001: In Satartia, Mississippi approximately 100 barrels of crude oil were released from the Enbridge Pipelines (Midla) Inc.'s Tinsley System.[8]

September 3, 2001: In Fairbanks, Louisiana approximately 7 million cubic feet of natural gas and 428 barrels of an oily mixture were released from the Enbridge Pipelines (Midla) System. Contaminated liquids were removed.[8]

September 29, 2001: In Binbrook, Ontario approximately 598 barrels of crude oil were released from the Energy Transportation North System.[8]

January 18, 2002: In Kerrobert, Saskatchewan approximately 6,133 barrels of crude oil were released from a leaking gasket on the Energy Transportation North pipeline at the Kerrobert Station.[8]

May 8, 2002: In Glenboro, Manitoba approximately 598 barrels of crude oil were released onto agricultural land after a seam failure on the Energy Transportation North pipeline.[8]

July 4, 2002: July 2002: A 34-inch-diameter pipeline owned by its affiliate Enbridge Energy Partners ruptured in a marsh near the town of Cohasset, Minnesota, contaminating five acres of wetland spilling 6,000 barrels of crude oil. In an attempt to keep the oil from contaminating the Mississippi River, the

[8] These data from Enbridge websites are no longer available on-line. Archived website data is on file with 350Kishwaukee and is available on request.

Minnesota Department of Natural Resources set a controlled burn that lasted for one day and created a smoke plume about 1-mile (1.6 km) high and 5 miles (8.0 km) long.[8 9]

January 24, 2003: Approximately 4,500 barrels of crude oil spilled from the Lakehead System at the Enbridge Terminal near Superior, Wisconsin. The leak was caused by a failure in a section of terminal pipe during oil delivery from the pipe to a storage tank. About 500 barrels breached the terminal's containment system and flowed off site onto the nearby Nemadji River, a tributary of Lake Superior. The ground and river were frozen at the time, helping to prevent spread of the oil into soils or downstream.[8 10]

2004: The U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) proposed a fine of $11,500 against Enbridge Energy for safety violations found during inspections of pipelines in Illinois, Indiana and Michigan. The penalty was later reduced to $5,000. In a parallel case involving Enbridge Pipelines operations in Minnesota, an initial penalty of $30,000 was revised to $25,000.[11]

February 22, 2004: Approximately 1,635 barrels of crude oil were released when a valve failed on the Athabasca pipeline system. Approximately 735 barrels of free product and contaminated debris were recovered.[8]

February 19, 2004: In Grand Rapids, Michigan, during a maintenance dig on the Lakehead System, crews discovered a slow leak of crude oil, caused by a dent resulting from the pipe lying on a rock. Soil excavations and groundwater monitoring wells revealed contaminated soil and groundwater and the loss of about 1,000 barrels of crude oil.[8]

2005: Liquids Pipelines recorded 70 reportable liquid spills totaling 9,825 barrels from Enbridge pipelines in Canada and the United States.[8]

March 18, 2006: In Willmar, Saskatchewan an estimated 613 barrels of crude oil were released when a pump failed at Enbridge Pipelines (Saskatchewan) Inc.'s Willmar Terminal. According to Enbridge, roughly half the oil was recovered.[8]

December 22, 2006: In Sheridan County, Montana approximately 2,000 barrels of oil were released when a two-inch nipple failed downstream of a pump at a lease site on our North Dakota System in Sheridan County, Montana. The released oil gathered in a low spot in a pasture approximately 150 yards from the pump.[8]

January 1, 2007: An Enbridge pipeline in Clark County that runs from Superior, Wisconsin to near Whitewater, Wisconsin cracked open and spilled 1,250 barrels of crude oil onto farmland and into a drainage ditch.[8 12]

February 2, 2007: Construction crews struck an Enbridge pipeline, near Exeland in Rusk County, Wisconsin, spilling 3,000 barrels of crude. Some of the oil filled a hole more than 20 feet deep and contaminated the local water table.[8]

[9] Enbridge - Spills and Violations, http://www.liquisearch.com/enbridge/spills_and_violations

[10] Intercontinental Cry https://intercontinentalcry.org/occupy-enbridge-taking-a-stand-on-red-lake-sovereign-land/

[11] Enbridge: Corporate Rap Sheet, Corporate Research Project http://www.corp-research.org/enbridge

[12] Oil spill tainted water table, The Milwaukee Journal Sentinel, http://archive.jsonline.com/news/wisconsin/29343664.html

April 2007: Approximately 6,227 barrels of crude oil spilled in a field downstream of Liquids Pipelines' pumping station at Glenavon, Saskatchewan. The line is a 34-inch, 490,000 barrel-per-day line transporting heavy and medium crude oil from Edmonton, Alberta, to Superior, Wisconsin.[8]

November 28, 2007: A spill occurred on Enbridge Line 3 in Clearbrook, Minnesota resulting in an explosion. "The accident happened when Enbridge attempted to complete a repair of a longitudinal seam leak by installing a new 11-foot section of pipe. One of the couplings used to join the new section of pipe slipped during restart of the line, allowing the release of crude oil that formed a flammable cloud. An open flame heater positioned at the edge of the excavation ignited the cloud resulting in a fire that caused the deaths of two Enbridge employees as well as property damage to the pipeline and construction equipment." The PHMSA later fined the company $2,405,000 for safety violations connected to the incident.[13]

2008: The Wisconsin Department of Natural Resources charged Enbridge with more than 100 environmental violations relating to the construction of the Line 61 pipeline across much of the state. "Pipeline construction was plagued by problems, including illegal harm to wetlands and streambeds and failure to control erosion next to waterways." "The case was settled for a record $1.1 million in fines and mandated reclamation work."[14]

January 23, 2008: Approximately 629 barrels of crude oil were released when a flange gasket on a Line 4 pump unit at Cromer Terminal failed near Cromer, Manitoba.[8]

February 23, 2008: Approximately 157 barrels of crude oil were released at the Weyburn Truck Terminal facility when a drainage line from a receiving trap to an underground sump tank was mistakenly left open causing the sump tank to overflow onto the facility property near Weyburn, Saskatchewan.[8]

March 29, 2008: Approximately 252 barrels of crude oil were released when a drain line on a meter manifold at Athabasca Terminal failed near Fort McMurray, Alberta.[8]

April 6, 2008: Approximately 550 barrels of crude oil were released from a small corrosion hole in the floor of a storage tank at Enbridge's Eldorado Terminal near Eldorado, Kansas.[8]

April 15, 2008: approximately 260 barrels of crude oil were released when a thermal relief line on Tank 79 at Griffith Terminal was broken by a swing stage during tank painting operations near Griffith, Indiana.[8]

July 6, 2008: Approximately 252 barrels of crude oil were released from Tank 25 at Edmonton Terminal when a nitrogen purge from a third-party feeder pipeline following a delivery caused oil to flow onto the roof near Edmonton, Alberta.[8]

January 3, 2009: A leak occurred near Cheecham, Alberta at Enbridge Athabasca's Cheecham Terminal where approximately 5,749 barrels of oil was released when a three-quarter-inch nipple connected to a vent valve failed on a vertical expansion loop. The leak resulted in oil spraying vertically from the connection, covering a considerable area of the terminal and associated facilities

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[13] See Exhibit #3

[14] Oil & Water: Pipeline To Triple Flows Under St. Croix Headwaters, St. Croix 360 http://www.stcroix360.com/2014/10/oil-water-pipeline-to-triple-flows-under-st-croix-headwaters/

with oil. Most free product was contained on-site, but an oil mist was also blown off-site, contaminating an area of approximately 450 meters by 1,500 meters downwind of the facility.[8]

February 9, 2009: Approximately 704 barrels of oil was released near Kisbey, Saskatchewan from the Liquids Pipelines Saskatchewan system into a field in southeastern Saskatchewan.[8]

June 2, 2009: PHMSA assessed a civil penalty of $105,000 against Enbridge Pipelines LLC-North Dakota for a January 25, 2007 accident that released 9,030 gallons of crude oil gallons of crude oil 9,030. The accident occurred on January 25, 2007, at the company's Stanley Pump Station[15]

January 8, 2010: Approximately 3,748 barrels of synthetic crude oil was released from Line 2B at milepost 774.18, just across the international border downstream from the Gretna (Manitoba) Station near Neche, North Dakota.[8]

February 25, 2010: A release of crude oil occurred at a broken nipple on the drain valve of a booster pump at Enbridge's Edmonton, Alberta, terminal. Approximately 818 barrels of diluent was released into a concrete containment pit. [8]

On April 1, 2010: Just southwest of the town of Virden, Manitoba, 16 barrels of crude oil were released from a 6-inch Enbridge Pipelines (Virden) Inc. pipeline into the creek bed of Bosshill Creek, causing an oily sheen to form in a portion of the creek. [8]

June 22, 2010: A release of crude oil occurred due to an o-ring seal failure at the Line 4 sending trap located at Enbridge's Cactus Lake, Saskatchewan, pump station. Approximately 157 barrels of crude oil was released onsite. The crude oil was found in the area of the sending trap, drainage ditch and on the surface of the storm water pond.[8]

On July 26, 2010: A release of crude oil on Line 6B of Enbridge Energy Partners, L.P.'s (EEP) subsidiary's Lakehead system was reported near Marshall, Michigan.[8] On 7/10/2012 the National Transportation Safety Board posted the following press release:[16]

> *WASHINGTON - Pervasive organizational failures by a pipeline operator along with weak federal regulations led to a pipeline rupture and subsequent oil spill in 2010, the National Transportation Safety Board said today.*
>
> *On Sunday, July 25, 2010, at about 5:58 p.m., a 30 inch-diameter pipeline (Line 6B) owned and operated by Enbridge Incorporated ruptured and spilled crude oil into an ecologically sensitive area near the Kalamazoo River in Marshall, Mich., for 17 hours until a local utility worker discovered the oil and contacted Enbridge to report the rupture.*
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> *The NTSB found that the material failure of the pipeline was the result of multiple small corrosion-fatigue cracks that over time grew in size and linked together, creating a gaping breach in the pipe measuring over 80 inches long.*

[15] Pipeline and Hazardous Materials Safety Administration, Final Order: CPF No. 3-2007-5022 http://primis.phmsa.dot.gov/Comm/Reports/enforce/documents/320075022/320075022_FinalOrder_06022009_text.pdf

[16] Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations, NTSB, http://www.ntsb.gov/news/press-releases/Pages/PR20120710.aspx

"This investigation identified a complete breakdown of safety at Enbridge. Their employees performed like Keystone Kops and failed to recognize their pipeline had ruptured and continued to pump crude into the environment," said NTSB Chairman Deborah A.P. Hersman. "Despite multiple alarms and a loss of pressure in the pipeline, for more than 17 hours and through three shifts they failed to follow their own shutdown procedures."

Clean up costs are estimated by Enbridge and the EPA at $800 million and counting, making the Marshall rupture the single most expensive on-shore spill in US history.

Over 840,000 gallons of crude oil - enough to fill 120 tanker trucks - spilled into hundreds of acres of Michigan wetlands, fouling a creek and a river. A Michigan Department of Community Health study concluded that over 300 individuals suffered adverse health effects related to benzene exposure, a toxic component of crude oil.

Line 6B had been scheduled for a routine shutdown at the time of the rupture to accommodate changing delivery schedules. Following the shutdown, operators in the Enbridge control room in Edmonton, Alberta, received multiple alarms indicating a problem with low pressure in the pipeline, which were dismissed as being caused by factors other than a rupture. "Inadequate training of control center personnel" was cited as contributing to the accident.

The investigation found that Enbridge failed to accurately assess the structural integrity of the pipeline, including correctly analyzing cracks that required repair. The NTSB characterized Enbridge's control room operations, leak detection, and environmental response as deficient, and described the event as an "organizational accident."

Following the first alarm, Enbridge controllers restarted Line 6B twice, pumping an additional 683,000 gallons of crude oil, or 81 percent of the total amount spilled, through the ruptured pipeline. The NTSB determined that if Enbridge's own procedures had been followed during the initial phases of the accident, the magnitude of the spill would have been significantly reduced. Further, the NTSB attributed systemic flaws in operational decision-making to a "culture of deviance," which concluded that personnel had a developed an operating culture in which not adhering to approved procedures and protocols was normalized.

The NTSB also cited the Pipeline and Hazardous Materials Safety Administration's weak regulations regarding pipeline assessment and repair criteria as well as a cursory review of Enbridge's oil spill response plan as contributing to the magnitude of the accident.

The investigation revealed that the cracks in Line 6B that ultimately ruptured were detected by Enbridge in 2005 but were not repaired. A further examination of records revealed that Enbridge's crack assessment process was inadequate, increasing the risk of a rupture.

"This accident is a wake-up call to the industry, the regulator, and the public. Enbridge knew for years that this section of the pipeline was vulnerable yet they didn't act on that information," said Chairman Hersman. ***"Likewise, for the regulator to delegate too much authority to the regulated to assess their own system risks and correct them is tantamount to the fox guarding the hen house. Regulators need regulations and practices with teeth, and the resources to enable them to take corrective action before a spill. Not just after."***

As a result of the investigation, the NTSB reiterated one recommendation to PHMSA and issued 19 new safety recommendations to the Department of the Transportation, PHMSA, *Enbridge Incorporated, the American Petroleum Institute, the International Association of Fire Chiefs, and the National Emergency Number Association.*

July 29, 2010: A leaking flange was discovered on Line 2 at the North Cass Lake, Minnesota, Station. Released crude oil was collected and approximately 200 cubic meters of impacted soil was removed. While the initial volume estimate of the leak was several barrels of oil, a low water table at the site allowed oil to travel downward and away from detection. Reassessment of the release, through the installation of additional monitoring wells, now estimates that oil was leaking for some time and as much as 1,500 barrels of oil is present on the groundwater table, extending both on and off Enbridge's property.[8]

September 9, 2010: A crude oil release from Line 6A of Enbridge Energy, Limited Partnership's Lakehead System was reported in Romeoville, Illinois.[8] The National Transportation Safety Board (NTSB) reported that the 34" pipeline "leaked beneath the street pavement […] releasing about 6,430 barrels of Saskatchewan heavy crude oil", and that the "[d]amages, including the cost of the environmental remediation, totaled about $46.6 million."[17] "The closest residential areas were about 200 yards from the spill site, which was also within populated and ecologically sensitive areas designated as high consequence areas in Title 49 Code of Federal Regulations (CFR) 195.450." [17]

Enbridge reported that the monitoring system showed no indication of a leak during the several hours before discovering the crude oil release. At 9:36 a.m. on September 9, 2010, a passerby reported a water leak near 717 Parkwood Avenue to the Romeoville Public Works Department (PWD). The PWD immediately dispatched an equipment operator to investigate the water leak. At 9:46 a.m., the equipment operator notified the PWD water superintendent that water was discharging from expansion joints and cracks in the pavement from what he believed was a leaking service line. The equipment operator closed a valve on the water service line to Northfield Block Company, a privately owned business near the leak site, stopping the water discharge. Concluding that the leak was not creating a safety hazard, he turned the valve back on to restore water service to the facility—the water flow resumed from cracks in the pavement. He recommended a water leak detection company to a Northfield Block Company representative.

About 11:30 a.m., a technician from Water Services, Inc., the water leak detection company hired by Northfield Block Company, arrived at the scene to locate the source of the leak. In addition to the leaking water, the technician observed oil discharging from beneath the pavement in the vicinity of the reported water leak.

At 12:04 p.m., the Romeoville Fire Department received a report about a gas-like odor at 719 Parkwood Avenue, the location where oil was flowing out of the ground. Firefighters were dispatched to conduct an outdoor gas odor investigation. Upon their arrival at 12:11 p.m., they observed black oil discharging from expansion joints and cracks in a 30 square foot area of an asphalt-and-concrete driveway at the entrance to the Northfield Block Company. They describe a heavy flow of oil running south along the street gutter in a 4-foot wide stream that was about 6 inches deep (see figure 1). The fire department immediately notified Enbridge, and a control center operator initiated the oil pipeline shutdown at 12:29 p.m.

[17] See Exhibit #1

> *The released oil flowed into a storm water drainage ditch and then to a storm water management pond. Both required subsequent excavation and restoration activities to remove the oil.*
>
> *Three days later, Enbridge crews excavated the area around the damaged water and crude of pipelines. Investigators observed a 1.5-inch diameter hole on the underside of the oil pipeline directly above the leaking 6-inch diameter water pipe that crossed 5 inches beneath the Enbridge pipeline. The earthen material around the pipes contained large rocks and coarse gravel. The water pipe was severely corroded and had three large holes on top of the pipe facing the oil pipeline*.[17]

Although Enbridge reported that eight in-line inspections from 2000 to 2008 did not identify problems with the pipe in the area of the damage, "an August 2008 inspection using a magnetic flux leakage (MFL) tool identified a metal object near the area of the damaged pipeline. Records indicated no history of excavation to repair or work on the pipeline at the location of the leak."[17] The NTSB investigation determined the probable cause of the pipeline leak to be "erosion caused by water jet impingement from a leaking 6-inch diameter water pipe 5 inches below the oil pipeline" but did not determine the cause of the erosion of the waterline.[17] **Enbridge filed suit against the Village of Romeoville** alleging that the Village "negligently failed to prevent the leak of a lateral water service Line".[18] The Village argued, inter alia, that "according to Enbridge's experts, the cause of the water leak was stray current corrosion which led to the Water Jet Slurry which led to the impingement or erosion of a hole in the Oil Pipeline", with the stray current emanating from a corrosion protection system on the Enbridge pipe.[18] **The village filed a motion for summary judgment, and on August 10, 2016 the Court granted the motion.**[19]

October 15, 2010: A release of crude oil occurred at a sample port in a meter bank at Enbridge's Nanticoke, Ontario, terminal. Approximately 124 barrels was released onto industrial property in the area.[8]

May 9, 2011: A leak was discovered on Enbridge's Norman Wells Pipeline approximately 50 meters south of Wrigley and 150 meters south of Willowlake River in the Northwest Territories. Enbridge estimated the leak volume to be about four barrels. After implementing a full-scale environmental site assessment (ESA) program, which included subsurface analysis and investigation, Enbridge discovered the leak volume and subsurface contamination was greater than originally estimated. The ESA indicated that a large quantity of oil was held below the surface by permafrost, which served as a cap preventing the upward movement of the oil and an initial visual determination of the full extent of the leak volumes. Based on estimates provided by third-party experts on site, Enbridge later reported that it anticipated the leak volume to range from 700 to 1,500 barrels. The subsurface that was affected is about one acre.[8]

December 2011: a Canadian judge fined Enbridge $875,000 for safety violations linked to a 2003 natural gas pipeline explosion in Toronto that killed seven people.[20]

March 3, 2012: Two third-party vehicles left the end of a public road (T-intersection) within an industrial area and struck an above ground pig sending trap within an Enbridge fenced facility on Line14/64 near

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[18] See Exhibit #4
[19] See Exhibit #5
[20] Enbridge Gas fined in deadly Etobicoke explosion, National Post ,http://news.nationalpost.com/posted-toronto/enbridge-gas-fined-in-deadly-etobicoke-explosion

New Lenox, Illinois. A drain line on the bottom of the pig sending trap severed, and a release of crude oil and fire occurred. The collision resulted in two fatalities at the scene; both were occupants of the third-party vehicles. An estimated 1,500 barrels of crude oil were released from the pig sending trap; of that amount, more than 1,200 barrels were estimated to have been consumed during the fire.[8]

June 18, 2012: Approximately 1,446 barrels of crude oil leaked at Enbridge's Elk Point Pump Station on Line 19 (Athabasca Pipeline) near the town of Elk Point, Alberta. Approximately 188 barrels was released on an adjacent landowner's field.[8]

July 27, 2012: EEP reported a release of crude oil from Line 14 on its Lakehead System near Grand Marsh, Wisconsin. The oil was contained in a field. The initial estimate of the volume released was approximately 1,200 barrels On July 30, 2012, the Pipelines and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order with conditions to return Line 14 to service, and on August 1, 2012, PHMSA issued an amendment to the Corrective Action Order with additional restart conditions. Enbridge submitted the Restart Plan to PHMSA on August 1 and the Lakehead Plan to PHMSA on August 2. The Lakehead Plan describes improvements that to be made in operational areas on the Lakehead System.[8]

Jul 29, 2012: The Grand Marsh spill occurred shortly after the publication of the damning National Transportation Safety Board report blasting Enbridge's handling of the July 2010 Kalamazoo disaster. U.S. Representative Ed Markey responded by saying: "Enbridge is fast becoming to the Midwest what BP was to the Gulf of Mexico." PHMSA told the company not to reopen the pipeline until the agency had approved a plan for corrective action.[21]

February 2, 2013: Approximately 220 barrels of crude oil leaked from an Enbridge gathering line near Storthoaks, Saskatchewan. The surface area of the leak was approximately 335 square yards and the subsurface contamination reached approximately 3,348 square yards. The leak was caused by corrosion damage caused by the failure of the external coating of the pipe's surface.[8]

May 13, 2013: Approximately 2,200 barrels of crude oil spilled from an Enbridge trunk line at the South Terminal in Cushing, Oklahoma. The oil traveled in a ditch to a small containment pond near an Enbridge tank. The oil flowed from the small containment pond into an adjacent creek and then into a large containment pond. This incident involved several animal fatalities and rehabilitations.[8]

June 22, 2013: Ground movement caused a spill on Enbridge Line 37 of approximately 1,300 barrels of oil near Cheecham, Alberta. The spill traveled above ground and into a nearby lake.[8]

August 3, 2013: Approximately 140 barrels of crude oil spilled from the Enbridge Griffith Terminal. The spill impacted approximately 7.33 acres of land.[8]

November 21, 2013: Approximately 101 barrels of crude oil spilled from Enbridge Line NB-07 near Stoughton, Saskatchewan.[8]

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[21] Enbridge t o replace leaky Wisconsin oil pipeline Monday, Reuters ,http://www.reuters.com/article/us-enbridge-pipeline-idUSBRE86S0KE20120729

March 14, 2013: The U.S. Environmental Protection Agency today ordered Enbridge to do additional dredging to clean up oil from the company's July 2010 pipeline spill in Kalamazoo River "above Ceresco Dam, upstream of Battle Creek, and in the Morrow Lake Delta."[22]

January 18, 2014: Approximately 113 barrels of crude oil spilled from the Rowatt pump station, south of Regina, Saskatchewan, on Line 67 after a pressure transmitter steel flex hose failed in the station piping. The oil spilled onto the grounds of the pump station and onto nearby farmland. An incident investigation concluded that the support of the pressure transmitter assembly did not sufficiently protect the steel braided hose from excessive stress associated with the high winds in the area.[8]

February 22, 2014: Enbridge Line 9 through Ontario, Canada, has had at least 35 spills but Canada's National Energy Board (NEB), "which regulates pipelines in Canada, has records of seven spills". CTV W5 investigations revealed the false reporting, raising questions about other spill numbers in NEB records.[23]

February 25, 2014: Approximately 975 barrels of crude oil spilled from station piping within a manifold inside the Griffith, Indiana Terminal caused by a failed piping connection.[8]

March 21, 2014: Enbridge recovered approximately 200 barrels of oil from a spill at the Maxbass station in Maxbass, North Dakota, caused by a leak in an underground tank line that had been connected to previously removed tank.[8]

April 18, 2014: Approximately 113 barrels of crude oil leaked from a tank mixer at the Enbridge Edmonton Terminal after a seal failed.[8]

December 16, 2014: Enbridge reported a flange or valve failure caused spill of approximately 1,346 barrel oil spill from its Line 4 pipeline at the Regina Terminal in Saskatchewan, Canada.[24] [8]

July 2015: Canada's National Energy Board (NEB), released an audit report that concluding that "the Calgary-based energy giant wasn't addressing threats to public safety from its pipelines and [was] failing to adequately protect whistleblowers."[25] **Error! Bookmark not defined.** But the final report deleted parts the draft version that was privately shared with Enbridge in February 2015 regarding the ability of the company to monitor and repair pipeline cracks caused by corrosion.[25] Don Deaver, a pipeline and oil and gas industry expert said after reviewing documents provided by whistleblowers, "They don't even understand their limitations and the NEB has no idea what the issues are."[25] Deaver continued **"Whenever there's a lawsuit on a spill or something like that, the agencies allow the companies to hold back the reports until there's a settlement. It could be embarrassing to the regulatory people (to reveal what's in these company reports) because it could show that they (regulators) failed to take action**."[25]

[22] News Releases - Emergency Response, U.S. Environmental Protection Agency, https://yosemite.epa.gov/opa/admpress.nsf/324e040292e1e51f85257359003f533a/19cdd21822f762cd85257b2e006ecbb9%21opendocument

[23] Enbridge Line 9: W5 uncovers unreported spills, alarming communities along 830-km pipe. Toronto Star. https://www.thestar.com/news/gta/torontopipeline/2014/02/22/enbridge_line_9_w5_uncovers_unreported_spills_alarming_communities_along_830km_pipe.html

[24] Enbridge says no restart time yet for biggest oil export pipeline , Reuters, http://www.reuters.com/article/enbridge-line4-leak-idUSL1N0U218R20141218

[25] Pipeline watchdog hid evidence of secret Enbridge reports. National Observer, http://www.nationalobserver.com/2016/05/02/news/heres-how-enbridge-edited-federal-pipeline-audit

II. REQUEST FOR MAXIMUM FINES

A. Legal Framework

In Complaint, United States of America (Plaintiff), in paragraph B of REQUEST FOR RELIEF, requests the Court in part to "Issue an order pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b), requiring Defendants to take all appropriate actions to prevent future discharges of oil to waters of the United States from facilities owned or operated by Defendants within the United States". This request is consistent with the opinion of The United States District Court for the Eastern District of Louisiana. See In re Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico, on Apr. 20, 2010, 841 F. Supp. 2d 988, 1004–05 (E.D. La. 2012) which states that the purpose of the CWA is not just remedial, but also punitive/deterrent:

> Legislative history and case law reveal that a Section 311(b)(7) civil penalty has multiple goals, including restitution, but the primary objectives are to punish and deter future pollution. For example, the House Conference Report on OPA (which also amended the CWA) stated, "Civil penalties [under the CWA] should serve primarily as an additional incentive to minimize and eliminate human error and thereby reduce the number and seriousness of oil spills." H.R.Rep. No. 101–653, Sec. 4301, at 52 (1990) (Conf. Rep.), *reprinted in* 1990 U.S.C.C.A.N. 779, 833. In *Tull v. United States,* the Supreme Court analogized a civil penalty under Section 309(d) of the CWA, 33 U.S.C. § 1319(d)—which is similar in relevant aspects to Section 311(b)(7)—to punitive damages; i.e., those "remedies intended to punish culpable individuals, as opposed to those intended simply to extract compensation or restore the status quo." 481 U.S. 412, 422 & n. 7, 107 S.Ct. 1831, 95 L.Ed.2d 365 (1987) (analyzing whether a claim for CWA penalties implicated the Seventh Amendment). The Court added, "The legislative history of the [CWA] reveals that Congress wanted the district court to consider the need for retribution and deterrence, in addition to restitution, when it imposed civil penalties." *Id.* at 422, 107 S.Ct. 1831; *see also Kelly v. EPA,* 203 F.3d 519, 523 (7th Cir.2000) (citing *Tull,* 481 U.S. at 422–23, 107 S.Ct. 1831) ("Civil penalties under the [CWA] are intended to punish culpable individuals and deter future violations, not just to extract compensation or restore the status quo."); *Montauk Oil Transp. Corp. v. Tug El Zorro Grande,* 54 F.3d 111, 114 (2d Cir.1995) (stating that a penalty under CWA Section 311(b)(6), which is similar in many respects to Section 311(b)(7), "is not predicated upon the cost of removal, but upon the happening of the discharge. The determinative factor ... is the discharge of oil, not its cleanup," indicating that the primary purpose is deterrence); *United States v. Atlantic Richfield Co.,* 429 F.Supp. 830, 837 (E.D.Pa.1977) ("[T]he principal goal of [Section 311](b)(6) is to deter spills.... [T]he Congressional purpose here was to impose a standard of conduct higher than that related just to economic efficiency.... [E]ven where defendants are not at fault, the penalty does not act only as punishment but serves the ends of civil regulation."); *cf. United States v. Coastal States Crude Gathering Co.,* 643 F.2d 1125, 1128 (5th Cir.1981) ("The purpose of [CWA Section 311] is to achieve the result of clean water as well as deter conduct causing spills." (citation and quotations omitted)); *United States v. Tex–Tow, Inc.,* 589 F.2d 1310, 1315 (7th Cir.1978) ("Tex–Tow's claim of irrationality is grounded in the assumption that the purpose of the civil penalty [in Section 311(b)(6)] is to Deter spills.... [However,] the civil penalty ***also*** has certain non-deterrent, economic purposes ...." (Emphasis added)).

Complaint lists nine companies (Defendants), all "persons", who "at all times relevant to this action … owned and/or operated Line 6A and Line 6B" ("EESCI succeeded to certain liabilities of EPI, including liabilities arising from the 2010 oil discharges from Line 6A and Line 6B"), and are "responsible parties" and ""subject to a civil penalty for the violations in this case." See Complaint paragraphs 6 – 15, 44, and 59.

In cases of multiple permit violations, each violation is to be treated as a "separate and distinct infraction for purposes of penalty calculation." See United States v. Smithfield Foods, Inc., 191 F.3d 516, 528 (4th Cir. 1999) citing:

> *Public Interest Research Group of New Jersey, Inc. v. Powell Duffryn Terminals, Inc.*, 913 F.2d 64, 78 & n. 28 (3d Cir.1990) (holding that violation calculations should be analyzed "on a parameter by parameter basis" and that each type of effluent limit is "clearly separate" and there is "no reason why [a defendant] should not be penalized separately for violating each limitation"); *Natural Resources Defense Council, Inc. v. Texaco Ref. & Mktg., Inc.,* 800 F.Supp. 1, 21 (D.Del.1992) (finding that "separate exceedances of weight and concentration limits can constitute separate violations"); *Student Pub. Interest Research Group of New Jersey, Inc. v. Monsanto Co.,* No. CIV.A.83–2040, 1988 WL 156691, at *11 (D.N.J. Mar.24, 1988) (concluding that "[e]ach violation of any express limitation in the permit may, of course, be treated as a separate violation for the purposes of assessing a penalty"); *United States v. Amoco Oil Co.,* 580 F.Supp. 1042, 1046 n. 1 (W.D.Mo.1984) (suggesting that the CWA allows for separate penalties for violations of the daily limit of different pollutants).
>
> See also United States v. Smithfield Foods, Inc., 972 F. Supp. 338, 340–41 (E.D. Va. 1997):
>
> In accordance with the clear holding of the Fourth Circuit Court of Appeals in *Chesapeake Bay Foundation. Inc. v. Gwaltney of Smithfield, Ltd.,* 791 F.2d 304, 314–15 (4th Cir.1986) (each violation of a monthly average limit shall be treated as a violation for every day in the month in which the violation occurred, rather than as a single violation for that month), *rev'd on other grounds,* 484 U.S. 49, 108 S.Ct. 376, 98 L.Ed.2d 306 (1987), *remanded,* 844 F.2d 170 (4th Cir.), *judgment reinstated,* 688 F.Supp. 1078 (E.D.Va.1988), *aff'd in part. rev'd in part on other grounds, and remanded,* 890 F.2d 690 (4th Cir.1989), this court will count each violation of a monthly average concentration or loading limit as a violation for every day of the month in which the violation occurred.[2] Furthermore, if multiple violations of the Permit occur on the same day, defendants are liable for a separate day for each violation of the Permit, including the daily maximum, monthly average concentration, and monthly average loading limits for each pollutant. This determination is consistent *341 with Section 309(d) of the Act, which specifically provides for a "civil penalty not to exceed $25,000 *per day for each violation*" (emphasis added), rather than a statutory maximum of $25,000 *per day.* The different pollutants, and their daily maximum, monthly average concentration, and monthly average loading limits, are included in the Permit for different reasons. Each limit is a separate, distinct requirement in the Permit which can be violated. Accordingly, where multiple violations of defendants' Permit occur on one day, the maximum penalty on that day may exceed $25,000

B. Analysis

In the instant case, Plaintiff's stated goal is to "take all appropriate actions to prevent future discharges of oil to waters of the United States from facilities owned or operated by Defendants within the United States" (See Complaint, paragraph B of REQUEST FOR RELIEF). Rather than following legislative and case law calling for punitive/deterrent actions outlined above, Plaintiff includes a bizarre plan in the Consent Decree demanding the construction of new crude oil pipelines ((Consent VII-B), a plan already publically advertised by Defendants[26]. Such a plan is antithetical to Plaintiff's own stated goals as set forth by its Environmental Protection Agency in multiple actions, widely available public proclamations, and regulations. (For example, see The Clean Power Plan[27]). A demand that Defendants construct a new larger pipeline, a plan already in process, is not an "appropriate action" considering Defendants accident history (See Table 1). Plaintiff fails to abide by its own legislative history and case law outlined above calling for punitive/deterrent action. Plaintiff also fails to abide by its own legislative history by calling for civil penalties less than maximum (See subsection C below), and assessing those penalties to Defendants as a group rather than individually. **The authors and signatories to this response believe Plaintiff has the legal right and responsibility to assess the full maximum amount for civil penalties in the instant case to each of the nine companies listed as Defendants**.

C. Justification & Request: Maximum fines

The proposed civil penalty assessed in this Consent Decree is $1 million for the Romeoville spill and $61 million for the Marshall, Michigan spill. The full penalty, if assessed, would be more than $840 million or close to $1 billion. We will present argument that this penalty is necessary and will fulfill a need for citizen involvement.

The civil penalty as proposed is based on violations of the Clean Water Act but the maximum penalties are not asked for by the Department of Justice and the EPA. Is this due to Enbridge's payment for damages to date to both the State of Michigan and to the reimbursement of removal costs to the Oil Spill Liability Trust Fund and their commitment to pay for future damages as required? And it appears, in response to this spill, Enbridge and the EPA have outlined a new program to follow to prevent future incidents with these specific lines.

In its SEC filing for June 30, 2014 Enbridge Energy Partners, L.P. (one of Defendants) discusses the many lawsuits it was fighting to avoid the cost of spill damages.[28] A case in point is the lawsuit naming the Village of Romeoville discussed in the September 9, 2010 incident report in I.C (Spill Data) above and granting of Summary Judgment in favor of the Village. Thus, we ask that the Department of Justice and EPA reconsider their leniency in not charging the maximum fines given the following:

1. Enbridge controls **4,608** (*not 3,000 as noted in the Complaint*) miles of pipeline in the United States alone with the majority of the pipelines in the upper Midwest.[29] The corrections cited in Consent Decree that Enbridge proposes to make to their protocols and way of doing business now mostly involves the Lakehead Pipeline System only. And these proposed corrections to how they do business in the Lakehead Pipeline System only came at the expense of an irreparable oil spill.
2. Enbridge also has a history of relying on the observation of non-employees - not their touted monitoring systems - to discover spills and leaks such as the gas company employee and a random 'passerby' who discovered and reported the leaks in the

[26] See Exhibit #6

[27] The Clean Power Plan, U.S. EPA, https://www.epa.gov/cleanpowerplan

[28] See pages 21, 22, 73 on Exhibit #7

[29] Enbridge Energy, Limited Partnership / Operator Information. Pipeline Safety Stakeholder Communications https://primis.phmsa.dot.gov/comm/reports/operator/OperatorIM_opid_11169.html?nocache=3684#_OuterPanel_tab_3

Kalamazoo[30] and Romeoville[31] disasters. In addition, a news agency in Ontario uncovered ***more leaks than reported*** in 2014 for Enbridge Line 9, raising the question of whether or not leaks are not reported unless discovered by outside agencies or public observers.[32] And in at least one instance, a Canadian government agency worked to reduce public observation of their pipeline.[33]

3. Paying maximum fines, in line with United States law calling for punitive/deterrent actions (See II.B above), is now mandatory to encourage Enbridge to reconsider the risks it takes with our Commons - specifically the water supply of over 30 million people. An example of Enbridge's lack of proper concern and sense of responsibility is well illustrated by the fact that Line 5 is still in operation. The Lakehead Pipeline System includes 62-year-old Line 5 that travels thru the Straits of Mackinac between Lake Michigan and Lake Huron. It is now known that portions of Line 5 are corroded.[34] Do we wait then for a $1 billion[35] spill to occur before the Department of Justice and the EPA realize that these fines assessed to date mean very little to this energy giant? Enbridge has already downplayed the danger posed by keeping this ancient relic in operation as detailed in research gathered by FLOW.[36] Waiting for a technology to be developed at some unknown date in the future as suggested on Page 12 of the Consent Decree is not an acceptable response either given what the loss and damage a spill would do to millions who depend on Lake Michigan for their water supply.

The authors and signatories to this response request maximum penalties be assessed as per Section 311 of the CWA, 33 U.S.C. § 1321 for the Line 6A spill at $4,300 per barrel and for Line 6B spill at $1,100 ***per each of the nine defendants*** as stated on Page 17 in the Complaint:

"…each Defendant is liable for a civil penalty of up to $4,300 per barrel discharged from Line 6B and a civil penalty of up to $1,100 per barrel discharged from Line 6A."

Enbridge, has time and time again allowed inadequate maintenance and prevention standards that allow oil leaks and spills into the Midwest region's water and land. Assessing the maximum fine sends a message that has not been sent prior to this occasion (see Table 1) that it is expected by this and/or any oil company that maintenance and prevention of spills and leaks protocols need to be

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[30] PHMSA Announces Enforcement Action Against Enbridge for 2010 Michigan Oil Spill http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=0faf7fe7f1a38310VgnVCM1000001ecb7898RCRD&vgnextchannel=71edbcb4377e7310VgnVCM1000001ecb7898RCRD&vgnextfmt=print

[31] NTSB Pipeline Accident Brief http://www.ntsb.gov/investigations/AccidentReports/Reports/PAB1303.pdf

[32] 3.3 Unreported And Inadequate Spills Response, by Louisette Lanteigne https://piperisks.wordpress.com/2015/07/10/1/

[33] Waterloo Woman Finds NEB E-Mail Lauding Public's Inability To Question Pipelines*, by Mychaylo Prystupa* http://www.vancouverobserver.com/news/waterloo-woman-finds-neb-e-mail-lauding-public-s-inability-question-pipelines

[34] Recently released Enbridge report shows areas of corrosion along Line 5, by Mark Brush Michigan Public Radio. http://michiganradio.org/post/recently-released-enbridge-report-shows-areas-corrosion-along-line-5#stream/0

[35] $1 billion cleanup cost estimated for a winter Mackinac straits oil spill, by Garret Ellison http://www.mlive.com/news/index.ssf/2016/05/mackinac_straits_spill_cost.html

[36] Enbridge Downplaying the Potential Size of Catastrophic "Line 5" Straits Oil Spill http://flowforwater.org/wp-content/uploads/2016/05/FINAL-Line-5-Spill-Scenarios-05-02-16.pdf

followed to the letter - that failure to proceed with caution and concern for our water and land will be met with maximum monetary fines which may prove to be hazardous to their business' future.

We would like to bring to your attention the National Academy of Science's 2016 study[37] that indicates that tar sands-based oil, with its toxic chemical mix, is significantly more difficult to clean up if a spill occurs than a crude oil spill. The time window for addressing such a spill is short -- so when it's not discovered right away, which is typical and almost guaranteed for buried pipelines, which affects the cleanup. In fact, the findings are that unless the tar sands oil is immediately cleaned up, the chances of 100% cleanup are lost.

Requiring Enbridge's to pay for cleanup and to institute more stringent procedures would have been commendable if the price paid by this region for these concessions didn't involve the current and future health of the humans, as well as the flora, fauna in both regions. Oil spilled is not a simple matter of saying 'sorry' and moving on with a better attitude and plan. It is not something the people of these regions will 'just' get over. This spill is not only affecting this generation but will affect generations to come. The penalty should reflect this multi-generational loss.

Enbridge's lack of knowledge or concern is illustrated by their lack of interest, or 'follow-thru' or at least curiosity in determining what other pipelines were in place near theirs preceding the Romeoville spill given the number of JULIE requests received prior to the spill. What does this indicate for the spider web of pipelines throughout this region that crisscross other pipelines in our cities and towns - not to mention our water supplies? This lack of interest, concern indicates a company-wide, endemic attitude that scorns details and the public safety. All the more reason for additional citizen oversight for this infrastructure.

Questions for Plaintiff (United States of America):

1. In negotiating the less than maximum penalty in this Consent Decree, did Plaintiff consult with the Village of Romeoville? If the answer is no, it seems that to fully investigate the question of maximum penalties and to deter future irresponsible action on the part of Defendants, as in the Kalamazoo spill, the Consent Decree must be renegotiated with a full investigation and will all injured parties participating.
2. In negotiating penalty amounts, did Plaintiff consider the history of Enbridge Line 14 spills in Wisconsin and that "following the January 1, 2007 failure, [Enbridge] utilized ultrasonic crack detection technology to assess the Affected Pipeline. Multiple crack anomalies associated with the ER W seam were reported by the inline inspection (ILI) vendor. Based on the ILI results, Respondent made repairs to the Affected Pipeline for a 1.25 x MOP factor of safety. Calculations performed by Respondent in 2008 predicted that Line 14 would not fail for a minimum of 10 years" and that the same Line 14 ***failed again five years later for the same reason***.[38]
3. Did Plaintiff ask why a major spill into the streets of Romeoville was undetected by Enbridge, and discovered by local citizens?
4. Did Plaintiff ask why it took 35 to 40 minutes from the time the Romeoville assistant fire chief notified Enbridge of a major spill to the time firefighters could see the flow noticeably diminish?

[37] Committee on the Effects of Diluted Bitumen on the Environment, Spills of Diluted Bitumen from Pipelines: A Comparative Study of Environmental Fate, Effects, and Response, The National Academies Press 2016 http://www.nap.edu/read/21834/chapter/2#3

[38] See Exhibit #8

Section 309(g)(2)(B) of the CWA does not set forth a minimum penalty and given the hardship to be endured generationally, *only a maximum, a "top down" approach should be applied to determining the amount of the penalty*. In other words, the Administrator should begin with regulatory maximum and adjust downward, only if justified, based on the statutory factors indicated in Section 309(g)(3) of CWA, rather than starting at $0 or some other arbitrary baseline and working up from there. As was explained in *Atlantic States Legal Found., Inc. v. Tyson Foods, Inc.*, 897 F.2d 1128 (11th Cir. 1990), "the district court should first determine the maximum fine ... [I]f it chooses not to impose the maximum, it must reduce the fine in accordance with the factors [i.e., those described in Section 309(g)(3) of CWA]". See also *United States v. Marine Shale Processors*, 81 F.3d 1329, 1327 (5th Cir. 1996), "courts often begin by calculating the maximum possible penalty, then reducing that penalty only if mitigating circumstances are found to exist". *Public policy dictates that Respondent should bear the burden of justifying any reduction from the maximum, rather than the public justifying an increase from $0.*

As part of this settlement agreement, Enbridge has agreed to install new monitoring equipment, implement an inspection and cleaning schedule for its pipeline infrastructure and inspections to prevent unauthorized discharges. We find this extremely disingenuous of Enbridge, the DOJ and the EPA. All of these things—the "new" monitoring equipment, inspection and cleaning schedules—should have been in place as a condition of operating in the first place or a part of standard operations of a multi-billion dollar international corporation. In fact, we find anything less than this standard a violation of operating procedures and permits. These token offerings are just that, as well as a ploy to seek smaller penalties.

Questions for Plaintiff (United States of America) cont.:

5. In negotiating the less than maximum penalty in this Consent Decree, did Plaintiff know that "Enbridge and TransCanada have each committed $1.6-million to the ELDER [external detection] project, while Kinder Morgan has committed $1-million."?[39]
6. Before penalizing Enbridge by demanding external leak detection research, did Plaintiff know Enbridge publically posted: "Specifically, central Missouri, where we've buried fiber optic cable alongside a 20-mile (32-kilometer) stretch of our newly built Flanagan South pipeline. 'Essentially, our testing of external leak detection systems is increasing to an even larger scale with this fiber optic pilot project in Missouri', says Cam Meyn, a supervisor of testing and research in Enbridge's Leak Detection department."?[40]
7. Does plaintiff know that true external leak detection technologies (gas/tracer sensing technologies) have existed for years but companies designated as "public utilities" such as Enbridge consider them too expensive?[41] If so, what price does Plaintiff consider too high to assess a foreign company for protecting our irreplaceable Commons?

Plaintiff has a responsibility to protect the Commons for the citizens and residents of the United States. As owners of the Commons, how are we to believe that Enbridge, a private company with understandable self-interest, will act differently as a result of the Consent Decree without a full investigation, with less than maximum penalties, and with gifts of the new construction of replacement Line 3 fast-tracking and calls for external leak detection research -- research that already exists?

[39] See Exhibit #9
[40] See Exhibit #10
[41] See page 4.5 in Exhibit #11

Questions for Plaintiff (United States of America) cont.:

8. In negotiating the less than maximum penalty in this Consent Decree, did Plaintiff know that Enbridge has launched a public relation image campaign to counter its image after the Kalamazoo and Romeoville spills.[42]
9. Is Plaintiff aware of Enbridge's rebranding ad campaign?[43]
10. Does Plaintiff consider investing in a public relations blitz an appropriate action for the company Plaintiff has chosen to assess less than maximum penalties?

Given the history of repeated and various violations, outlined in detail in Section I, we request that the maximum penalty of $86,352,600 be assessed in this case for each defendant in the Line 6B spill , and for a maximum penalty of $7,069,700 for each defendant in the Line 6A spill. In line with United States law calling for punitive/deterrent actions (See II.B above), we ask that each of the nine defendants listed in the complaint be fined and that this combined amount totaling close to $840 million be the amount used to create the Regional Citizens' Advisory Councils and Area Committees as outlined in Section III**.**

III. ADDITIONAL CONDITIONS UNDER THIS SETTLEMENT AGREEMENT

This proposed Consent Decree follows the same pattern as previous settlements by requiring more technology and more internal company monitoring and inspections. This is just more of the same fox guarding the same henhouse, and it will produce the same results – more self-reported or unreported pollution discharges into our water supplies, our farms, our cities and towns from daily operations, more oil and chemical spills into the same, further weakening of industry-government vigilance, and declining environmental and social standards. **The Independent Third Party - to be named by Enbridge - *is not acceptable***. This Consent Decree and its token agreements provide us with no sense of relief or confidence that Enbridge's aging and ever-expanding pipeline infrastructure will be any safer. We want and deserve more.

A. Justification for commenters' requests

Previous events set precedent for our following request for four additional conditions under this settlement agreement. The abbreviated track record for Enbridge operations in North America in Table 1 shows a history of systemic problems resulting in large penalties and systemic solutions as part of settlement conditions. Given this abbreviated history of spills and leaks, why should we, the people of the Midwest, consider that these systemic problems will change with this single document?

In light of this and all concerns outlined in Section II, we request three additional conditions under this Consent Decree. Each features independent programs to involve area residents in review and oversight of the Enbridge pipeline infrastructure that potentially affects their lives, health, and wellbeing.

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[42] See new Enbridge website here http://www.enbridge.com/. Archived, pre-Kalamazoo websites available on request.

[43] New Enbridge ad campaign shows everything but pipelines, News 1130, http://www.news1130.com/2014/09/23/new-enbridge-ad-campaign-shows-everything-but-pipelines/

B. A Lake Michigan Regional Citizens' Advisory Council (RCAC) and Upper Mississippi Regional Citizens' Advisory Council (RCAC)

There are only two places on the planet where oil operations were actually made significantly safer, in terms of prevention and response, and both occurred after an oil spill "accident" – or rather, after a ***predictable consequence*** of an oil company's cost-cutting and negligent behavior. These places are in Scotland and Alaska, at the two majority BP-owned tanker terminals in Sullom Voe and Prince William Sound, respectively. The successful solution was the same in both cases: independent, funded regional citizen advisory councils to involve local people in the process of safeguarding oil activities in their backyard.

The Oil Pollution Act of 1990 (OPA 90) specifically calls out the importance of citizen and community engagement when it comes to oversight and monitoring of petroleum facilities. Excerpting from 33 U.S.C. 2732,

(2) **Findings** The Congress finds that—

(A) **...**

(B) many people believe that complacency on the part of the industry and government personnel responsible for monitoring the operation of the Valdez terminal and vessel traffic in Prince William Sound was one of the contributing factors to the EXXON VALDEZ oil spill;

(C) one way to combat this complacency is to involve local citizens in the process of preparing, adopting, and revising oil spill contingency plans;

(D) a mechanism should be established which fosters the long-term partnership of industry, government, and local communities in overseeing compliance with environmental concerns in the operation of crude oil terminals;

(E) ...

(F) **...**

(G) the present system of regulation and oversight of crude oil terminals in the United States has degenerated into a process of continual mistrust and confrontation;

(H) only when local citizens are involved in the process will the trust develop that is necessary to change the present system from confrontation to consensus;

(I) **...** and

(J) similar programs should eventually be established in other major crude oil terminals in the United States because the recent oil spills in Texas, Delaware, and Rhode Island indicate that the safe transportation of crude oil is a national problem.

OPA 90 created two pilot programs in Alaska by empowering "two already existing citizens' councils to help combat the complacency seen as responsible for the 1989 spill and to provide a needed layer of scrutiny to increase public confidence in the safety of Alaska's oil transportation system. The council role, defined by OPA 90 as purely advisory, was to help correct the problems leading to the oil spill by fostering partnership among the oil industry, government, and local communities in addressing environmental concerns."[44]

When set up correctly, citizens' advisory councils work. We incorporate into our comments by reference, Prince William Sound RCAC's 2012 white paper, "The role of citizen oversight in the safe

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[44] PWSRCAC, 2012, Role of Citizen Oversight. http://www.pwsrcac.org/wp-content/uploads/filebase/resources/citizen_oversight_and_history_of_the_council/Role%20Of%20Citizen%20Oversight%20In%20The%20Safe%20Management%20Of%20Oil%20Transportation%20Operations%20And%20Facilities%20In%20Prince%20William%20Sound%20-%20February%202012.pdf

management of oil transportation operations and facilities in Prince William Sound." Of special note are the three structural attributes necessary for effective and constructive citizen oversight, including: independence, assured funding, and access.[45]

We also incorporate into our comments by reference, a white paper by professor Rick Steiner, "Citizens' advisory councils to enhance civil society oversight of resource industries," published in the United Nations Environment Program's journal *Perspectives* in June 2013, issue 10.[46] Net benefits of independent, funded, and informed citizens' advisory councils include a marked improvement in spill prevention, risk reduction, and environmental and social standards. Steiner writes:

> *" ...local civil society stakeholders need to be directly involved in the review and oversight of resource industry operations that potentially affect their lives, including extractive industries such as oil, gas and mining; and renewable industries such as agriculture, forestry, and fisheries. Local citizens have much at stake, and much to offer, in the safe and responsible conduct of resource development in their region. To be effectively engaged, citizen stakeholders need their own organization with sufficient funding, staff, authority, broad representation, and independence. …"*

Under OPA 90, the oil industry was not allowed to have a voting seat on the council. Local governments were, but this proved too unwieldy to be functional in densely populated regions; i.e., basically anywhere else in the nation, except Alaska, that safe transportation of crude oil is a national problem. Further, the voting seats for local government may no longer be necessary or desirable, given that OPA 90 also required a third tier of government in the national organizational and planning structure for oil spill response; specifically, Area Committees, discussed in the next subsection.

Given the marked success of the Prince William Sound RCAC and Congress' intent of establishing similar programs in areas where the handling and transporting of oil is a national concern, we request, as a condition of this settlement, establishment of a Lake Michigan Regional Citizens' Advisory Council (RCAC) AND an Upper Mississippi Regional Citizens' Advisory Council (RCAC) with key stakeholder groups, modeled after the Prince William Sound RCAC established under the OPA 90.

C. A Lake Michigan Area Committee and Upper Mississippi Area Committee

Under the Oil Pollution Act of 1990, Congress established Area Committees comprised of local agencies to address community needs and practical response to man-made disasters, similar to the roles and responsibilities of local governments to natural disasters under SARA (Superfund Amendments and Reauthorization Act) Title III.

Instead of establishing Area Committees throughout the country for technological disasters as per the Congressional mandate through OPA 90—similar to what occurred after passage of SARA Title III with establishment of Local Emergency Planning Committees for natural disasters, EPA left the structure of oil spill response planning essentially unchanged as the responsibility of state and federal agencies—that basically defer to industry for site-specific response plans; i.e., Spill Prevention, Control, and Containment (SPCC) Plans.

[45] PWSRCAC, 2012, Role of Citizen Oversight.

[46] Steiner, Rick, 2013, Citizens' Advisory Councils. http://www.unep.org/civil-society/Portals/24105/documents/perspectives/ENVIRONMENT_PAPERS_DISCUSSION_10.pdf

We find this unacceptable for two primary reasons. First, as recognized by Congress, local governments are in the best possible position to plan for and protect communities and the environment in the event of fires, explosions, spills, chronic pollution, and related incidents that result from infrastructure responsible for moving oil, hazardous and noxious substances through our region. The risks from incidents such as spills and leaks among other things, have the potential to cause significant impacts to health and safety of citizens, first responders and the environment. The risks require the involvement of local governments to minimize the consequences to their communities. However, local governments have not been adequately integrated into this process of risk assessment and response planning for man-made disasters, including all impacts and consequences on local communities and governments, as they have for natural disasters.

Second, local government has a duty to protect public health, safety and wellbeing; industry has a duty to maximize profits for its shareholders. These duties inherently conflict as industry profits often come at the expense of human safety and health and the environment – as shown in Table 1. Therefore, it is critical that local governments are involved in risk assessment and response planning carried out by industry and other tiers of government environment. To do this, local governments need sufficient funding, staff, authority, and independence – essentially the same structural attributes necessary for effective and constructive citizen oversight, as mentioned above.

Given Congress' intent of establishing a third tier in the national oil and chemical disaster response structure specifically to address practical concerns and local knowledge and the EPA's failure to follow the law, we request, as a condition of this settlement, establishment of a Lake Michigan Area Committee and an Upper Mississippi Area Committee comprised of local, state, and federal agencies, as mandated under the Oil Pollution Act of 1990.

D. An independent environmental monitoring program

In lieu of the proposed Independent Third Party as outlined in paragraphs 125 forward in the Consent Decree, we request that each of the proposed Citizen Review Councils vet and hire this entity to act in their jurisdiction, thereby assuring the Department of Justice and the EPA that there are 'eyes on the ground' to ensure that this entity achieve the outcomes proposed in the Consent Decree.

Therefore, we request, as a condition of this settlement, establishment of an independent environmental monitoring program for the Enbridge pipeline infrastructure modeled after the environmental monitoring program conducted by the Prince William Sound RCAC for the Alyeska tanker terminal.

E. An independent environmental review of Line 3 and Line 10

We, the authors and signatories to this response agree to the request for the decommissioning of Original US Line 3 as outlined in section B, page 156 of the Consent Decree. We, the authors and signatories to this response ***do not agree*** to a New Line 3 and are curious as to why this is included as part of the penalty decree? We request that prior to any approval, construction, or breaking of ground be made on a New Line 3, the newly established Upper Mississippi Regional Citizens Review Board be allowed to review and assess the need for a New Line 3.

And as with Line 3, we also request review and assessment be made by the newly established Lake Michigan Regional Citizens' Review Board for any approval, new construction, or breaking of ground to be made regarding Line 10.

F. Funding for additional conditions

As conditions of this settlement, we request $20 million ***annually*** for a Lake Michigan Area Committee and an Upper Mississippi Area Committee and $20 million ***annually*** for a Lake Michigan RCAC and an Upper Mississippi RCAC. An estimate of annual operating expenses were calculated based on a conversation [Riki Ott had] with the Prince William Sound Regional Citizens' Advisory Committee, with allowances for increased program complexity and management, and modest compensation for board and committee members for meeting participation, in addition to travel expenses. EPA should consider this $40 million request as the best investment in spill prevention under this—or any other settlement – with Enbridge. Unlike previous settlements and conditions, these conditions have the potential to change business-as-usual practices in the Enbridge pipeline infrastructure.

The startup cost for these four programs is $40 million. These annual, inflation-proofed, payments of $40 million to implement these four programs should be considered as costs of doing business, similar to the other long-term programs established as settlement conditions. Further, Enbridge should consider this a small price to pay for the annual privilege to operate in the Upper Midwest of the United States.

IV. REQUEST FOR A NEUTRAL THIRD-PARTY FIDUCIARY RECIPIENT

A. Justification for commenters' request

The Enbridge Corporation and its subsidiaries have had a long time to do things right, yet its overall track record reveals much wrong, with changes or improvements made only after various subsidiary companies are caught violating the law. It can well afford – and it well deserves to pay – substantial penalties for its repeated pattern of neglect and carelessness that harms people and the environment. For these reasons, we do not trust Enbridge to handle or direct ***any*** funds from this Consent Decree.[47]

B. Request: Re-directing penalty funds

To do the most possible good, all penalties resulting from this settlement should be directed into the hands of those who have the most to gain by minimizing risk of oil spills and improving air and water quality during daily Facility operations – area residents. To do this, we request that ***all penalties and fines*** resulting from this settlement agreement, including all annual payments to support ongoing citizen involvement in improving the safety record of this refinery, should be directed to independent,

[47] A Supplemental Environmental Project (SEP) is not included as part of this proposed settlement, nor should one be, nor would we want one to be.

third-party fiduciary such as the National Fish and Wildlife Foundation, with a proven track record for receiving and responsibly managing settlement funds and penalties – and for supporting projects in communities directly harmed by the activities that led to the settlement or penalties. Most recently, NWFW was entrusted to receive $2.4 billion from the BP Deepwater Horizon disaster.

Funds would be used for any and/or all of the following explicit purposes:

a) startup funding to initiate the process of establishing an independent Lake Michigan Regional Citizens' Advisory Council and Upper Mississippi Regional Citizens' Advisory Council with key stakeholder groups;

b) startup funding to initiate the process of establishing an independent Lake Michigan Area Committee and Upper Mississippi Area Committee with key municipal stakeholders;

c) funding to support annual operations of an independent Lake Michigan Area Committee and an independent Lake Michigan Regional Citizens' Advisory Council; <u>or</u>

d) funding for local and/or regional citizens' advisory projects at the same levels and with the same goals of the organizational structures defined in the conditions set forth in (a) through (c) of this subsection.

e) funding design and implementation of an independent, annual environmental monitoring program for the Enbridge pipeline infrastructure modeled after the environmental monitoring program conducted by the Prince William Sound RCAC for the Alyeska tanker terminal with additional duties as outlined for the Independent Third Party as described in the Consent Decree. (*Funded by penalty fees and NOT by Enbridge directly*.)

V. SUMMARY

In summary, we find that Enbridge Corporation has a track record of negligence regarding operations and maintenance of its extensive pipeline infrastructure, willful safety and environmental violations, and an utter managerial disregard – bordering on contempt – for environmental and safety regulations. For these reasons, and as discussed in our comments, we ask for:

1. **Maximum penalty of $86,352,600 in this case for each barrel spilled for Line 6A, and for a maximum penalty of $7,069,700 per barrel for the Line 6B spill be assessed per each of the nine defendants;**
2. **Three additional conditions under this settlement including:**
   a. Establishment of, and $20 million annually, inflation-proofed, for implementation of, an independent Lake Michigan Regional Citizens' Advisory Council (RCAC), and a Upper Mississippi Regional Citizens' Advisory Council (RCAC) modeled after the Prince William Sound RCAC established under the Oil Pollution Act of 1990;
   b. Establishment of, and $20 million annually, inflation-proofed, for implementation of, an independent Lake Michigan Area Committee and a Upper Mississippi Area Committee, as mandated under the Oil Pollution Act of 1990; and
   c. Establishment of an independent environmental monitoring program for the Enbridge pipeline infrastructure, modeled after the environmental monitoring program conducted by the Prince William Sound RCAC for the Alyeska tanker

terminal and performing duties as Independent Third Party as outlined in Consent Decree.(***Funded by penalty fees and NOT by Enbridge directly.***); and

3. A neutral third-party fiduciary recipient – such as the National Fish and Wildlife Foundation – of *all penalties and funds* resulting from this Consent Decree for Funding for local and/or regional citizens' advisory projects at the same levels and with the same goals of the organizational structures defined in the conditions set forth in Section III.

Thank you for the opportunity to comment.

SIGNATORIES

Riki Ott, PhD, Director
ALERT, a project of Earth Island Institute
Berkeley, CA

Peggy Salazar, Director
Southeast Environmental Task Force
Chicago, Illinois

Sam Love
Dunelands Environmental Justice

Olga Bautista
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350Kishwaukee
DeKalb, Illinois

Monica Jenkins
Break Free Midwest Response Network
100 Grannies for a Livable Future
350 Kansas City (MO)
350 Louisville
350 Madison
350 Milwaukee
BIG - Blacks in Green
CARS, Citizens Acting for Rail Safety

Chicago 350
Chicagoland Oil By Rail
Circle Pines Center
Conserve Our Rural Ecosystem (CORE)
DuneCATS
Detroit Coalition Against Tar Sands (DCATS)
Earthseed
Elder Climate Action
Elgin Green Groups 350
Energy Action Coalition
First Unitarian Church of Hobart / Faith in Action Committee
FLOW - For Love Of Water
Food & Water Watch
Forest City 350
Fox Valley Citizens for Peace & Justice
Frack Free IL
Heartwood Council
IL Climate Activists
Illinois South Solutions
Immigrant Support And Assistance Center
IOWA 350
MN350
Pilsen Alliance
SAFE - Southern IL Against Fracturing our Environment
Science and Env. Health Network (SEHN)
Shawnee Forest Sentinels
Minnesota Public Interest Research Group (MPIRG)
United Church of Christ Justice and Witness Ministries
Vote-Climate.org
Women's Congress for Future Generations

To: ENRD, PUBCOMMENT-EES (ENRD)[PENRD3@ENRD.USDOJ.GOV]
Cc: [redacted]
From: Monica Jenkins
Sent: Wed 8/24/2016 7:31:05 PM
Importance: Normal
Subject: D. J. Ref. No. 90-5-1-1-10099 - Comment / ALERT et al
Received: Wed 8/24/2016 7:35:07 PM
Exhibit_01 - ALERT ET AL.pdf
Exhibit_02 - ALERT ET AL.pdf
Exhibit_03 - ALERT ET AL.pdf
Exhibit_04 - ALERT ET AL.pdf
Exhibit_05 - ALERT ET AL.pdf
Exhibit_06 - ALERT ET AL.pdf
Exhibit_07 - ALERT ET AL.pdf
Exhibit_08 - ALERT ET AL.pdf
Exhibit_09 - ALERT ET AL.pdf
Exhibit_10 - ALERT ET AL.pdf
Exhibit_11 - ALERT ET AL.pdf
FINAL 8-24 DJRefNo90-5-1-1-10099-1.pdf

Randall M. Stone, Acting Asst. Chief,

On behalf of the authors and signatories of our coalition, I respectfully submit the following formal comment with exhibits. I am attaching our Comment statement dated August 24, 2016 and the 11 referenced exhibits. All documents are also available in this linked google drive folder.

If you have questions, please feel free to call or email me and I will forward to the appropriate person of our group.

We appreciate the opportunity to submit this Comment and look forward to your response.

Sincerely,

Monica Jenkins
Break Free Midwest Response Network

Monica N. Jenkins
[redacted]

"The public policy of the State and the duty of each person is to provide and maintain a healthful environment for the benefit of this and future generations. The General Assembly shal law for the implementation and enforcement of this public policy" ~ Article XI, State of Illinois Constitution

National Transportation Safety Board
Washington, D C 20594

Pipeline Accident Brief

Accident No.:	DCA-10-FP-009
Type of System:	Crude oil transmission pipeline
Accident Type:	Pipeline damage with release
Location:	Romeoville, Illinois
Date:	September 9, 2010
Time:	11:30 a.m., central daylight time[1]
Owner/Operator:	Enbridge Energy, Limited Partnership
Fatalities/Injuries:	None
Damage/Cleanup Cost:	$46 6 million
Material Released:	Heavy crude oil
Quantity Released:	6,430 barrels (270,000 gallons)
Pipeline Pressure:	101 pounds per square inch, gauge
Maximum Operating Pressure:	619 pounds per square inch, gauge
Component Affected:	34-inch diameter steel crude oil transmission pipeline

The Accident

On September 9, 2010, at 11:30 a.m., a 34-inch-diameter pipeline (Line 6A)[2] owned and operated by Enbridge Energy, Limited Partnership (Enbridge) leaked beneath the street pavement adjacent to 717 Parkwood Avenue in the Village of Romeoville (Romeoville), Will County, Illinois, releasing about 6,430 barrels of Saskatchewan heavy crude oil.[3] Damages, including the cost of the environmental remediation, totaled about $46.6 million.

The crude oil leak occurred at an industrial park about 0.6 mile west of the Des Plaines River, and 0.9 mile west of the Chicago Sanitary and Ship Canal. The closest residential areas were about 200 yards from the spill site, which was also within populated and ecologically sensitive areas designated as high consequence areas in Title 49 *Code of Federal Regulations* (CFR) 195.450.

[1] All times are central daylight time.

[2] Line 6A is part of the Enbridge liquid pipeline system that originates in Edmonton, Alberta, Canada. The 1,900-mile US portion, known as the Lakehead System, consists of pipelines of various diameters and ages operated from a control center in Edmonton. The pipeline delivers 670,000 barrels per day of synthetic, light, medium, and heavy crude oils.

[3] The Enbridge Line 6A leak volume calculation indicated a total release of 7,752 barrels, including a supervised drain down of 1,325 barrels that did not leak from the pipeline.

Enbridge reported that the monitoring system showed no indication of a leak during the several hours before discovering the crude oil release. At 9:36 a.m. on September 9, 2010, a passerby reported a water leak near 717 Parkwood Avenue to the Romeoville Public Works Department (PWD). The PWD immediately dispatched an equipment operator to investigate the water leak. At 9:46 a.m., the equipment operator notified the PWD water superintendent that water was discharging from expansion joints and cracks in the pavement from what he believed was a leaking service line. The equipment operator closed a valve on the water service line to Northfield Block Company, a privately owned business near the leak site, stopping the water discharge. Concluding that the leak was not creating a safety hazard, he turned the valve back on to restore water service to the facility—the water flow resumed from cracks in the pavement. He recommended a water leak detection company to a Northfield Block Company representative.

About 11:30 a.m., a technician from Water Services, Inc., the water leak detection company hired by Northfield Block Company, arrived at the scene to locate the source of the leak. In addition to the leaking water, the technician observed oil discharging from beneath the pavement in the vicinity of the reported water leak.

At 12:04 p.m., the Romeoville Fire Department received a report about a gas-like odor at 719 Parkwood Avenue, the location where oil was flowing out of the ground. Firefighters were dispatched to conduct an outdoor gas odor investigation. Upon their arrival at 12:11 p.m., they observed black oil discharging from expansion joints and cracks in a 30 square foot area of an asphalt-and-concrete driveway at the entrance to the Northfield Block Company. They described a heavy flow of oil running south along the street gutter in a 4-foot wide stream that was about 6 inches deep (see figure 1). The fire department immediately notified Enbridge, and a control center operator initiated the oil pipeline shutdown at 12:29 p.m.

The released oil flowed into a storm water drainage ditch and then to a storm water management pond. Both required subsequent excavation and restoration activities to remove the oil.

Three days later, Enbridge crews excavated the area around the damaged water and crude oil pipelines. Investigators observed a 1.5-inch diameter hole on the underside of the oil pipeline directly above the leaking 6-inch diameter water pipe that crossed 5 inches beneath the Enbridge pipeline. The earthen material around the pipes contained large rocks and coarse gravel. The water pipe was severely corroded and had three large holes on top of the pipe facing the oil pipeline.

Figure 1. Aerial view of Parkwood Avenue looking southeast, September 9, 2010

Emergency Response

About 12:11 p.m., the Romeoville Fire Department reported the oil leak to the PWD. The assistant fire chief obtained the Enbridge emergency contact information from a nearby pipeline marker and notified the company of the release at 12:28 p.m.

At 12:29 p.m., the Enbridge control center initiated a shutdown of Line 6A and isolated the leak. The control center staff notified the assistant fire chief that they had initiated a shutdown and that they were contacting oil spill cleanup contractors to respond. Firefighters observed the oil flow diminish within 35 to 40 minutes.

Enbridge notified the National Response Center at 1:06 p.m., then notified the Illinois Environmental Protection Agency, the US Coast Guard, and the Illinois Emergency Management Agency.

Responding fire department units, including a hazardous materials response team, established a command post and evacuated nearby businesses. The fire and public works departments established a control point for the oil spill at the storm water management pond. Firefighters attempted to contain the oil in the gutter along Parkwood Avenue, but the release volume was too great to control with the equipment they had. Crude oil entered two storm drain inlets then flowed into a 1.5 acre storm water management pond that drains into the Des Plaines River.

Subsurface oil at the spill site accumulated under the Parkwood Avenue pavement and migrated along underground utility pipes. Some of the oil entered the sanitary sewer system via compromised piping and manhole covers, where the oil flowed into the Romeoville Waste Water Treatment Plant–South Plant. Operators diverted the contaminated influent to holding tanks and a retention basin. No oil was released from the waste water treatment plant. Responders also placed oil booms at the storm water retention pond spillway to prevent the release from entering the Des Plaines River. Enbridge spill response contractors contained the oil in the pond using boom and skimming equipment.

Enbridge, the US Environmental Protection Agency, and the Romeoville emergency responders established a unified command. Cooperating agencies included the Pipeline and Hazardous Materials Safety Administration, the Romeoville mayor, the village manager, and the police and the fire departments. Enbridge financed the clean-up operations and remedial actions.

Pipeline Information

The pipeline was constructed in 1968 of flash-welded[4] American Petroleum Institute (API) X52 steel pipe manufactured by A.O. Smith. The 34-inch-diameter pipe had a nominal wall thickness of 0.281 inches. The pipe was coated with a single wrap of 18-inch wide Polyken polyethylene tape. The tape was field applied by machine after the bare metal pipe was coated with a primer to ensure adhesion and bonding. The tape coating was damaged and disbonded (that is, the adhesive bond between the pipe and its protective polyethylene tape coating had deteriorated) in the area where the leak occurred.

The maximum operating pressure (MOP) of the pipeline segment was 619 psig. Enbridge estimated that the pipeline pressure at the time and location of the accident was 101 psig.

Several other underground pipes ran parallel to the oil pipeline, including a storm sewer, a sanitary sewer, a natural gas pipeline, and water pipes. A 6-inch-diameter ductile iron cement lined water service pipe ran perpendicular to and below the Enbridge pipeline with a separation of only 5 inches. The oil pipeline leak occurred directly above the water pipe.

[4] The longitudinal weld seam is formed by electric flash welding, a resistance welding process in which the ends are joined by heating and forging without the addition of filler metal.

Corrosion Protection

In addition to the polyethylene tape wrap on the pipeline, Enbridge operated a cathodic protection system using impressed dc electrical current rectifiers[5] to protect the line from corrosion. The nearest anode bed for the cathodic protection was located about 1.4 miles upstream of the accident location.

Section 4.3.10 of the National Association of Corrosion Engineers (NACE)[6] standard states that underground piping systems should be installed so that they are physically separated from foreign metallic structures at crossings and parallel installations and in such a way that electrical isolation can be maintained. Furthermore, since April 1970, 49 CFR 195.250 has prescribed that a minimum clearance of 12 inches must be maintained between a pipeline and any other underground structure. A reduction in this clearance is allowed only if adequate provision is made for corrosion control, which was not done at this location.

Survey Data and Leakage History

Enbridge reported that between 2000 and 2008, it did not identify any defects of concern from eight in-line inspections for corrosion, metal loss, dents, or cracks in the area where the pipeline damage was located. However, an August 2008 inspection using a magnetic flux leakage (MFL) tool[7] identified a metal object near the area of the damaged pipeline. Records indicated no history of excavation to repair or work on the pipeline at the location of the leak.

Enbridge reported that its supervisory control and data acquisition (SCADA) system, its commodity movement and tracking (CMT) system,[8] and its material balance system (MBS)[9] did not indicate any anomalies during the several hours preceding the discovery of the crude oil leak by the Water Services, Inc. technician

[5] Impressed current cathodic protection is considered more effective than galvanic cathodic protection in long pipelines. An external dc electrical power source imparts current into the soil through sacrificial metal (the anode), which corrodes instead of the protected metal.

[6] NACE is an industry organization dedicated to the study of corrosion by promoting research of new technology and trade standards and publications.

[7] Sensors on MFL inspection tools detect the leakage fields as they move through the pipeline. Pipe wall changes such as metal loss will cause some of the magnetism to leak outside of the pipe wall. MFL tool specifications describe that a tool has a 90 percent probability of identifying general metal loss that is greater than 10 percent of the wall thickness.

[8] At Enbridge, CMT is a system that performs real-time monitoring of the oil in the pipeline. Control center operators manually perform an accounting of the volumes in the pipeline every 2 hours to check for delivery volumes and potential leaks.

[9] The Enbridge MBS uses a real-time pressure transient pipeline model, which operates in parallel with the SCADA and CMT systems to compare actual and expected flows and pressures between pipeline sections.

Water Supply Pipe Crossing

The Illinois Underground Utility Facilities Damage Prevention Act mandates the use of the Joint Utility Locating Information for Excavators, Inc. (JULIE) one-call system for all excavations on pipeline right-of-ways. Will County, Illinois, began using the JULIE system in August 1974.[10]

The JULIE system requires that prior to any nonemergency excavation an excavator must do the following:

(1) Take reasonable action to become aware of the location of underground utility facilities.

(2) Plan the excavation or demolition to avoid or minimize interference with the underground utility facilities.

(3) Provide notice through the statewide one-call system not more than 14 days nor less than 48 hours in advance of the start of the operation.

(4) Provide support for existing underground utility facilities during and following the operation.

(5) Properly backfill all excavations. Utility owners or operators are required by the legislation to maintain written records of the notice.

Romeoville records indicate that the 6-inch water pipe that passed beneath Line 6A was installed in 1977. At that time, service connections were subject to the requirements of the Village of Romeoville, Illinois, Code of Ordinances.[11] The ordinance required that the application to begin proposed plumbing work shall be made to the building inspector by the plumber as agent of the property owner. Romeoville records did not identify the plumber who installed the water pipe, nor did they indicate whether JULIE or Enbridge had been notified of the project. Enbridge had no record documenting the existence of the water pipe and no record from JULIE for any excavation work at that location.

[10] In 1976, JULIE was accepted by the Illinois Commerce Commission as being compliant with the one-call notification section of Illinois General Order 185.

[11] Village of Romeoville, Illinois, Code of Ordinances, Title V, Chapter 50: Waterworks System.

Postaccident Investigation

The oil pipeline sustained a 1.5 -inch-diameter hole (see figure 2) about the 6:00 o'clock (bottom) position directly above the water pipe that crossed beneath it. The pipeline wall was thimed and deformed inward around the edges of the hole.

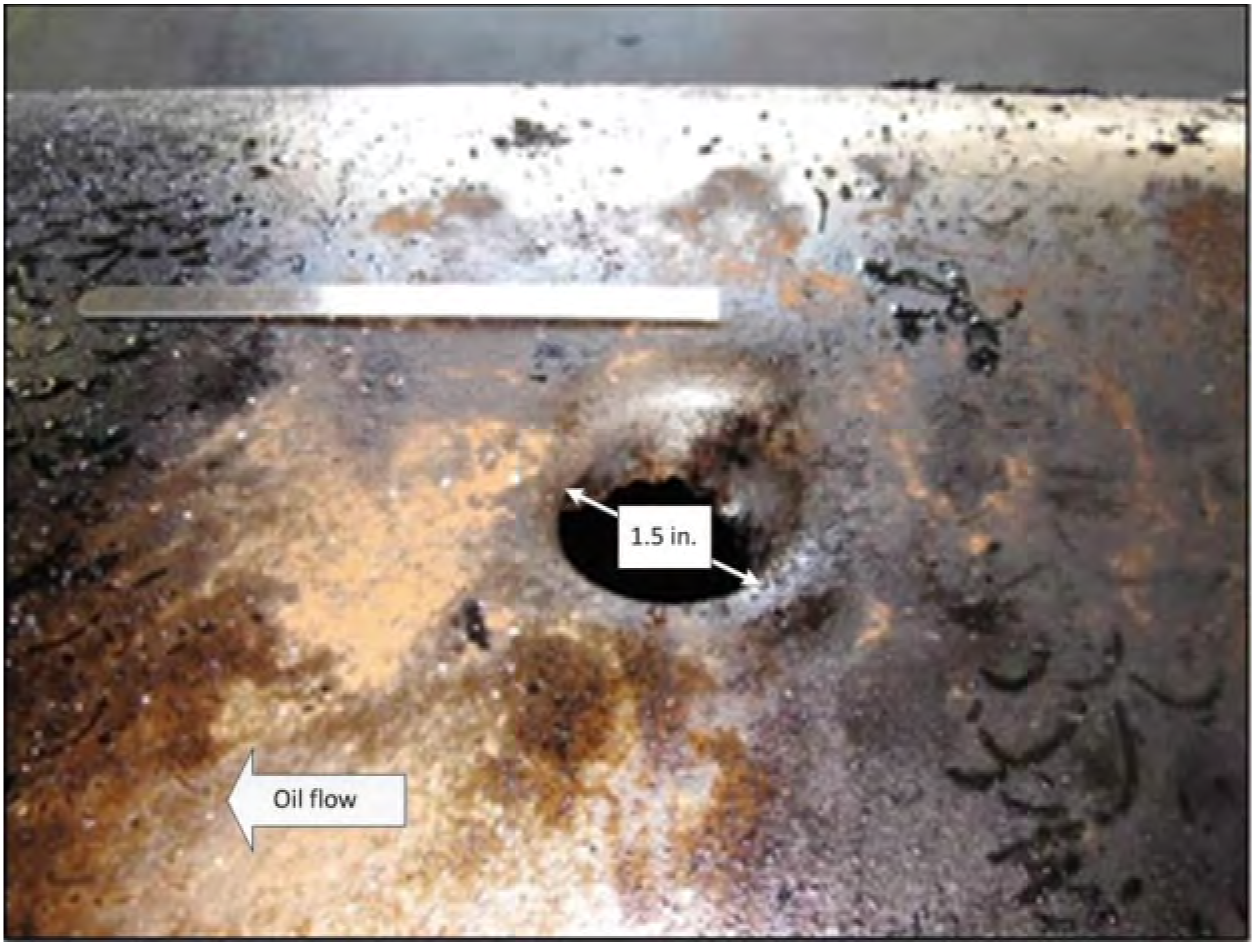


Figure 2. External view of the hole in the bottom of the 34-inch-diameter oil pipeline

The outer surface deformed inward within a diameter of about 3 inches and was visible on the interior surface of the pipe. Piles of small rocks about 0.125 inch in diameter were covered in oil and stuck to the interior surface of the pipeline.

The oil pipeline tape coating was heavily damaged in the area above the water pipe, likely from the water jetting against it. Strips of ripped and disbonded coating and tape hung down from the sides of the pipeline in the vicinity of the leak location (see figure 3).

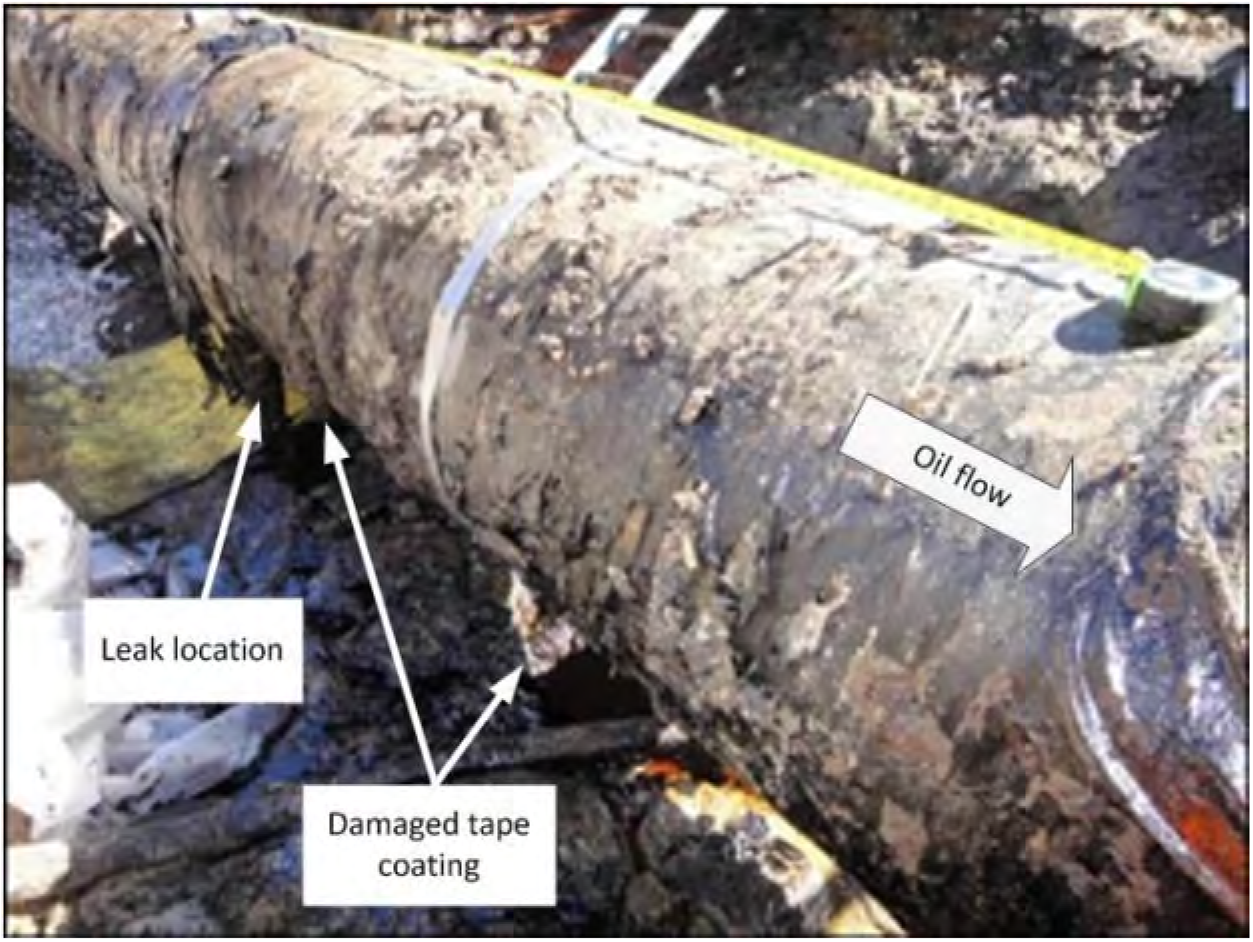


Figure 3. View of the damaged tape coating on the oil pipeline in the excavated trench

Sliding contact damage (gouging) on the outer surface of the oil pipeline was observed within 24 inches downstream from where the water pipe passed under the pipeline (see figure 4). Deformed pipe wall material protruded from the surface of many of the marks, most likely caused by digging tool strikes that occurred during the excavation work when the water pipe was installed.

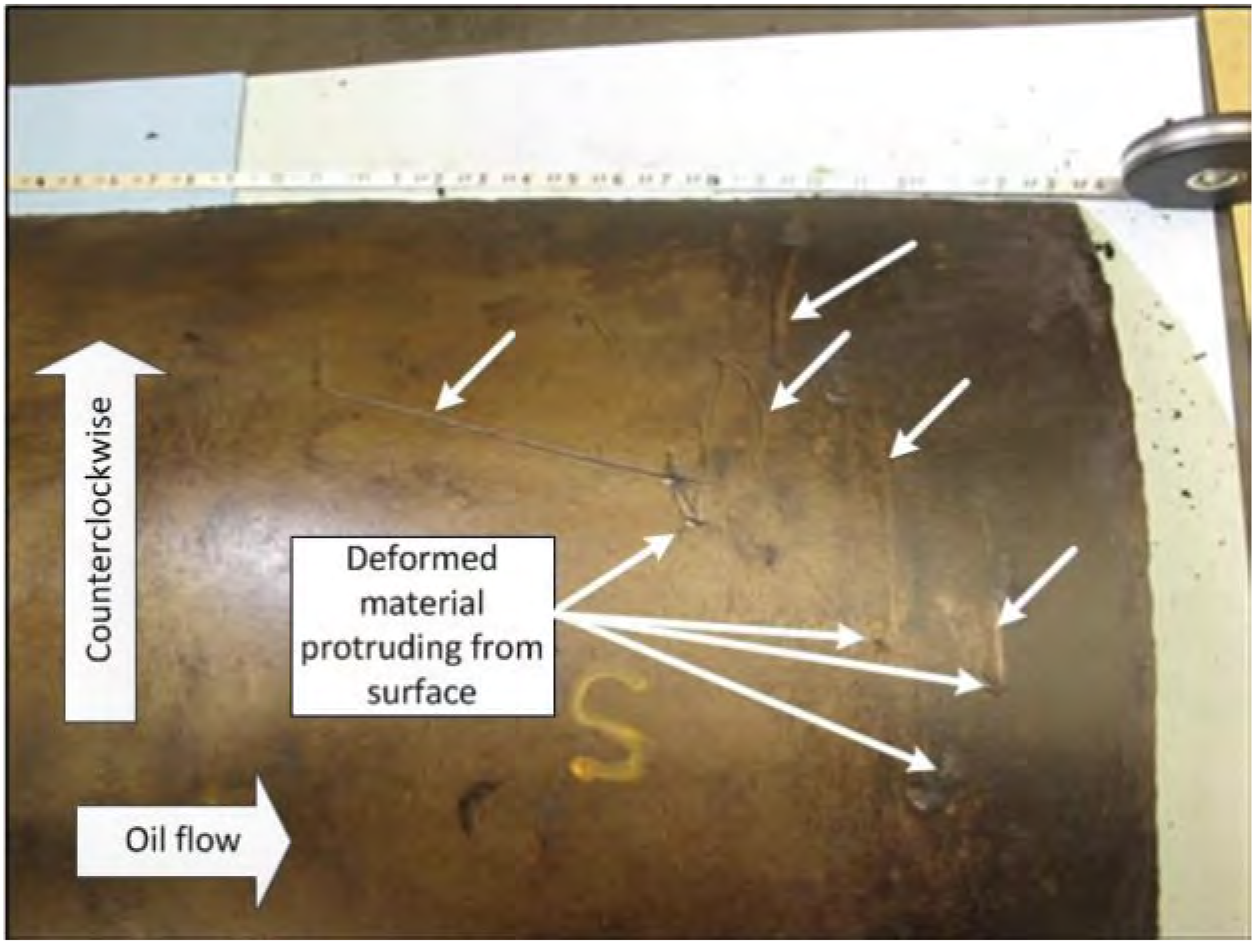


Figure 4. Sliding contact gouges (individual arrows) and deformed material on the outer surface of the oil pipeline near the water pipe intersection

The water pipe was corroded and had three large holes through the pipe wall and concrete liner on the upper half of the pipe in the immediate area directly below the oil pipeline (see figure 5). The largest hole measured 5.1 inches around the circumference and had an irregular shape. The metal edges of the holes were rounded and oxidized. A corrosion pitted area extended about 16 inches upstream and downstream along the top and sides of the pipe from the center of the largest hole. The bottom of the pipe as well as the entire circumference upstream and downstream beyond the corroded area did not exhibit significant corrosion.

Figure 5. Large holes and corrosion damage on the top of the 6-inch-diameter water pipe

Trench Conditions

Upon excavating the damaged pipes, investigators observed large rocks and coarse gravel between the bottom of and in contact with the oil pipeline and the top of the water pipe. The NTSB Materials Laboratory examined six large rocks that had been firmly wedged between the oil pipeline and the water pipe. Some were stained black, consistent with deposited oil. The rock shapes were compared to the shape of the hole and inward deformation in the oil pipe; however, no conclusive match was found.

The trench backfill along the oil pipeline north and south of the leak location was sand, in contrast to the large rocks that were used as the backfill in the vicinity of the water pipe crossing.

Sequence and Mechanism of the Pipeline Hole Formation

Holes were observed in the water pipe and the oil pipeline. Most likely, the large holes in the water pipe developed first due to stray current corrosion, and the hole in the oil pipeline developed due to erosion from water jet impingement on the oil pipeline.

The oil pipeline is cathodically protected with an impressed current system. A metallic object in close proximity to the oil pipeline, such as the water pipe, can disrupt the electric current flow and cause the metallic object to corrode, which is likely what caused the heavy local corrosion on the water pipe. Being only 5 inches away, the water pipe was close enough to disrupt the cathodic protection currents on the oil pipeline.

The gravel fill to the west of the oil pipeline was added after a sanitary sewer repair the previous winter and remained exposed at the surface until an asphalt patch was applied in the spring.

According to an article published by the Ductile Iron Pipe Research Association,[12] when a ductile iron pipe crosses a cathodically protected pipe, the ductile iron pipe should be encased with polyethylene for a 20-foot distance in each direction from the nearby cathodically protected pipe. Alternatively, a sacrificial anode could be attached to the water pipe to discharge the current from the anode instead of from the water pipe back to the oil pipeline. Contrary to these recommended practices, the water pipe was not provided either protection method.

Although the oil pipeline was installed with a protective coating, NTSB investigators determined the coating was most likely damaged during the water pipe installation, as evidenced by the gouges observed on the oil pipeline. The damaged oil pipeline coating provided a pathway for stray current to lead to extensive, deep corrosion on the upper side of the water pipe. Eventually, the ductile iron water pipe was so degraded that the concrete liner was unable to contain the water pressure.

[12] Richard. W. Bonds, "Stray Current Effects on Ductile Iron Pipe," Ductile Iron Pipe Research Association, Birmingham, Alabama, (1997)

The holes in the water pipe became larger from the jetting water flow The high-velocity, spraying water with suspended sand and small gravel began striking the oil pipeline until a through-wall hole developed.

Impact of the Crude Oil Release

Community

On the day of the accident, the fire department evacuated 50 persons from 11 nearby businesses. Twenty-three area businesses were closed for 1 to 9 days. The PWD temporarily plugged one sanitary sewer line, which disrupted several nearby businesses for a day.

Environment

The EPA responded to the scene on September 9, 2010, to oversee removal of oil-contaminated soil and pavement, and the cleanup and restoration of the sanitary and storm drain systems, storm water management pond, and waste water treatment plant. The EPA also supervised surface water sampling, area air monitoring, and the installation and sampling of a network of 31 groundwater monitoring wells. On October 28, 2010, the EPA transferred oversight of long-term monitoring and cleanup of contaminated ground water to the Illinois EPA.

Enbridge recovered 694,000 gallons of oil and water mixture. An additional 55,650 gallons of oil were pumped from the isolated pipeline segment. The EPA also removed about 1.5 million gallons of hazardous waste, 1 million gallons of treated water from the retention pond, 4.4 million gallons of treated sewage lagoon water, and 15,000 cubic yards of contaminated soils. A wildlife response center treated and released 141 turtles and frogs, while another 32 animals were found deceased in the field.

Costs

Enbridge's expenses related to the release of crude oil from Line 6A, including environmental remediation, totaled $46,617,000. Federal response and oversight costs were $550,000.

Postaccident Actions Involving Hazardous Liquid Pipelines

On January 3, 2012, pipeline leak detection capability was addressed in the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011,[13] Section 8 This Act requires the US Secretary of Transportation to submit to Congress a report on leak detection systems used by operators of hazardous liquid pipelines. The report must include an analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and of what can be done to foster development of better technologies. The report must also address the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks. The Act requires the US Department of Transportation (DOT) to

[13] Public Law 112-90, January 3, 2012.

promulgate regulations mandating implementation of the technology if the DOT finds that it is practicable to establish such standards for the capability of leak detection systems to detect leaks.

On July 10, 2012, the NTSB adopted its report addressing the July 25, 2010, rupture of a 30-inch-diameter Enbridge pipeline that released more than 843,000 gallons crude oil into a wetland and the Kalamazoo River in Marshall, Michigan.[14] The NTSB issued safety recommendations to the US Secretary of Transportation, the Pipeline and Hazardous Materials Safety Administration, Enbridge Incorporated, the American Petroleum Institute, the Pipeline Research Council International, the International Association of Fire Chiefs, and the National Emergency Number Association. The NTSB expressed concern about the failure of the Enbridge control center staff to recognize abnormal conditions that might indicate a pipeline leak or rupture and issued recommendations to Enbridge to improve leak detection.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the Enbridge Energy, Limited Partnership oil pipeline leak and crude oil release near the Des Plaines River in Romeoville, Illinois, on September 9, 2010, was erosion caused by water jet impingement from a leaking 6-inch diameter water pipe 5 inches below the oil pipeline.

Contributing to the accident was the interruption of the cathodic protection currents by the close proximity of the improperly installed water pipe.

Adopted: September 30, 2013

[14] National Transportation Safety Board, *Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010*, PAR-12/01 (Washington, D C: National Transportation Safety Board, 2012).

Enbridge Line 61 Pipeline Construction Effects on Farmers in LaSalle County

Enbridge Energy won eminent domain powers from Illinois in 2007 to construct Line 61, which is actually 2 pipelines 454 miles in length connecting terminals in Superior, Wisconsin to Flanagan, near Pontiac, Illinois. One pipeline carries Alberta bitumen (tar sands oil) south and the other pipeline carries back north the diluent chemicals used to thin the heavy tar sands in the pipeline. Line 61 was constructed in 2008-2009, over five years ago. The Flanagan terminal is now being connected to Cushing, Oklahoma and subsequently the Gulf Coast refineries and ports. Tar sands are, or will soon be, able to flow from Alberta, Canada to the Gulf Coast via Illinois. This has affected large areas of prime agricultural land, some of the richest and most productive in the United States.

The LaSalle County Farm Bureau sent survey forms to 75 land owners in LaSalle County, Illinois, in March, 2014, to learn what effects Line 61 had on growers in the county. The mailing list was taken from the 2006 Enbridge filing for eminent domain powers with the Illinois Commerce Commission. This list was not a complete representation of affected parties. It had several drawbacks including:

some land had changed hands over the last 8 years, either through sale or inheritance, and some owners had probably moved, so not all current landowners with pipeline easements received a survey,

the list did not include people who own land adjacent to the right of way, who also could have been affected by pipeline activities,

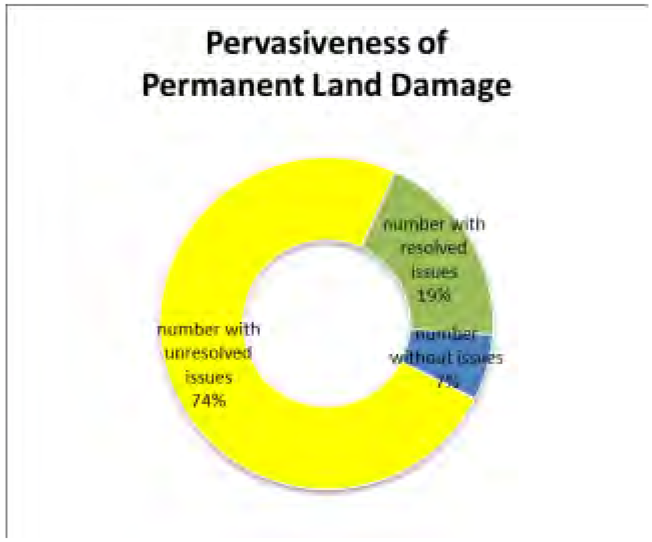
the list was culled for addresses outside LaSalle County, so owners who own land in the county but live elsewhere did not receive an opportunity to participate, and

most importantly, it did not include farm operators who lease land (though owners were asked to pass the survey along to their tenants if they wished)

Using this mailing list was the most expedient way to quickly gather the first round of data on the effects of this pipeline. Further delay would have put us into planting time for the 2014 corn and soybean crops, potentially reducing participation. But we have to recognize that the survey went to perhaps only a small subset of the people affected by this pipeline in LaSalle County.

From the 75 surveys mailed out we got 31 responses, which is a good response rate for this kind of informational survey (41% made the effort to respond, paying return postage themselves). There were both positive and negative responses, but the theme was resoundingly negative regarding the pipeline's effects on growers.

Of those responding, only 2 said there were no issues on their land caused by the pipeline construction. The other 94% had problems. Only 21% of those problems have been resolved, the other 79% of respondents with problems still have problems.

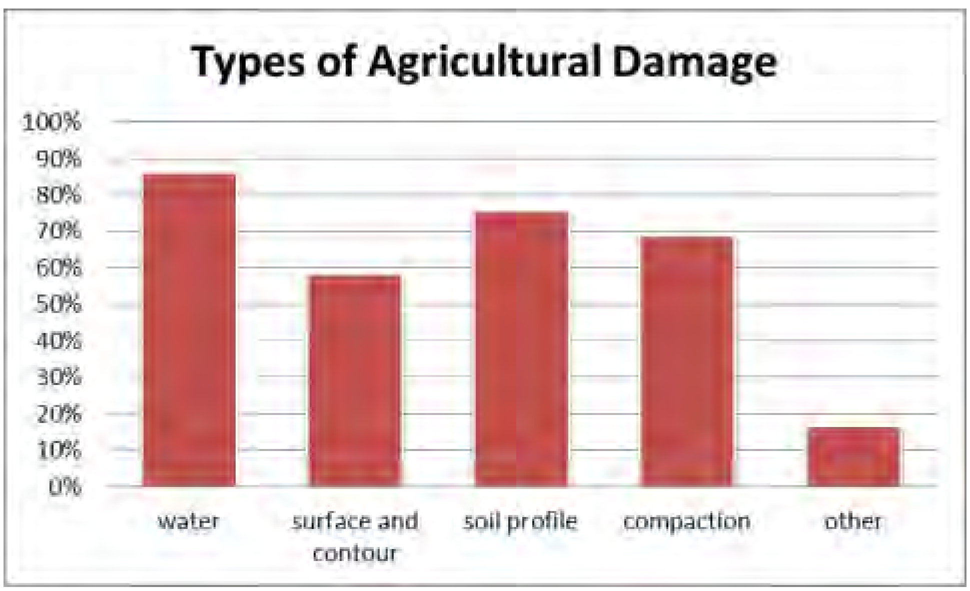


At this point, 5 years after the completion of construction and remediation, any remaining effects can be considered long-term. Almost three-quarters of affected growers appear to be suffering some form of long-term damage. To sum up, with a couple complimentary exceptions, typical comments included:

> "the pipeline was a nightmare"
> "they had no concern whatsoever for the land"
> "they had total disregard for existing tile"
> "they tore the farm up"

Types of Damage

The types of issues farmers and land owners are experiencing range from drainage problems to soil profile (e.g.: intermixing subsoil and topsoil) and compaction.



Most respondents have more than one issue to deal with. The most prevalent is water related, with 86% of those with damage having problems with drainage resulting from the Enbridge activities. This may be fixable. Intermixing subsoil (reducing soil productivity and affecting drainage patterns) was second most prevalent, and ongoing problems from compaction (crushed soil structure reducing the space for air and water and making root penetration more difficult) are being experienced by more than two-thirds of those dealing with agricultural damage from the pipeline. Compaction and subsoil intermixing may be permanent forms of damage. Other problems include destroyed waterways, water pumped onto fields, removed property markers, and buried lumber from skids.

While a few owners reported that Enbridge put in new tile and made other remediation efforts that rectified their problems, others report:

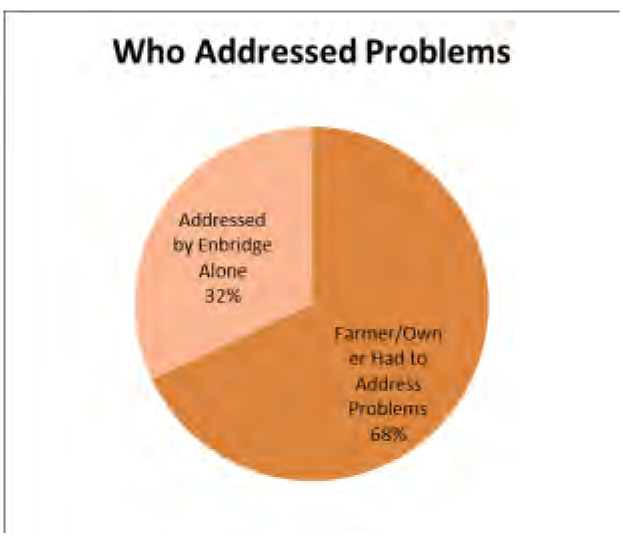
> "Drainage is terrible in this area over the pipeline!"
> "Compaction! Frost or rippers cannot go deep enough to undo the affected areas"
> "Still having issues. Enbridge said they would address issues but just passed from person to person, never put good faith effort to resolve issues."
> "Hard to say how many hours spent on this. Ground condition and water drainage are still bad."

Effects of Problems

One of the untold stories with these pipeline activities is the amount of time it takes from productivity. Farming is a business. Like any business, staff productivity is paramount. If you sap the productivity of the people in the business, it hurts the business. One respondent said:

> *"Compaction still a problem. Been working on it for years, hours too numerous to count… Deep tillage in mud is not very effective* [when they did remediation]*, not in compliance with Agricultural Mitigation Agreement. They worked in very wet conditions, hauled pipeline across ground before the topsoil was removed. Their contractor had never seen the Ag Mitigation Agreement and did not follow it. Needed daily monitoring."*

It's not only before and during construction that farmers and land owners need to spend a lot of time monitoring and working on construction issues, but it appears they deal with the effects for years after all the construction crews have gone. Many have been taking care of these problems themselves either partially or completely. Of those for whom issues have been addressed at least somewhat, 68% have had to address the issues themselves. Only 32% were able to rely on Enbridge for all the work done so far. And recall that only 21% of the respondents have had their issues resolved. For the other 79%, the damage seems long-term and time consuming. Asked separately about the expense (as opposed to the effort), 38% of respondents said they have had to bear some or all of the cost of remediation themselves.



The number of man-hours spent dealing with these issues has a cost. A farmer's time is worth something, just as any business owner's time has value. Those hours have been uncompensated. This is another form of taking, in addition to the land rights and crop revenues, but for most growers it has been a one-sided exchange.

If the average farmer only needed to spend 120 hours on this over his lifetime, a very low estimate, and only 75 farm "CEO's" are affected in LaSalle County (it actually affects both owners and tenants as well perhaps as adjoining owners and tenants), at an hourly rate of $100 per business owner that would represent nearly $1,000,000 in labor and management taking for this pipeline in this county alone. Statewide, if LaSalle County represents only 36 of the 125 miles traversed by Line 61 in Illinois, Enbridge might have absorbed $3.5 million in management time from farming businesses.

Production Losses

Revenue losses from yield reductions also remain a problem. When drainage, compaction, soil profile and other problems exist, they can affect the amount of grain the ground yields. These effects can be hard to document, particularly when the pipeline follows a diagonal path across fields. Most yield monitors can't capture or report data in ways that allow farmers to document yields from a diagonal strip across a field, even though the operators can see it on their monitors as they harvest.

There were many reports of yield loss, evidencing its pervasiveness. One farmer said "yield monitors [in the harvester] show 25-50 bushel-per-acre loss on the easement [in 2013]." Others said:

> "Some spots are not yielding at this time"
> "Yield reductions have occurred for several years after construction"
> "Yields are reduced 20 bushels for corn where the pipe is in the ground"
> "The yields over the pipeline have been 40-50 bushel less per acre for corn and 5-10 bushel less per acre for soybeans by the yield monitor on the combine"

Farmers were offered a settlement for a short period of reduced yields, but yield losses appear to be permanent. If these reports are representative, they indicate yield losses of about 16% of county average yields for 2013. The economic loss from 16% yield reductions in corn is $150 per acre at current prices (current to when the losses were reported). This especially hurts now, at a time when grain farms are operating at breakeven levels.

How widespread could this effect be? Soil was affected across the entire length and width of their construction activities. The trenching occurred within a 60-foot wide easement and heavy equipment traversals occurred there as well as across the additional 90-foot wide construction easement. The pipeline traversed the length of LaSalle County for 36 miles on a diagonal zig-zag path. That would take up perhaps 655 acres in LaSalle County. If average revenue losses are $150 per acre, this pipeline would be reducing production by at least $100,000 per year in the county. That is, if the effects are confined strictly to where the easements lie. Drainage and compaction issues, for example, can affect water retention and drainage in adjoining ground. So, these estimates are probably low.

This could have an effect on farmers' production history, which is major factor in insurance coverages, rents, and potentially land prices. With new farm bills, farmers may have to report production to re-establish yield histories as a basis for crop insurance claims. If their production histories suffer, their insurance coverage will be diminished. The effects will be lasting. If it lasts in perpetuity, at a common capitalization rate of 3.5% for farm land, this 16% yield reduction alone would contribute a $4200 per acre loss to land value in addition to the other direct and indirect grower costs associated with the pipeline. In LaSalle County that would total about $2,800,000 in agricultural value lost.

The pipeline route traversed perhaps 125 miles from Wisconsin to the Flanagan terminal. Using these estimates, owners in the state lost almost $10 million in agricultural value and $340,000 per year in production from this one pipeline right of way. Again, these estimates only consider the ground directly under easement, not any adjoining parcels that were probably affected.

Direct Costs to Growers

Many growers had to put extra work into their fields where the pipeline work had effect. At a given farm this might have included:

Ripping and subsoiling work
Additional surface conditioning (e.g.: breaking up subsoil clods at the surface)
Surface re-contouring and smoothing
Tiling, waterway excavation, and other drainage work
Additional fertilizer and lime application
Additional weed and pest control measures
Rock picking and scrap lumber removal
Additional cover crop establishment and care

For example, a farmer may have had to spend 10 hours picking rock and scrap lumber before planting. He may have had to make 6 passes v-ripping and discing to remediate surface conditions and contours. Using the custom rate survey from Iowa State University, that farmer would have invested about $154 per acre in direct cost related to the impact the pipeline had on him.

The survey form was not designed to capture this level of detail, but enough respondents indicated that they had to perform remediation work themselves that it is a significant factor. On those farms where the issues were addressed, 68% of operators had to remediate issues themselves. If the average cost of remediation so far was $154 per acre, that would be over $100,000 in uncompensated remediation costs taken from growers in LaSalle County without considering the much larger costs for eventual tiling, waterway and drainage work.

Loss of Rights and Opportunity Costs

In addition to direct costs and loss of production value, Enbridge took away ownership rights such as opportunities for alternative use and development. These losses of rights and opportunities also have value. This affects not only the ground under easement but also the surrounding area. People may not want to build a house next to the pipeline, for example. Windmills can't be constructed along the easements, and there are restrictions and risks associated with crossing the pipeline with any appurtenances to other operations.

Furthermore, farmers also have lost the right to unrestricted normal operations around the pipeline right of way. This affects not only farming, causing farmers to potentially change the way they do tillage and cultivation, but it also can cause growers to suffer additional damaging impact from other entities with easements, for utilities or transportation as two examples. One farm owner suffered double the damage from heavy equipment traffic along an electric utility easement because the utility refused to cross the pipeline right of way, re-routing construction operations to avoid it. The Enbridge easement caused this electric utility to traverse across his fields to reach a neighbor from the west rather than taking a shorter route from the east that would have limited the impact to only the neighbor's field.

Still more, none of this captures the increased risk to operations and environmental hazards from the pipeline. Supervisory burdens increase when petroleum company representatives must approve plans or schedule representatives to be on site during work. There are added concerns about drainage work on the easements, for example – farmers may be concerned about trenching or excavating in the area to fix agricultural problems. There is also the risk that any leaks or spills could ruin the land, ruin the aquifer, and cause health problems in the area.

Enbridge Responsiveness

People are generally dissatisfied with Enbridge's response to their concerns. One-fifth (21%) reported being extremely dissatisfied with Enbridge's responsiveness to their problems, and nearly half (43%) were generally dissatisfied. Only 25% (7 respondents – not everyone completed this portion) were satisfied at all.

It is almost the same for the *results* of Enbridge's response: 43% were somewhat or very dissatisfied with the results they got from any remediation while only 21% were at least somewhat satisfied with the results.

Looking Ahead

Asked if they were in favor of another pipeline, only 4 owners said they are It's notable that those appear to be land owners and not tenants. In opposition were 68% of respondents, and, showing strength of feeling, half of all respondents (50%) indicated they "detest the idea" of a new pipeline.

This was a first time experience for most of these people. Line 61 blazed a new trail for oil pipelines outside of established routes closer to the Chicago area, where the Midwest refineries and petroleum processors are. People in LaSalle County did not know what to expect in 2008. Now they do. Those affected are strongly opposed to new pipelines. They have not been "made whole" from the last one and will be dealing with its effects for a long time.

Some of their forward-looking comments include (each from a different person):

> "Pipelines should follow easements along state and interstate highways. It is not right to take private property"

"It is odd they have no trouble getting a pipeline here when they cannot build the Keystone pipeline in states that are barren"
"Would rather not go through the mess and trouble again"
"We hope the Farm Bureau will take a stand opposing pipeline expansion"
"This is a company that makes $1 billion in pre-tax profit every year. Why does it need eminent domain? The 2006 ICC filing claimed this pipeline was for Illinois residents. Why did they connect it to the Gulf? They claim it creates jobs. I have talked to no one from Illinois who ever worked for Enbridge. Pattern of misrepresentation"

Extent of the Problem

There are many pipelines in LaSalle County, of which Enbridge Line 61 is just one. Looking at the map at right, there are at least 12 major pipelines crossing the county. This shows the extent of damage done to farmers and field productivity so far.

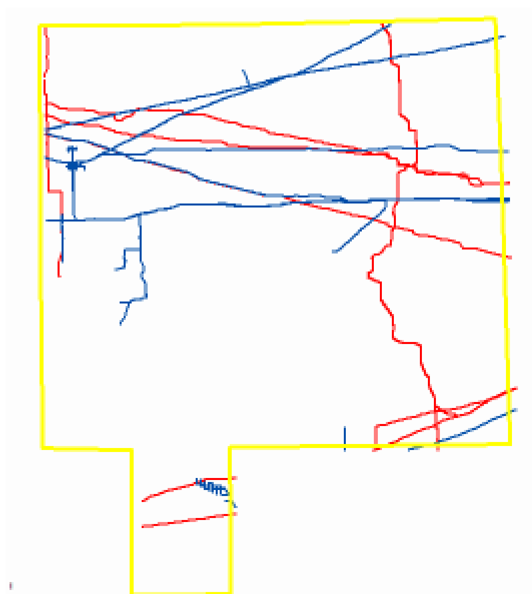


Figure 1 Oil & Gas Pipelines in LaSalle County, IL
Source: National Pipeline Mapping System - www npms phmsa dot gov

If you believe that pipeline construction activity creates jobs, then it also means these effects destroyed jobs. If politicians and profit-oriented companies can apply a multiplier to equate construction spending to jobs (which last a year) then the same multiplier would show hundreds of jobs lost in Illinois from the adverse effects of Line 61.

Looking at a national map, Plains states like South Dakota and Nebraska have comparatively fewer pipelines. This is surprising in light of the fact much of the petroleum source is in Alberta and the destination appears to be directly south of these states in Texas and Oklahoma.

Figure 2: Source: Theodora.com

Summary

Damage to agricultural land in LaSalle County from Enbridge Line 61 construction activities is prevalent, with 94% of respondents reporting some kind of agricultural problem as a result of Enbridge's new pipeline.

The damage appears permanent. More than 5 years after "remediation" 79% of the problems still exist. Most growers are experiencing drainage issues, soil profile problems, and surface issues as a result of Enbridge's pipeline.

Enbridge has not been responsive enough to these problems, and their remediation efforts have been inadequate: 68% of growers who addressed issues caused by Enbridge have had to address the issues themselves. Almost half are dissatisfied, and over 20% of respondents are **extremely** dissatisfied with Enbridge's responsiveness to their problems. Where Enbridge *has* responded, 43% are dissatisfied with the results they got.

The pipeline has been expensive to land owners and operators. Large losses of production value are being experienced, the productivity of land and labor have been diminished, and large amounts of precious time have been taken. Line 61 alone has cost land owners in LaSalle County and Illinois millions in direct and indirect costs:

Cost estimates	**LaSalle**	**IL**
Lost production value	$ 2,800,000	$ 9,500,000
Managerial Time	$ 1,000,000	$ 3,500,000
Direct Cost	?	?
Annual Yield Loss	$ 100,000	$ 350,000
Jobs lost	?	?

For Line 61, these losses appear to have been insufficiently compensated.

Looking ahead, almost nobody wants another pipeline and the vast majority are adamantly against it. Problems need to be fixed. Future pipelines need to take more care and be under closer supervision, and pipeline companies should make more fair and adequate compensation for their takings.

What's Fair

Land Owners AND tenants should be made whole – it is not incumbent on the unlucky individuals in the path of a pipeline to bear the cost and loss of rights in order to enable a private enterprise to make billions in profits. If they are left with no say about the pipeline route, growers should at least receive full reparations for their time, loss of property rights, economic losses and other damages

Fix all existing problems immediately. Soil intermixing probably cannot be fixed, and deep compaction may not be reparable, but other issues can still be remediated. There should be a coordinated effort to remediate 100% of the pipeline path including:

- Comprehensive tile and other drainage solutions offered to every farmer in the easement route – it is most appropriate for Enbridge to be responsible for all subsoil work on its easements so farmers are not burdened with the responsibility for understanding the location and procedures involving pipelines and the stress of incurring the risk of tile and excavation work where Enbridge put pipe
- More effective compaction relief beyond ripping the top layers of soil, perhaps to include:
  - Study taking the easement land out of row crop production for some period and plant with deep rooted plants to break deep compaction layers where sub-soiling equipment can't reach, with yield and/or market rate rent settlement paid to farmers for the losses during this period
- Compensation for owner/operator time and labor in remediation done so far
- Offer re-contouring where necessary to fix surface drainage problems and irregular ground shapes

A theme heard loud and clear from LaSalle County farmers is: No More Pipelines in Prime Farmland – put them in unproductive areas like deserts or along roads. Routing should be discussed openly with all affected parties, not unveiled after back room negotiations.

If pipelines must cross productive farmland, compensation must be fair and include fair exchange of value for, at a minimum:

Full land value for loss of rights and impact on future operations (no future building, no wind power, no trellis-based crops, etc. and restrictions on normal farming activities like tiling, waterway excavation, post installation, etc, affect the whole farm and not just one strip of land, which may be compensable with the full value of the strip of land)
At least $12,000 per land owner for time taking and impact on the business (time to monitor and manage the whole project lifecycle, especially when contractors have never heard of an Agriculture Impact Mitigation Agreement, the land owner has a lot of work to do, and after the project is completed there is even more work to do)
At least $4200 per acre for financial impairment from permanent productivity losses (a few years of crop damage is insufficient – the evidence shows that damage is permanent)
Full custom rate payment for any and all remediation activities performed at the discretion of the grower, including subsoiling, surface conditioning, contouring, rock and scrap picking, etc.
Complete pattern tile work not only on the permanent and construction easements but also in adjoining areas that drain onto or away from the easement – to be done <u>after</u> the trench is filled and other remediation work done (so it's not crushed again)
Complete waterway excavation, tile, and cover crop where affected
Reimbursement for additional inputs, including lime, fertilizer, herbicide and pest management

Any new pipeline should offer to follow triple-stacking procedures to remove the topsoil and keep it separate from the 2 distinct layers of subsoil in our area. All 3 layers should be kept separate at all times, including when it is being replaced. There was clearly not enough care taken in this aspect last time.

If there is a next time, there should be someone independent of the pipeline company with authority to stop construction activities if the Agriculture Impact Mitigation Agreement is not being followed. Once the topsoil and subsoil are mixed it is too late to fix. The timing of soil removal and replacement should be more appropriate, not when it is too wet during or after precipitation events. Doing subsoil remediation in saturated conditions may be not only pointless but could worsen the problems. Inadequate or improper tile work sometimes does not show itself for one or more years.

Author: Scott Cleave, manager of Cleave Farms

Addendum – Sample Images of Problems

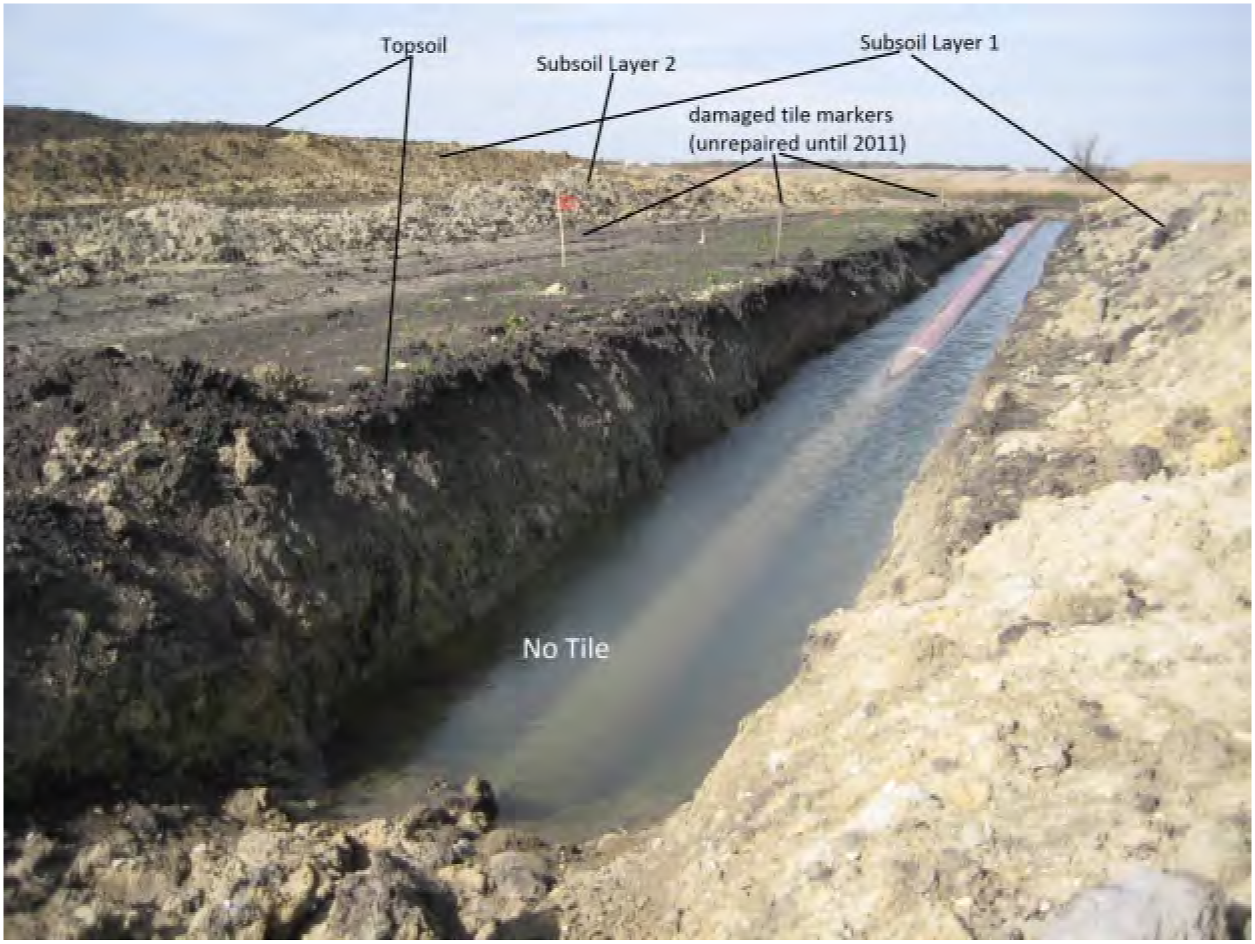


Figure 3 Cleave Farms Drainage systems destroyed, new tile either nonexistent or crushed on backfill Cl eave Farms manager documented, emailed and called for 2+ years to get a response (80+ hours). Subsoil intermixing irreparable.

Figure 4: Unnamed farm in northern LaSalle County. Subsoil layers and topsoil intermixed on replacement. No tile or tile damaged and not functioning


NEW HOLLAND
ACCESS
ROAD

Figure 5: working in wet, saturated soil conditions. Note the 2 piles of subsoil

Figure 6 Note the subsoil on ground and tires after ripping to 'relieve' compaction Soil was intermixed irreparable, compaction possibly made worse by working in saturated conditions

Figure 7: Tile damaged, water courses changed (sidewall compaction, channel change, ...). Enbridge knew there was tile there. Tile not repaired, new tile over pipe crushed on backfill of trench.

Samples of crop damage from drainage, compaction, and soil profile problems

U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

1200 New Jersey Ave., SE
Washington, DC 20590

AUG 17 2010

Mr. Terry McGill
President
Enbridge Energy Partners, L.P.
[redacted]

Re: CPF No. 3-2008-5011

Dear Mr. McGill:

Enclosed please find the Final Order issued in the above-referenced case. It makes findings of violation, assesses a civil penalty of $2,405,000, and specifies actions that must be taken by Enbridge to comply with the pipeline safety regulations. The actions required are in addition to and do not waive any requirements that apply to Enbridge's pipeline system under 49 C.F.R. Part 195, under any other order issued to Enbridge under authority of 49 U.S.C. § 60101 et seq., or under any other provision of Federal or State law.

The penalty payment terms are set forth in the Final Order. When the civil penalty has been paid and the terms of the compliance order completed, as determined by the Director, Central Region, this enforcement action will be closed. Service of the Final Order by certified mail is deemed effective upon the date of mailing, or as otherwise provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. David Barrett, Director, Central Region, PHMSA
Mr. Glenn M. Jones, Counsel for Enbridge Energy Partners, L.P.
Fulbright & Jaworski LLP, [redacted]

CERTIFIED MAIL – RETURN RECEIPT REQUESTED [7009 1410 0000 2472 2810]

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
Enbridge Energy Partners, L.P.,	)	**CPF No. 3-2008-5011**
Respondent.	)	

FINAL ORDER

On November 28, 2007, pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), and the Minnesota Office of Pipeline Safety initiated an investigation of an accident that occurred on a crude oil pipeline owned and operated by Enbridge Energy Partners, L.P. (Enbridge or Respondent), near Clearbrook, Minnesota. Respondent is a subsidiary of Enbridge Inc., a Canadian company, which owns and operates more than 8,500 miles of hazardous liquid and natural gas pipelines.[1]

The pipeline where the accident occurred is part of Enbridge's 3,500-mile Lakehead System in the Midwestern United States. The accident happened when Enbridge attempted to complete a repair of a longitudinal seam leak by installing a new 11-foot section of pipe. One of the couplings used to join the new section of pipe slipped during restart of the line, allowing the release of crude oil that formed a flammable cloud. An open flame heater positioned at the edge of the excavation ignited the cloud resulting in a fire that caused the deaths of two Enbridge employees as well as property damage to the pipeline and construction equipment.

As a result of the investigation, the Director, Central Region, OPS (Director), issued to Respondent, by letter dated October 1, 2008, a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Enbridge had committed violations of 49 C.F.R. Part 195 and proposed a civil penalty of $2,405,000 for the alleged violations. The Notice also proposed ordering Respondent to take certain measures to correct the alleged violations.

After requesting and receiving an extension of time, Enbridge responded to the Notice by letter dated November 26, 2008 (Response). Respondent stated that it did not intend to contest the merits of the allegations, but sought a reduction of the proposed civil penalty and modification of the proposed compliance terms to the extent such terms were completed. Respondent also

[1] Respondent files annual reports with PHMSA under the name Enbridge Energy, Limited Partnership, which is a subsidiary of Enbridge Energy Partners, L.P.

requested a hearing. Prior to the hearing, by letter dated December 1, 2009, Enbridge submitted information regarding corrective action it had taken.

In accordance with 49 C.F.R. § 190.211, a hearing was held on December 4, 2009, in Kansas City, Missouri, with an attorney from the Office of Chief Counsel, PHMSA, presiding. Enbridge provided a transcript of the hearing for inclusion in the record. After the hearing, Respondent provided a closing memorandum dated January 8, 2010 (Brief). Although Enbridge had stated in its Response that it did not intend to contest the violations, the company contested many of them in its Brief, and sought closure of the proposed compliance terms and a reduction of the proposed civil penalty.

PHMSA has reviewed the evidence in the record in light of the allegations of violation as well as Enbridge's assertions, and has determined that Respondent committed certain violations of the pipeline safety regulations as set forth below in the Findings of Violation section. In the Assessment of Penalty section, PHMSA has determined that Enbridge is liable for civil penalties totaling $2,405,000 for the violations. In the Compliance Order section, PHMSA has ordered Enbridge to take corrective action to remediate the violations, including revising and implementing procedures for using certain couplings, anchoring its pipeline during repairs, reviewing work performed by personnel, pressurizing a pipeline under repair, qualifying personnel to install the couplings, and training personnel.

FINDINGS OF VIOLATION

The Notice alleged that Respondent committed eight violations of 49 C.F.R. Part 195, as follows:

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 195.402(a), which states:

> **§ 195.402 Procedural manual for operations, maintenance, and emergencies.**
> (a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies . . . .

The Notice alleged that Respondent violated § 195.402(a) by failing to follow its written procedures for the use of Weld+Ends couplings during a pipe replacement project on its 34-inch crude oil pipeline (Line 3).[2] Specifically, the Notice alleged that Respondent failed to follow Enbridge Procedure 06-03-13, "PLIDCO Weld+Ends Couplings," which required the company to tighten all clamp screws evenly around the pipe and to use the torque specifications listed in the procedure. The Notice alleged that prior to the installation of the Weld+Ends couplings at Mile Post (MP) 912 on November 28, 2007, Enbridge personnel had removed approximately one half of the clamp screws on the couplings, a practice not permitted by the installation procedures.

[2] Weld+Ends couplings are a specific type of fitting manufactured by Plidco used to join two sections of pipe. Once the coupling is in place and the clamping and thrust screws are tightened, flow is initiated in the pipeline to keep the seal materials from sustaining heat damage during welding. A fillet weld is completed around the pipeline at both ends of the coupling to effect permanent installation.

The Notice also alleged that Respondent failed to ensure the proper torque was applied to the clamp and thrust screws during the installation of the couplings and failed to double-check the torque applied to the clamp screws as required by the procedure.

In its Response and Brief, Enbridge did not contest the allegation of violation "in so far as the procedures it followed on November 28, 2007 were not consistent with an unanchored pipe setting."[3] Enbridge offered no further statements or arguments in response to this allegation of violation.

Respondent's removal of clamp screws and its failure to ensure that proper torque was applied constituted failures to follow the company's written procedures for installation of the couplings. Accordingly, after considering the evidence, I find that Respondent violated 49 C.F.R. § 195.402(a) by failing to follow its written procedures for the installation of the couplings.

Item 2: The Notice alleged that Respondent violated 49 C.F.R. § 195.402(a), quoted above, by failing to follow its written procedures for anchoring the pipeline during the repair project. Specifically, the Notice alleged that on the day in question, Enbridge did not anchor the pipeline as required by its procedures prior to increasing pressure in the pipeline above designated limits for unanchored pipe. The Notice further alleged that as Enbridge attempted to increase pressure in the pipe to levels only permitted for anchored pipe, the pipe moved, causing a coupling to fail.

In its Response, Enbridge indicated that it did not intend to contest the merits of the allegation. In its Brief, however, the company contested the allegation that the company violated § 195.402(a) as alleged. Respondent contended that it followed its written procedures, but that the procedures did not necessarily provide guidance about how to conduct an assessment to determine if pipe is anchored. Respondent explained that its pipeline was "uniquely exposed and positioned" at the repair site. It stated that the exposed pipe had a slight downward slope of approximately 1.5 degrees and an offset of approximately 7.5 feet horizontally and 2.5 feet vertically, which "affected the anchoring of the pipeline, making it partially, not fully anchored."[4] The company stated that at the time of the accident, Enbridge employees believed the pipe was fully anchored because the pipe had not shifted when certain restraints were removed. Respondent explained that its written procedures did not describe how or when an anchoring assessment should be made based on the degree to which its pipeline was exposed or had deviations in alignment.

After a review of the evidence, I note that Enbridge Procedure 06-03-13 required, among other things as part of the installation of the couplings, that the pipeline be refilled to a working pressure. The pressure limit was based on whether or not the pipe was "anchored."[5] The procedures noted that a "[p]ipe is anchored if it is protected from movement in all directions so it will be unaffected by, for example, abrupt pressure changes, temperature changes, or oil movement (e.g., buried pipe)."[6] The manufacturer's procedures for installing the couplings provided, among other things, that the couplings "must not be tested above the *Pipe Not*

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[3] Brief at 5.

[4] Brief at 6.

[5] Violation Report, Exhibit D2, Enbridge Procedure 06-03-13, at 3.

[6] Violation Report, Exhibit D2, Enbridge Procedure 06-03-13, at 3.

Anchored rating" if the pipe is in an unanchored condition.[7] The procedures also stated that installers must "[r]ead and carefully understand the definition of *Anchored Pipe*, *Pipe Not Anchored* and *After Welding* as listed in the *Safety Check List* before pressurizing the line."[8]

Enbridge personnel considered the pipe to be anchored and pressurized the line above the specified limit for unanchored pipe, resulting in the failure of at least one coupling. Enbridge's accident investigation report noted that "separation of the newly installed Weld+Ends Coupling occurred as a result of inadequate restraint that allowed the Weld+Ends Coupling to slip sufficiently resulting in the release of crude oil when crude oil flow in Line 3 was being restarted."[9]

It is evident from the circumstances of the accident that the pipe was not protected from movement in all directions. Respondent acknowledged in its Brief that the pipeline was "partially, not fully, anchored."[10] At the hearing, Enbridge acknowledged that its procedures did not contemplate "partial anchoring," and that under the procedures, the pipeline was either anchored or not anchored. I find that since Respondent's pipeline was not "protected from movement in all directions," as specified in its procedures, the pipeline was not anchored. The facts indicate, therefore, that Respondent did not comply with its procedures for anchoring the pipeline prior to increasing pressure in the pipeline above the limit for unanchored pipe.

I decline to follow Respondent's argument that since the procedures did not provide guidance about determining acceptable anchoring, the company complied with § 195.402(a) by simply following the deficient procedures. Respondent's written procedures were clear enough to specify that an anchored pipe is one that cannot be moved by expected changes in pressure or the movement of oil. The responsibility rested with Respondent to comply with its procedures by determining through necessary means whether its pipeline met the criteria for anchored pipe before proceeding on the assumption that its pipeline was anchored.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 195.402(a) by failing to follow its written procedures for anchoring the pipeline prior to increasing pressure above the limit specified for unanchored pipe.

Item 3: The Notice alleged that Respondent violated 49 C.F.R. § 195.402(a) and (c)(13), which state:

> **§ 195.402 Procedural manual for operations, maintenance, and emergencies.**
>
> (a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies . . . .

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[7] Violation Report, Exhibit D1, Plidco Weld+Ends Installation Instructions, at 5 (emphasis in original).

[8] Violation Report, Exhibit D1, Plidco Weld+Ends Installation Instructions, at 5 (emphasis in original).

[9] Violation Report, Exhibit E, Enbridge Investigation Report, at 9

[10] Brief at 6.

> (c) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations . . .
>
> (13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

The Notice alleged that Respondent violated § 195.402(a) and (c)(13) by failing to periodically review the work performed by its personnel to determine the effectiveness of the company's procedures for installing Weld+Ends couplings. Specifically, the Notice alleged that over a number of years Enbridge employees routinely removed clamp screws on Weld+Ends couplings prior to installation, a practice not permitted by the company's written procedures and which contributed to the accident on November 28, 2007. In addition, the Notice alleged that torque values were not routinely checked as required by the procedures.

The record includes PHMSA inspectors' notes from interviews with Enbridge employees following the November 28, 2007, accident. At least seven employees stated during those interviews that, in their experience, Enbridge had routinely removed clamp screws when installing Weld+Ends couplings.[11] For example, "Employee 1" had been a supervisor with Enbridge since 1996, and an Enbridge employee since 1984. He stated that it had always been the practice since he started working with Enbridge to cut alternate bolts off Weld+Ends couplings before installing them. "Employee 2" had been a manager at Enbridge since 2001, a supervisor with the company for 11 years before that, and had been with the company for 25 years. He indicated that some company supervisors had adopted the practice of cutting off some of the clamp screws prior to installing Weld+Ends couplings, and that this practice had never been a safety concern before because the installations had held up. "Employee 3" had been a supervisor with Enbridge since 1997 and an Enbridge employee for 33 years. He estimated that he had been involved in 20 to 30 installations of Weld+Ends couplings, and stated that it was common practice to cut off approximately half of the clamping screws prior to their installation.

"Employee 4" had been a project coordinator with Enbridge since 2002, a welder for two years before that, and had been with the company since 1988. He had been involved in approximately 12 Weld+Ends coupling installations with the company, the most recent in 2000 or 2001. He noted that in his experience, some clamping bolts were cut off in advance of the installation if time permitted. "Employee 5" had been a supervisor for Enbridge for 3 years and employed with the company for 18 years. He recalled installing one such fitting in the 1990s after the clamp screws were cut off. "Employee 6" had been a supervisor for Enbridge for 15 years and employed with the company for 36 years. Prior to becoming a supervisor, he recalled cutting off some of the clamp screws to prepare Weld+Ends couplings for installation. "Employee 7" had been a supervisor for 2 years and a welder for 13 years prior to that, and has been employed with Enbridge for 24 years. He also recalled cutting off clamp screws prior to installing such fittings.

In its Response, Enbridge indicated that it did not intend to contest the merits of the allegation. In its Brief, however, the company argued, among other things, that it had been a long time since Employees 4 and 5 were involved in the installation of Weld+Ends couplings, and that their

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[11] The employees are identified by name in the record, but their names are not included in this Final Order.

statements should not be relied on as an accurate account of "how Enbridge in fact conducts these installations in every instance."[12] Respondent also argued that a post-accident review of its inventory indicated Weld+Ends couplings stored at various locations had intact clamp screws, and that this refutes any statement "that Enbridge always removed clamp screws from Weld+Ends couplings prior to installation."[13]

I agree that the employees' statements do not necessarily prove that Enbridge *always* removed clamp screws from Weld+Ends couplings prior to installation. Whether or not Enbridge removed clamp screws in every instance is not the issue, however. The record shows that at least seven Enbridge supervisors had personal experience at the company with the practice of removing clamp screws prior to installation over several years. Respondent did not contest the validity of the employees' statements, other than to note the time since Employees 4 and 5 were involved in the installation of the couplings. At a minimum, the evidence demonstrates employees at Enbridge had removed clamp screws prior to installing Weld+Ends couplings and that this occurred with enough regularity that some employees considered it "the practice."

Enbridge further contended that its training and operator qualification programs had satisfied the company's obligation to review employee work under § 195.402(c)(13). The company listed individuals that had been trained and qualified to install Weld+Ends couplings, providing details regarding its training and qualification program. Enbridge noted that its qualification program required observations of task performance.

Training and qualification reviews performed for the purpose of evaluating an individual's knowledge and ability to perform a task do not constitute compliance with § 195.402(c)(13). The regulation requires each operator to have and follow written procedures for periodically reviewing the work done by operator personnel to determine *the effectiveness of the operating and maintenance procedures* and for taking corrective action where deficiencies are found to ensure safety during operations and maintenance. I have reviewed the extent to which Respondent reviewed employee work during personnel training and operator qualifications, however, there is no evidence that the work reviews conducted for personnel training and qualification purposes were performed for the purpose of determining the effectiveness of the Weld+Ends installation procedures themselves. Respondent did not submit documentation that it had evaluated the procedures, nor is there any evidence in the record that Enbridge took corrective action to address apparent deficiencies in its procedures that had led personnel to believe they were permitted to remove clamp screws prior to installation. Therefore, reviewing work for purposes of training and qualification was not an adequate substitute for complying with § 195.402(c)(13).

In addition, Enbridge explained that the company had not experienced a prior incident related to the installation of at least 167 other Weld+Ends couplings. Respondent contended the absence of prior accidents demonstrates that the company had reviewed the work performed by personnel as required under § 195.402(c)(13). Enbridge also included evidence of several specific Weld+Ends couplings that it verified were installed properly.

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[12] Brief at 10. Enbridge also claimed that a number of other employees, who are not referenced above as "Employees 1 through 7" had no personal experience conducting Weld+Ends coupling installations.

[13] Brief at 10.

The absence of prior accidents and evidence that certain couplings were installed properly do not demonstrate that the company reviewed the work to determine the effectiveness of the procedures. The accident that occurred in this case was a result of multiple factors, not only the improper removal of some clamp screws. Therefore, it does not follow that had another coupling been improperly installed, there would have definitely been another accident. Furthermore, as Respondent noted in its Brief, clamp screws may not always bear an axial load if the pipe is completely anchored during installation.[14] The absence of prior accidents does not prove that Enbridge actually performed work performance reviews to determine the effectiveness of its procedures.

Enbridge also argued that the installation of Weld+Ends couplings with missing clamp screws and the failure to check torque values are not necessarily inconsistent with Enbridge's procedures if the pipe is fully anchored, because there would be no axial load transferred by the couplings. This argument is presumably made to imply that even if the company had periodically reviewed the installation of Weld+Ends couplings, its procedures were effective and did not require any corrective action.

I determined above, however, that removal of clamp screws and failure to check torque values were not in accordance with Respondent's written procedures, which required the company to "[d]ouble-check all clamp screws to ensure each has received the specified torque."[15] The manufacturer's procedures for installing the couplings also required the company to "[c]heck all the clamp screws to make certain each has been tightened to the minimum torque specified in the chart below."[16] Enbridge's removal of clamp screws prior to installing Weld+Ends couplings demonstrates the procedures had not been consistently implemented, and that the company had not determined the procedures were deficient based on a review of work performed.

Finally, Respondent contended that § 195.402(c)(13) requires only that operators review work "periodically," and therefore Enbridge was not actually required to conduct a review of the Weld+Ends couplings installation "on November 28, 2007, or at any specific time prior."[17]

There is no evidence that Respondent ever conducted periodic reviews of Weld+Ends coupling installations in order to determine the effectiveness of the applicable procedures. Section 195.402(c)(13) is a performance standard that requires operators to have and follow procedures for conducting reviews at a sufficient frequency to ensure the effectiveness of its procedures and to provide safety during operations and maintenance. Had Enbridge actually conducted the necessary reviews at an established interval for the purpose of determining the effectiveness of its procedures, I could evaluate whether or not that interval was adequate for § 195.402(c)(13).

Accordingly, after considering all of the evidence, I find that Respondent violated § 195.402(a) and (c)(13) by failing to periodically review the work performed by its personnel to determine

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[14] Brief at 10.

[15] Violation Report, Exhibit D2, Enbridge Procedure 06-03-13, at 3. Enbridge's procedures also required the company to "[s]nug all the clamp screws evenly . . . ." *Id.* at 2.

[16] Violation Report, Exhibit D1, Plidco Weld+Ends Installation Instructions, at 5.

[17] Brief at 11.

the effectiveness of the company's procedures for installing Weld+Ends couplings and to take corrective action to address deficiencies.

Item 4: The Notice alleged that Respondent violated 49 C.F.R. § 195.406(a)(2) and (b), which state:

> **§ 195.406 Maximum operating pressure.**
> (a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following . . .
> (2) The design pressure of any other component of the pipeline . . . .
> (b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

The Notice alleged that Respondent violated § 195.406(a)(2) and (b) by operating its pipeline at a pressure that exceeded the design pressure of the Weld+Ends couplings on November 28, 2007. Specifically, the Notice alleged that the manufacturer's installation instructions as well as Enbridge's written procedures had designated the maximum working pressure of the couplings on unanchored pipe to be approximately 74 psig (although Respondent's removal of clamp screws prior to installation effectively reduced this limit). On November 28, 2007, the working pressure of the pipeline was allowed to increased over 74 psig until at least one of the couplings failed at a pressure of approximately 282 psig. The operation of the pipeline at 282 psig also exceeded 110 percent of the maximum working pressure.

In its Response and Brief, Enbridge did not contest this allegation of violation. Accordingly, after considering the evidence, I find that Respondent violated 49 C.F.R. § 195.406(a)(2) and (b) by operating its pipeline at a pressure that exceeded the design pressure of the couplings on unanchored pipe and that exceeded 110 percent of the maximum working pressure.

Item 5: The Notice alleged that Respondent violated 49 C.F.R. § 195.422(a), which states:

> **§ 195.422 Pipeline repairs.**
> (a) Each operator shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property.
> (b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

The Notice alleged that Respondent violated § 195.422(a) by failing to repair its pipeline in a safe manner to prevent injury to persons and damage to property. As described more fully above, Enbridge attempted to complete a repair on its pipeline near Clearbrook, Minnesota, on November 28, 2007, by installing a new 11-foot section of pipe using Weld+Ends couplings. As the flow of crude oil through the pipeline started, one of the couplings slipped, allowing the discharge of crude oil, which subsequently ignited. The two primary causes of the accident were the failure of the Weld+Ends couplings, described above, and the presence of an ignition source at the excavation site. An open flame heater had been positioned at the edge of the excavation to provide heat to the crew during the repair. "The safety zone established during the restart of Line 3 was inadequate due to the presence of an open flame heater."[18] The resulting fire caused the deaths of two Enbridge employees and property damage to the pipeline and construction equipment.

In its Response and Brief, Enbridge did not contest this allegation of violation. Accordingly, after considering the evidence, I find that Respondent violated 49 C.F.R. § 195.422(a) by failing to repair its pipeline in a safe manner to prevent injury to persons and damage to property.

Item 6: The Notice alleged that Respondent violated 49 C.F.R. § 195.422(b), quoted above, by failing to use fittings for the repair project that were designed and constructed in accordance with 49 C.F.R. Part 195. Specifically, the Notice alleged that the two couplings used by Enbridge on November 28, 2007, were not designed and constructed in accordance with § 195.118(c), which requires that each "fitting must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system to which it is attached." The two couplings used by Enbridge had been improperly modified prior to installation by removing approximately half of the clamp screws. The Notice alleged that such modifications significantly reduced the pull-out resistance of the couplings, making them unsuitable for their intended service and not as strong as the pipe and other fittings in the system.

In its Response and Brief, Enbridge did not contest the allegation of violation "in so far as the procedures it followed on November 28, 2007 were not consistent with an unanchored pipe setting."[19]

The evidence demonstrates that the two couplings used by Enbridge had been modified prior to installation by removing approximately half of the clamp screws. This modification "had a direct bearing on the available restraint, support, or anchoring" of the pipe and coupling.[20] The failure of one of the couplings "occurred as a result of inadequate restraint that allowed the Weld+Ends Coupling to slip sufficiently resulting in the release of crude oil."[21] Accordingly, after considering the evidence, I find that Respondent violated 49 C.F.R. § 195.422(b) by failing to use fittings that were suitable for the intended service and at least as strong as the pipe and other fittings in the pipeline system.

Item 7: The Notice alleged that Respondent violated 49 C.F.R. § 195.505(e), which states:

> **§ 195.505 Qualification program.**
> Each operator shall have and follow a written qualification program. The program shall include provisions to . . .
> (e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task . . . .

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[18] Violation Report, Exhibit E, Enbridge Investigation Report, at 11.

[19] Brief at 12.

[20] Violation Report, Exhibit E, Enbridge Investigation Report, at 10.

[21] Violation Report, Exhibit E, Enbridge Investigation Report, at 9.

The Notice alleged that Respondent violated § 195.505(e) by failing to follow its written qualification procedures for evaluating covered task changes to determine if employees were no longer qualified to perform a covered task.[22] Specifically, the Notice alleged that Enbridge's written operator qualification (OQ) plan required the company to assess changes affecting covered tasks to determine if employees must be re-qualified, but that Respondent failed to assess the changes made to its OQ plan in October 2007 to determine whether elimination of the covered task "Pipeline Repair (Task 40)" and the addition of separate covered tasks for the various types of pipeline repairs required employees to be re-qualified.[23]

The Notice further alleged that on November 28, 2007, the employees participating in the repair activity had been qualified under the former "Pipeline Repair" covered task based on an evaluation of their performance during the installation of repair sleeves, but that they had not been qualified on their knowledge and performance regarding Weld+Ends couplings. The individuals nevertheless were considered by Enbridge to be qualified for all pipeline repairs, including Weld+Ends coupling installation.

In its Response, Enbridge indicated that it did not intend to contest the merits of the allegation. In its Brief, however, the company contended that it had complied with § 195.505(e) by evaluating whether its employees needed to be re-qualified following the changes to the OQ plan in October 2007. Respondent explained that it had concluded as a result of the assessment "that Enbridge did not immediately have to re-qualify any of its employees for any of the separate covered tasks, [but that] any such re-qualification would take place when it was convenient, not necessarily immediate, or prior to any Enbridge employee actually performing any of the covered tasks, including the installation of Weld+Ends couplings task."[24] At the hearing, Respondent further indicated that some of the employees on-site November 28, 2007, had been qualified "on all of the repair tasks," and that some of them also had "been involved in the installation of Weld+Ends couplings in the past."[25]

After a review of the evidence, I note that Enbridge's OQ plan specified that "[c]hanges, which affect covered tasks, will be assessed by the plan administrator to determine if re-qualification is necessary. If re-qualification is required, all affected individuals will be notified and re-qualified by their supervisors/evaluators."[26] While Respondent indicated in its Brief and at the hearing that the company performed such an assessment to determine if individuals needed to be re-qualified following the changes to its OQ plan, I find an absence of evidence in the record

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[22] An employee is "qualified" to perform a covered task if the individual has been evaluated by the operator and determined to be able to perform the assigned covered task and recognize and react to abnormal operating conditions. § 195.503. A "covered task" is a pipeline operations or maintenance activity, identified by the operator, that is performed as a requirement of Part 195 and that affects the operation or integrity of the pipeline. § 195.501.

[23] Violation Report, Exhibit F4, email and task list from Enbridge Qualifications Coordinator dated Nov. 8, 2007.

[24] Brief at 13-14. *See also* Transcript at 102–108. Enbridge's Vice President of Operations explained at the hearing that the company had recognized there might not be an opportunity for all of its employees to observe installation of Weld+Ends couplings because the company did not use them very often. The company was considering other opportunities for employees including training from the manufacturer.

[25] Transcript at 107.

[26] Violation Report, Exhibit F2, Enbridge OQ Plan (Mar. 1, 2007), Section 9.3.1, "Covered Task Changes," at 21.

supporting that assertion.[27] Notably absent from the record is any written assessment or other documentation demonstrating that Respondent evaluated whether employees' previous qualifications under the former "Pipeline Repair" covered task included the performance evaluations necessary to qualify them for the specific covered task of installing Weld+Ends couplings.

For example, the evidence in the record demonstrates that under the former "Pipeline Repair" covered task, no specific technical training had been required for employees to be qualified to install Weld+Ends couplings.[28] Personnel qualification records for individuals on-site at the time of the accident indicated that the employees were considered qualified for all pipeline repairs based solely on an evaluation of their installation of tight fitting repair sleeves. None of the employees had been qualified through evaluations specific to the installation of Weld+Ends couplings, such as verbal review of task procedures or observation of task performance, either real or simulated.[29]

Furthermore, although Respondent indicated that the company had concluded that re-qualifications of the individuals would take place "prior to any Enbridge employee actually performing any of the covered tasks, including the installation of Weld+Ends couplings task," the company had not re-qualified the employees that were on-site on November 28, 2007.[30]

As stated in the Notice, the installation of Weld+Ends couplings requires a certain set of knowledge, skills, and abilities, particularly with regard to properly installing clamp screws, ensuring anchoring and support, and selecting working pressures. After amending its OQ plan, Enbridge was required to verify that individuals performing the installation of Weld+Ends couplings could perform the covered task safely and could recognize and react to abnormal operating conditions. There is no record of Enbridge evaluating whether the October 2007 change to its OQ plan required individuals to be re-qualified in order to install Weld+Ends couplings.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 195.505(e) by failing to follow its written qualification procedures for evaluating covered task changes to determine if the employees that would perform the pipeline repair project at MP 912 had to be re-qualified in order to install the Weld+Ends couplings.

Item 8: The Notice alleged that Respondent violated 49 C.F.R. § 195.505(h), which states:

> **§ 195.505 Qualification program.**
> Each operator shall have and follow a written qualification program. The program shall include provisions to . . . .

[27] Enbridge is required to maintain records that demonstrate compliance with § 195.505(e) pursuant to the recordkeeping requirement in § 195.507.

[28] Violation Report, Exhibit E, Enbridge Investigation Report, at 12.

[29] Violation Report, Exhibit F5, Enbridge Operator Qualification Evaluation Records.

[30] Brief at 13-14. Enbridge indicated at the hearing that at least one contractor was "qualified" for Weld+Ends, but Enbridge acknowledged the individual had not been qualified under Enbridge's OQ plan, and further acknowledged that Enbridge did not permit contractors to install Weld+Ends couplings. Transcript at 109-111. For this reason, I do not give the contractors' qualifications further consideration.

> (h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities . . . .

The Notice alleged that Respondent violated § 195.505(h) by failing to provide training after December 16, 2004, to ensure that individuals installing Weld+Ends couplings had the knowledge and skills necessary to perform the task in a safe manner. Training and OQ records for the Enbridge personnel who were on-site during the installation project allegedly demonstrated that only four of the employees had been trained on Weld+Ends couplings, and that their training had not been conducted after December 16, 2004. The Notice also alleged that employees on-site for the installation project were not sufficiently familiar with clamp bolt and thrust bolt torque requirements, piping restraint and support requirements, and operating pressure requirements pertaining to Weld+Ends couplings, demonstrating they did not have the knowledge and skills necessary to perform the task in a manner that ensures safety.

In its Response, Enbridge indicated that it did not intend to contest the merits of the allegation. In its Brief, however, the company contended that it had complied with § 195.505(h) by providing training for the individuals to be qualified under the former "Pipeline Repair" covered task. Enbridge asserted that nothing in the regulation required the company to specifically train its employees for Weld+Ends couplings. Respondent asserted further that § 195.505(h) required only that employees be trained for covered tasks listed in the OQ Plan, which at that time had a single covered task for all pipeline repairs. Enbridge explained that "[u]nder this OQ regime, Enbridge employees could be performance evaluated, for example, only on installation of tight fitting repair sleeves, and as such, be considered qualified for Pipeline Repair (Task 40), though the employee may not have been specifically performance evaluated on any of the other activities under Pipeline Repair (Task 40), including installation of Weld+Ends couplings."[31]

Enbridge's position is predicated on the assumption that § 195.505(h) only required training for a task if that activity had been identified as a separate covered task in the company's OQ plan. Under this rationale, if the operator's OQ plan did not identify Weld+Ends as a *separate* covered task, the company did not have to provide specific training for personnel to perform the activity. This is far too narrow a view of the regulatory requirement.

The installation of Weld+Ends couplings is a maintenance activity that is performed on a pipeline facility pursuant to 49 C.F.R. Part 195 and that affects the integrity of the pipeline. The activity involves specific knowledge, skills, and abilities to ensure the task is performed in a manner that ensures safety. Thus the activity is a "covered task," as that term is defined in § 195.501, regardless of whether Enbridge had identified the activity separately in its OQ plan or whether it had lumped it together with other types of pipeline repairs into a combined OQ item. Since the installation of Weld+Ends couplings is a covered task, Enbridge was required to provide training for each individual performing the activity to ensure they had the necessary knowledge and skills to perform the task in a safe manner.

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[31] Brief at 13.

The record shows that Enbridge employees performing the installation of Weld+Ends couplings on November 28, 2007, had not been provided the required training for performance of this covered task. While several individuals had received some training in Weld+Ends, other individuals had only received training sufficient to support being qualified to perform other activities under "Pipeline Repair (Task 40)," and had not received specific training for Weld+Ends couplings, as mandated by the regulation.[32]

Enbridge also argued that PHMSA previously reviewed the company's OQ plan between 2004 and 2005 and did not take issue with the fact that pipeline repairs were combined together into a single covered task. PHMSA is not precluded from bringing a violation for conduct that was not previously identified during an inspection. Moreover, it may not have been clear that Enbridge believed § 195.505(h) did not require the company to provide separate training on Weld+Ends couplings installation. Section 195.505(h) requires the company to provide training for each covered task, regardless of whether the activity is identified separately in the OQ plan or combined with other activities.

After considering all of the evidence, I find that Respondent violated 49 C.F.R. § 195.505(h) by failing to have and follow provisions in its written qualification program to provide training, as appropriate, to ensure that individuals performing the installation of Weld+Ends couplings had the necessary knowledge and skills to perform the task in a manner that ensures the safe operation of the pipeline facility.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to an administrative civil penalty not to exceed $100,000 per violation for each day of the violation up to a maximum of $1,000,000 for any related series of violations. The Notice proposed a total civil penalty of $2,405,000 for the eight violations identified above.

In determining the amount of a civil penalty under 49 U.S.C. § 60122 and 49 C.F.R. § 190.225, I must consider the following criteria: the nature, circumstances, and gravity of the violation, including adverse impact on the environment; the degree of Respondent's culpability; the history of Respondent's prior offenses; the Respondent's ability to pay the penalty and any effect that the penalty may have on its ability to continue doing business; and the good faith of Respondent in attempting to comply with the pipeline safety regulations. In addition, I may consider the economic benefit gained from the violation without any reduction because of subsequent damages, and such other matters as justice may require.

[32] The Notice seemed to imply that any training provided by Enbridge prior to December 16, 2004, could not have satisfied the requirement in § 195.505(h) by virtue of its timing. I decline to interpret the regulation in that manner, but note the facts demonstrate that certain individuals on-site for the installation project had not received any specific training for Weld+Ends couplings, regardless of timing, and that even those who apparently had received training did not have the knowledge and skills necessary to perform the task in a manner that ensured safety.

In its Brief, Enbridge argued that some of the penalty assessment criteria had not been given appropriate consideration and requested that the civil penalty be reduced. First, Respondent contended that PHMSA had not considered the good faith of Enbridge in attempting to achieve compliance with the pipeline safety regulations prior to the accident. Respondent asserted that it had company departments whose responsibility was to ensure regulatory compliance and to manage the integrity of its pipeline. The company also explained that it had routinely arranged "pre-audits" with PHMSA in advance of its regular PHMSA inspections.[33]

Second, Respondent contended that the agency had not properly considered certain "other matters as justice may require." Enbridge suggested such matters should include its efforts immediately following the accident to investigate and determine causation, implement interim procedures to address issues from the accident investigation, prevent reoccurrence, and fully cooperate with PHMSA. I address Respondent's good faith and "other matters" arguments below for each item.

Third, Respondent contended that the civil penalty does not appear to have taken into account evidence and testimony regarding its efforts to fulfill the terms of the proposed compliance order. I address the extent to which Respondent may have fulfilled such terms below in the Compliance Order section, but with respect to the civil penalty, I find the evidence of corrective measures taken after issuance of the Notice does not serve to reduce the proposed penalty.

Finally, Respondent contended that the civil penalty amount set forth in the Notice exceeds the maximum penalty permitted by statute. In particular, Enbridge argued that Items 1, 2, 3, 4, 6, 7, and 8 were all one related series of violations, because the violations were all based on the allegation that the company failed to install couplings properly on the date of the accident. Respondent explained that "the entire sequence of the overlapping and cumulative events that underlie [the Items] constitute a related series of violations."[34]

Administrative civil penalty assessments by PHMSA are governed by the following provision of 49 U.S.C. § 60122(a)(1), as well as 49 C.F.R. § 190.223(a):

> A person that the Secretary of Transportation decides, after written notice and an opportunity for a hearing, has violated section 60114(b), 60114(d), or 60118(a) of this title or a regulation prescribed or order issued under this chapter is liable to the United States Government for a civil penalty of not more than $100,000 for each violation. A separate violation occurs for each day the violation continues. The maximum civil penalty under this paragraph for a related series of violations is $1,000,000.

As set forth previously by this agency, "a related series of violations" means a series of daily violations in light of the sentence that comes before it.[35] In *Colorado Interstate Gas*, PHMSA explained that multiple violations listed in a single Notice of Probable Violation do not constitute

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[33] Brief at 16.

[34] Brief at 16.

[35] *In the Matter of Colorado Interstate Gas Co.*, Final Order, CPF 5-2008-1005, 2009 WL 5538649, at 11 (Nov. 23, 2009) (cases are also available online at "http://www.phmsa.dot.gov/pipeline/enforcement").

a "related series" just because they all involve the same subject matter or were all contributing factors in the same pipeline accident. PHMSA stated further that "[n]othing in this statute prohibits PHMSA from assessing total civil penalties of over $1,000,000 in a case as long as the violations are separate."[36]

PHMSA noted, however, that certain violations in a Notice of Probable Violation may be so related that they constitute a single offense for which the agency should not assess combined penalties exceeding the applicable cap. In determining whether two or more violations are so closely related, the decision in *Colorado Interstate Gas* evaluated "whether each [Notice Item] can stand alone and has its own evidentiary basis, or whether any two or more are so closely related (i.e., same evidentiary basis) that they are not separate and should be considered one violation for purposes of applying the [penalty cap]."[37] Using this approach, I evaluate each of the following Notice Items and apply the above-referenced penalty assessment criteria.

Item 1: The Notice proposed a civil penalty of $100,000 for Respondent's violation of 49 C.F.R. § 195.402(a). As discussed above, I found that Enbridge violated the regulation by failing to follow its written procedures for the installation of Weld+Ends couplings. Those procedures required Enbridge to tighten all clamp screws evenly around the pipe and to ensure certain torque specifications listed in the procedure. Enbridge personnel had removed approximately one half of the clamp screws on the couplings prior to installation and also failed to ensure proper torque had been applied to the clamp and thrust screws. The failure to follow such installation procedures contributed to the slipping of at least one of the couplings, allowing the discharge of crude oil, which ignited causing the deaths of two employees and property damage. This violation was a causal factor in the accident. For these reasons, I find the nature, circumstances, and significant gravity of the violation justify the proposed civil penalty.

I have considered the above-referenced assertions by Enbridge regarding good faith, but find that its statements of general processes in place to manage compliance and pipeline integrity do not demonstrate a specific attempt to comply with an otherwise clear requirement to follow its procedures for installing Weld+Ends couplings. I have also considered the "other matters" suggested by Enbridge, but find that the efforts by the company following the accident were in many respects already required under the pipeline safety regulations[38] and otherwise would be expected of any prudent operator following an accident. Therefore these actions do not warrant reducing the penalty. This violation involves a failure to install fittings in accordance with certain procedures, and is not so related to any other violation that they constitute a single offense for purposes of the penalty cap.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $100,000 for the violation of 49 C.F.R. § 195.402(a).

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[36] *Colorado Interstate Gas Co.* at 11.

[37] *Colorado Interstate Gas Co.* at 12.

[38] *See, e.g.*, §§ 195.60 (requiring operators to afford all reasonable assistance in the investigation of an accident by PHMSA) and 195.402(c)(5)-(6) (requiring operators to analyze pipeline accidents to determine their causes and to minimize the possibility of recurrence of such accidents).

Item 2: The Notice proposed a civil penalty of $100,000 for Respondent's violation of 49 C.F.R. § 195.402(a). As discussed above, I found that Enbridge violated the regulation by failing to follow its written procedures for anchoring the pipeline prior to increasing pressure beyond a certain limit. Enbridge had not protected the pipe from movement in all directions, and the failure to anchor the pipeline contributed to the slipping of at least one of the couplings, allowing the discharge of crude oil, which ignited causing the deaths of two employees and property damage. This violation was a causal factor in the accident. For these reasons, I find the nature, circumstances, and significant gravity of the violation justify the proposed civil penalty.

I have considered the above-referenced assertions by Enbridge regarding good faith, but find that its statements of general processes do not demonstrate a specific attempt to comply with an otherwise clear requirement to follow its procedures for ensuring proper anchoring of the pipe. I have also considered the other matters, but as stated above, find that the company's efforts were in many respects already required and otherwise do not justify reducing the penalty. This violation involves a failure to anchor the pipe in accordance with certain procedures, and is not so related to any other violation that they constitute a single offense for purposes of the penalty cap.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $100,000 for the violation of 49 C.F.R. § 195.402(a).

Item 3: The Notice proposed a civil penalty of $1,000,000 for Respondent's violation of 49 C.F.R. § 195.402(a) and (c)(13). As discussed above, I found that Enbridge violated the regulation by failing to periodically review the work performed by its personnel to determine the effectiveness of the company's procedures for installing Weld+Ends couplings. Over a number of years, Enbridge personnel often removed clamp screws on Weld+Ends couplings in advance of installation. Respondent did not perform periodic reviews of work to determine that this practice was occurring and failed to amend its procedures as necessary to prevent the practice from reoccurring. It was not until after the accident on November 28, 2007, during which at least one coupling failed due in part to clamp screws having been removed, that Enbridge changed the procedure. The failure to review the work performed by its personnel and to take action to prevent the improper practice of removing clamp screws contributed to the accident. For these reasons, I find the nature, circumstances, and significant gravity of the violation justify the proposed civil penalty.

I have considered the assertions by Enbridge regarding good faith, but find that its statements do not demonstrate a specific attempt to review the work performed by its personnel to determine the effectiveness of the company's procedures for installing Weld+Ends couplings. I have also considered the other matters suggested by Enbridge, but as stated above, such efforts do not justify reducing the penalty. This violation involves a failure to review work over a number of years to determine the effectiveness of procedures and to take corrective action to ensure safe maintenance practices, and is not so related to any other violation that they constitute a single offense for purposes of the penalty cap. This was a continuing violation for which the penalty is capped by 49 U.S.C. § 60122(a)(1).

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $1,000,000 for the violation of 49 C.F.R. § 195.402(a) and (c)(13).

Item 4: The Notice proposed a civil penalty of $36,000 for Respondent's violation of 49 C.F.R. § 195.406(a)(2) and (b). As discussed above, I found that Enbridge violated the regulation by operating its pipeline at a pressure that exceeded the design of the couplings. The nature and circumstances of this violation demonstrate that it was a consequence of Enbridge's actions in Items 1 and 2, rather than a unique causal factor in the accident. For these reasons, I find the nature, circumstances, and gravity of the violation justify the proposed civil penalty.

I have considered the assertions by Enbridge regarding good faith, but find that the general processes do not demonstrate a specific attempt to maintain operating pressure within the designated limit for unanchored pipe. I have also considered the other matters suggested by Enbridge, but as noted above, the company's efforts after the accident do not warrant reducing the penalty. This violation involves a failure to keep operating pressure below designated limits, and is not so related to any other violation that they constitute a single offense for purposes of the penalty cap.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $36,000 for the violation of 49 C.F.R. § 195.406(a)(2) and (b).

Item 5: The Notice proposed a civil penalty of $100,000 for Respondent's violation of 49 C.F.R. § 195.422(a). As discussed above, I found that Enbridge violated the regulation by failing to repair its pipeline in a safe manner to prevent injury to persons and damage to property. During the pipeline replacement project, Respondent had placed an open flame heater in proximity to the excavation site, in addition to improperly installing the couplings and increasing pipeline pressure beyond the maximum working pressure for the couplings. The open flame ignited the discharged product causing the deaths of two employees and property damage. This violation was a causal factor in the accident. For these reasons, I find the nature, circumstances, and significant gravity of the violation justify the proposed civil penalty.

I have considered the assertions by Enbridge regarding good faith, but find that the general processes do not demonstrate a specific attempt to perform the pipeline repair project in a manner that prevented injury to persons and damage to property. I have considered the other matters suggested by Enbridge, but as noted above, the company's efforts after the accident do not warrant reducing the penalty. Respondent did not contend that this item was related to the others for purposes of the penalty cap.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $100,000 for the violation of 49 C.F.R. § 195.422(a).

Item 6: The Notice proposed a civil penalty of $39,000 for Respondent's violation of 49 C.F.R. § 195.422(b). As discussed above, I found that Enbridge violated the regulation by failing to use fittings for the pipe replacement that were suitable for their intended service and at least as strong as the pipe to which it was attached. The couplings used by Enbridge had been improperly modified by removing clamp screws, which significantly reduced their pull-out resistance. The nature and circumstances of this violation demonstrate that it was a consequence of Enbridge's actions in Item 1, rather than a unique causal factor in the accident. For these reasons, I find the nature, circumstances, and gravity of the violation justify the proposed civil penalty.

I have considered the assertions by Enbridge regarding good faith, but find they do not demonstrate a specific attempt to use unmodified couplings that were suitable for the intended service and had the necessary strength. I have considered the other matters suggested by Enbridge, but as noted above, find that the company's efforts after the accident do not warrant reducing the penalty. This violation involves a failure to use couplings with the necessary strength and suitability for the pipeline, and is distinguished from Item 1, which involves certain written procedures and torquing requirements that are not at issue in this violation. Therefore this item is not so related to any other violation that they constitute a single offense for purposes of the penalty cap.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $39,000 for the violation of 49 C.F.R. § 195.422(b).

Item 7: The Notice proposed a civil penalty of $30,000 for Respondent's violation of 49 C.F.R. § 195.505(e). As discussed above, I found that Enbridge violated the regulation by failing to assess whether employees needed to be re-qualified to install Weld+Ends couplings following changes to its OQ plan. Respondent had eliminated a single covered task that included all types of pipeline repairs and replaced it with separate covered tasks for the different repair activities. Respondent did not assess whether employees who had not previously been evaluated on the installation of Weld+Ends couplings, needed to be re-qualified before performing the covered task, and individuals installing Weld+Ends couplings on November 28, 2007, had not been evaluated on that task. The circumstances of this violation demonstrate that Respondent had just changed its OQ plan recently, and therefore I do not consider this violation to be a causal factor in the accident. For these reasons, I find the nature, circumstances, and gravity of the violation justify the proposed civil penalty.

I have considered the above-referenced assertions by Enbridge regarding good faith, but find they do not demonstrate a specific attempt to assess whether personnel needed to be re-qualified. I have also considered the other matters suggested by Enbridge, but as noted above, find that the company's efforts after the accident do not warrant reducing the penalty. This violation involves a failure to assess personnel qualifications after a change to the OQ plan, and is not so related to any other violation that they constitute a single offense for purposes of the penalty cap.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $30,000 for the violation of 49 C.F.R. § 195.505(e).

Item 8: The Notice proposed a civil penalty of $1,000,000 for Respondent's violation of 49 C.F.R. § 195.505(h). As discussed above, I found that Enbridge violated the regulation by failing to have and follow a written program to provide training to ensure that individuals performing the installation of Weld+Ends couplings had the necessary knowledge and skills to perform the task in a safe manner. Employees on-site for the pipe repair and replacement project on November 28, 2007, were not sufficiently familiar with clamp bolt and thrust bolt torque requirements, piping restraint and support requirements, and operating pressure requirements pertaining to Weld+Ends couplings, demonstrating they did not have the knowledge and skills necessary to perform the task in a manner that ensures safety. The failure to provide training for the installation of such couplings contributed to the fatal accident that occurred when at least one of the couplings failed during the installation. For these reasons, I find the nature, circumstances, and significant gravity of the violation justify the proposed civil penalty.

I have considered the above-referenced assertions by Enbridge regarding good faith, but find they do not demonstrate an attempt to provide specific training for personnel on installing Weld+Ends couplings. I have also considered the other matters suggested by Enbridge, but as noted above, find that the company's efforts after the accident do not warrant reducing the penalty. This violation involves a failure to provide personnel training, and is not so related to any other violation that they constitute a single offense for purposes of the penalty cap. This was a continuing violation for which the penalty is capped by 49 U.S.C. § 60122(a)(1).

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $1,000,000 for the violation of 49 C.F.R. § 195.505(h).

Respondent is culpable for all of the above violations, meaning that the company, as the operator of the pipeline, bears the blame for the violations that occurred on its pipeline system. I have also considered the company's history of prior offenses, including three Notices of Probable Violation, one of which involved a pipeline accident and spill of approximately 9,000 gallons of crude oil near Stanley, North Dakota (CPF No. 3-2007-5022).[39] I find the history of prior offenses does not warrant reducing the proposed civil penalty. In addition, since Respondent did not provide any evidence suggesting the company is unable to pay the proposed civil penalty, I find Respondent is able to pay the penalty without adversely affecting its ability to continue in business.

In summary, having reviewed the record and considered the assessment criteria for each of the Items above, I assess Respondent a total civil penalty of **$2,405,000**.

Payment of the civil penalty must be made within 20 days of receipt of this Final Order. Federal regulations (49 C.F.R. § 89.21(b)(3)) require this payment be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-341), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 269039, Oklahoma City, OK 73125; The Financial Division's telephone number is (405) 954-8893.

Failure to pay the $2,405,000 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9, and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a United States District Court.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to Items 1, 2, 3, 4, 7 and 8 in the Notice for the violations described above.

[39] *In the Matter of Enbridge Pipelines LLC–North Dakota*, Final Order, CPF 3-2007-5022, 2009 WL 2336996 (June 2, 2009). The other two cases are CPFs 3-2004-1007 and 4-2007-2001.

By letter dated December 1, 2009, Enbridge submitted information regarding the actions taken by the company that it believed complied with all of the provisions of the proposed compliance order. The Director has reviewed the information submitted by Enbridge and based on that review I find that although the information indicates Enbridge has initiated action towards compliance with the terms of the compliance order, the submission lacked documentation confirming that the items have been completed. For example, there is an absence of evidence demonstrating formal adoption and implementation of new and revised procedures, and an absence of documentation demonstrating the completion of necessary training and qualifications for appropriate personnel. For these reasons, I find the compliance order has not been satisfied and that Respondent must complete the measures specified below and submit documentation demonstrating completion.

Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids by pipeline or who owns or operates a hazardous liquid pipeline facility is required to comply with the applicable safety standards established under chapter 601. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations:

1. With respect to the violation of § 195.402(a) (**Item 1**), Respondent must review its procedures for using Plidco Weld+Ends couplings, and based on that review, revise or supplement the procedures as necessary to ensure the safe installation of the couplings. The procedures must ensure that unauthorized modifications of the component, such as cutting off clamp bolts on the couplings, do not occur. Communicate the latest procedures to the appropriate personnel and take measures to ensure that future installations of the couplings are performed accordingly.

2. With respect to the violation of § 195.402(a) (**Item 2**), Respondent must review its procedures for assessing and determining whether pipe is fully anchored to prevent movement in all directions while undergoing repairs at specified working pressures. Based on that review, revise or supplement the procedures as necessary to ensure proper anchoring of pipe when performing repairs and coupling installations on pressurized lines. Communicate the latest procedures to the appropriate personnel and take measures to ensure that future assessments of pipe anchoring are performed accordingly.

3. With respect to the violation of § 195.402(a) and (c)(13) (**Item 3**), Respondent must develop or revise existing procedures for reviewing the work performed by its personnel to determine the effectiveness of its repair procedures. The procedures must provide for reviewing repair procedures, observing work performance, and consulting with field personnel to identify any ineffective or inconsistently implemented repair procedures. The procedures must also provide for incorporating the information from such reviews into the periodic updates to Enbridge's procedural manual and training programs. Review current repair procedures to identify any ineffective or inconsistently implement procedures and take necessary action to address.

4. With respect to the violation of § 195.406(a)(2) and (b) (**Item 4**), Respondent must take measures to ensure that appropriate personnel have knowledge about the proper technique for pressurizing a pipeline that is undergoing a repair, including the manner in which safe pressure limits are calculated for various anchoring conditions. The technique must ensure that pressure does not exceed the design limit of the repair component at the time of the pressurization, and does not exceed 110 percent of that limit during surges or other variations from normal operations. Include the technique in Enbridge's manual of written procedures.

5. With respect to the violation of § 195.505(e) (**Item 7**), Respondent must qualify each individual who will be permitted to perform the covered task of installing Weld+Ends couplings on Enbridge's pipeline system. Individuals who were qualified to perform pipeline repairs under Enbridge's OQ plan prior to November 2007 must be re-qualified to install Weld+Ends couplings, unless Enbridge can demonstrate an individual has a current qualification that meets the requirements of § 195.505 specifically for Weld+Ends couplings.

6. With respect to the violation of § 195.505(h) (**Item 8**), Respondent must include in its written qualification program provisions to provide appropriate training to ensure that individuals performing the covered task of installing Weld+Ends couplings have the necessary knowledge and skills to perform the task in a manner that ensures the safe operation of the pipeline facility. Enbridge must provide such training to individuals who will be permitted to install Weld+Ends couplings on Enbridge's pipeline system.

7. Within 45 days of receipt of this Final Order, submit to the Director for written approval a schedule for completing the above-listed actions. Upon approval by the Director, Enbridge must complete the terms of this Compliance Order in accordance with that schedule and submit documentation of completion to the Director. Documentation of compliance includes, but may not be limited to: revised and supplemental procedures; documentation of work performance reviews for personnel; documentation of employee qualifications; training materials utilized; and documentation that training has been provided to personnel. Documentation shall be submitted to the Director, Central Region, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 901 Locust Street, Suite 462, Kansas City, MO 64106.

8. Enbridge shall perform the above required activities prior to using Weld+Ends couplings on its pipeline system, unless the Director provides otherwise in writing.

9. Maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to the Director. Costs shall be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.

The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent demonstrating good cause for an extension.

The required items are in addition to and do not waive any requirements that apply to Enbridge's pipeline system under 49 C.F.R. Part 195, under any other order issued to Enbridge under authority of 49 U.S.C. § 60101 et seq., or under any other provision of Federal or State law.

Failure to comply with this Order may result in administrative assessment of civil penalties not to exceed $100,000 for each violation for each day the violation continues or in referral to the Attorney General for appropriate relief in a district court of the United States.

Under 49 C.F.R. § 190.215, Respondent has a right to submit a Petition for Reconsideration of this Final Order. A petition must be sent to the Associate Administrator, Office of Pipeline Safety, PHMSA, 1200 New Jersey Avenue, SE, East Building, 2nd Floor, Washington, DC 20590, with a copy sent to the Office of Chief Counsel, PHMSA, at the same address. PHMSA will accept petitions received no later than 20 days after receipt of this Final Order by the Respondent, provided they contain a brief statement of the issue(s) and meet all other requirements of 49 C.F.R. § 190.215. The filing of a petition automatically stays the payment of any civil penalty assessed. All other terms of the order, including any required corrective action, shall remain in full force and effect unless the Associate Administrator, upon request, grants a stay. The terms and conditions of this Final Order are effective upon service in accordance with 49 C.F.R. § 190.5.

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

8/17/10
Date Issued

**IN THE CIRCUIT COURT FOR THE TWELFTH JUDICIAL CIRCUIT
WILL COUNTY, ILLINOIS**

ENBRIDGE ENERGY, LIMITED PARTNERSHIP, a Delaware limited partnership, Plaintiff, vs. OLDCASTLE APG, INC., d/b/a Northfield Block Company, a Delaware corporation, and VILLAGE OF ROMEOVILLE, an Illinois municipal corporation, Defendants.	Case No. 11 L 0727

DEFENDANT VILLAGE OF ROMEOVILLE'S
RENEWED MOTION FOR SUMMARY JUDGMENT

NOW COMES the Defendant, VILLAGE OF ROMEOVILLE, by and through their attorneys, MICHAEL D. BERSANI and YORDANA SAWYER of HERVAS, CONDON & BERSANI, P.C., and renews its motion for summary judgment pursuant to 735 ILCS 5/2-1005(b).

INTRODUCTION

In this suit, Plaintiff Enbridge Energy, Ltd. (hereinafter "Enbridge") alleges that the Defendant Village of Romeoville (hereinafter "Village") negligently failed to prevent the leak of a lateral water service Line ("Water Service Line") that supplied water to property owned by co-Defendant Old Castle APG, Inc. d/b/a Northfield Block Company (hereinafter "Northfield Block"). The Water Service Line was located approximately seven feet below the surface of Parkwood Avenue and crossed perpendicularly under a crude oil pipeline ("Oil Pipeline") owned and operated by Enbridge. In what Enbridge's experts have described as a "rare" and "unusual" occurrence, a water jet from the leaking Water Service Line, combined with sand, formed an erosive slurry ("Water Jet Slurry") that allegedly impinged or eroded a hole into the Oil Pipeline resulting in the release of crude oil into the environment. Enbridge is claiming that it incurred clean-up costs and other damages as a result of the leak incident.

Last year, the Village moved for summary judgment. Enbridge opposed the motion, in part, based on an affidavit from civil engineer, Paul Fleming. This Court denied summary judgment on December 23, 2014. Since then, Enbridge has formally disclosed Fleming as a controlled expert witness pursuant to Illinois Supreme Court Rule 213(f)(3), and the Village has taken Fleming's deposition. Suffice it to say, Fleming's deposition is a game changer. He admitted that the Village had no knowledge of the water leak and that Village employees "had no way of knowing" that a Water Jet Slurry was impinging a hole into Oil Pipeline. Fleming also admitted that any preventive maintenance activities by the Village of its water system, including the Water Service Line, were acts of discretion and involved policymaking. Finally, Fleming conceded that the Village had to make certain judgment calls in response to the leak incident.

Based in large part on Fleming's deposition testimony, the Village hereby renews its motion for summary judgment pursuant to Section 3-102 (lack of notice) and Section 2-201 (discretionary immunity) of the Illinois Tort Immunity Act. *See* 745 ILCS 10/2-201, 10/3-102 (West 2010). Additionally, in April 2015, the Appellate Court issued an opinion in *Nichols v. City of Chicago Heights*, 2015 IL App (1st) 122994, in which it held that a municipality's failure to conduct preventive maintenance on a municipal sewer system was subject to discretionary immunity under Section 2-201. *Nichols* dictates that the same result here. Accordingly, the Village is entitled to summary judgment as a matter of law.

STATEMENT OF UNDISPUTED MATERIAL FACTS

1. On September 9, 2010, Enbridge operated a 34" crude Oil Pipeline (hereinafter "Oil Pipeline") under the 700 block of Parkwood Avenue in Romeoville, Illinois (Ex. A, Village Answer, ¶ 4).

2. On September 9, 2010, Northfield Block operated a masonry manufacturing plant at 717 Parkwood Avenue (Ex. A, Village Answer ¶ 2).

3. Running perpendicular to and underneath the Oil Pipeline was a 6-inch lateral Water Service Line that supplied water to Northfield Block's property (hereinafter "Water Service Line") (Ex. A, Village's Ans., ¶ 5).

4. The Water Service Line ran laterally from the Northfield Block building and connected to an 8-inch public water main located west of the Oil Pipeline under Parkwood Avenue (Ex. A, Village's Ans., ¶ 6).

5. The Water Service Line was located seven feet below the surface of Parkwood Avenue and crossed five inches below the Oil Pipeline (Ex. B, Fleming Dep., pp. 70-71).

6. An accurate aerial depiction of the Oil Pipeline and Water Service Line and their respective orientation to each other and the surrounding area is attached hereto as a demonstrative exhibit (Ex. C, Aerial Depiction).

7. On September 9, 2010, at 9:36 a.m., a Village Public Works Department employee, Dale Wills, responded to a report of a water leak on Parkwood Avenue and observed water coming up through the pavement of Northfield Block's driveway off Parkwood Avenue and notified Northfield Block (Ex. D, Wills Dep., pp. 5-9, 12-14).

8. This was the Village's first notice of the water leak (Ex. B, Fleming Dep., p. 74; Ex. E, Bromberek Dep., pp. 126-127).

9. A water valve, otherwise known as a "stopcock," existed in the street and controlled the water flow to the Water Service Line (Ex. A, Village's Ans., ¶ 6).

10. Wills turned and closed the stopcock and observed the water recede from the pavement and concluded that the leak was on the Water Service Line (Ex. D, Wills Dep., pp. 12-17).

11. Wills subsequently turned and opened the stopcock, thereby restarting the water flow to the Water Service Line, and he then observed water reappearing through the pavement (Ex. D, Wills Dep., pp. 18-19, 37-38).

12. In deciding whether to turn the water back on, or leave it off, Wills considered whether the leak was endangering anyone or creating a traffic concern; whether Northfield Block would continue to have water for its operations; whether a leak detection company could locate the leak without the water flowing; and whether leaving the water off would cause back-contamination into the Village's water system (Ex. D, Wills Dep., pp. 18-21, 37-39; Ex. F, Drey Dep. I, pp. 89-90).

13. Enbridge's retained civil engineering expert, Peter Fleming, admitted that Wills acted reasonably in shutting down the water and notifying Northfield Block that the Water Service Line was leaking (Ex. B, Fleming Dep., pp. 77-79).

14. While Fleming disagreed with Wills' decision to turn the water back on, he admitted that Wills made a judgment call in this situation (Ex. B, Fleming Dep., pp. 88-90).

15. Fleming agreed that there was no rule or guideline that mandated Wills to keep the water service off while waiting for a leak detection service to arrive (Ex. B, Fleming Dep. pp. 175-178).

16. Northfield Block retained a leak detection company, Water Services, Inc., who responded to the leak site and needed the water flowing to determine the location of the leak (Ex. G, Northfield Block Ans. To Village Interrog. #5; Ex. H, Shelton Dep. I, 8/14/13, pp. 44).

17. Fleming agreed that, in determining the location of the leak, it was reasonable to have the water flowing (Ex. B, Fleming Dep., pp. 80-82, 87).

18. Upon arriving at the scene, Derek Shelton, an employee of Water Services, observed oil on the pavement (Ex. I, Shelton Dep., II, 12/9/13, p. 6).

19. This was the first notice of an oil leak (Ex. B, Fleming Dep., p. 74-75).

20. Fleming had no opinion as to whether Wills' actions in turning the water off and then back on caused the Oil Pipeline to leak (Ex. B, Fleming Dep., p. 101).

21. At 12:05 p.m., a call was placed to the Village's 911 call center about a gas odor on Parkwood Avenue (Ex. J, Panzer Dep., p. 13).

22. Romeoville Assistant Fire Chief Ed Panzer responded to the scene and called Enbridge's call center and reported the oil leak (Ex. J, Panzer Dep., pp. 17-23).

23. Enbridge's computerized leak detection system had not detected the oil leak prior to, or even immediately after, receiving the call from Panzer (Ex. K, Philipenko Dep., pp. 8-9).

24. At 1:45 p.m. on September 9th, the Public Works Department turned the stopcock to the off position, but the water continued to flow (Ex. D, Wills Dep., pp. 24-25; Ex. F, Drey Dep. I, pp. 40, 43-44, 79; Ex. E, Bromberek Dep., pp. 24-25).

25. This was the Village's first notice of any problem with the stopcock (Ex. E, Bromberek Dep., pp. 132-133).

26. Public Works Director Dan Bromberek was authorized and empowered by the Village to make the necessary decisions on behalf of the Village in response to the leak incident (Ex. E, Bromberek Dep., pp. 37, 136, 146-148; Ex. L, Gulden Dep., pp. 8-10, 12, 23-25).

27. In response to the incident, Bromberek made the decision *not* to shut off the valves to the Village's water main, which ran parallel to the Oil Pipeline in the street, because he was concerned that it would cause back-contamination of crude oil into the Village water distribution system, and he believed that he had the legal responsibility, as one of the certified operators of the water system, not to pump contaminated water through the system (Ex. E, Bromberek Dep., pp. 26-28, 109-110, 146-148, 151; Ex. L, Gulden Dep., pp. 24-25).

28. If crude oil contaminated the Village-wide system, the cost to remedy that contamination would have been significant, and the Village would have had to allocate resources in order to deal with that contamination (Ex. E, Bromberek Dep., p. 147).

29. Bromberek was also concerned that shutting off the water main valves on Parkwood Avenue would interrupt water service to the commercial and industrial users in the industrial park (Ex. E, Bromberek Dep., pp. 27-28, 147-148).

30. In making the decision not to shut off the water main valves, Bromberek balanced all of these competing concerns and chose a solution that best served the situation in his discretion (Ex. E, Bromberek Dep., pp. 147-148).

31. Fleming admitted that there was no legal mandate, rule or even a guideline that required the Village to shut off the water main valves in response to the oil leak or cleanup efforts (Ex. B, Fleming Dep., pp. 178-179; *see, also,* Ex. E, Bromberek Dep., p. 148).

32. While Fleming did not agree with Bromberek's decision, he conceded that there were factors that needed to be weighed in making that decision (Ex. B, Fleming Dep., p. 183).

33. Bromberek subsequently hired a contractor to install two new valves on the water main immediately on either side of the leak site in order to isolate and shut off the water flow to the leak site (Ex. E, Bromberek's Dep., pp. 26-28; Ex. E, Drey Dep. I, p. 46).

34. Enbridge's retained metallurgical expert, Dr. John Beavers, has opined that the metallurgical cause of the Oil Pipeline failure was a water jet from the leaking Water Service Line, combined with sand, which together formed an erosive slurry ("Water Jet Slurry") that impinged or eroded a hole in the Oil Pipeline, an occurrence which he described as "unusual" and something he had never previously encountered in 40-plus years in the industry and having conducted thousands of pipeline failure investigations; this was "new for [him]." (Ex. N, Beavers Dep., pp. 58-61).

35. Fleming agreed that the probable cause of the Oil Pipeline failure was the Water Jet Slurry, which he too described as "unusual" and "rare," and that he had never seen it happen in his career (Ex. B, Fleming Dep., pp. 30-31, 77).

36. Fleming also agreed that, prior to the leak incident, the Village did not know that there was only a 5-inch separation between the Water Service Line and the Oil Pipeline (Ex. B, Fleming Dep., pp. 75, 160-161; *see* also, Ex. E, Bromberek Dep., p. 126).

37. Fleming conceded that there was "[n]o way [Village employees] would have known" about the Water Jet Slurry or that it was impinging a hole into the Oil Pipeline (Ex. B, Fleming Dep., p. 75; *see, also,* Ex. E, Bromberek Dep., p. 126).

38. Dr. John Beavers also opined that the corrosion to the Water Service Line was caused by stray electrical currents emanating from some cathodic protection system in the area; he based this opinion on the fact that the corrosion was isolated to the top portion of the Water Service Line directly below where it crossed the Oil Pipeline; and, that the stray currents

discharged off the Water Service Line onto the Oil Pipeline at that specific location (Ex. N, Beavers Dep., pp. 18-20, 99-100).

39. Fleming agreed that the Water Service Line corroded due to stray electrical currents from a cathodic protection system of a pipeline system in the area (Ex. B, Fleming Dep., pp. 28, 40, 53, 61).

40. Prior to the leak incident, the Village did not know that stray currents were corroding or degrading the Water Service Line, or that the service line otherwise posed an unsafe condition to the Oil Pipeline (Ex. E, Bromberek Dep., pp. 126-127, 135).

41. Approximately 18 months before the leak incident, on January 22, 2009, a portion of the Water Service Line within 6-7 feet of the Oil Pipeline was uncovered and exposed during an unrelated repair of a sanitary sewer main, and there was no leak, corrosion or other defective condition observed by Village employees (Ex. O, Trobiani Dep., pp. 24-27; Ex. P, Rossio Dep., pp. 26-27, 110).

42. Public Works Director Dan Bromberek and Water Superintendent Chris Drey were responsible and empowered by the Village Board and Village Ordinances to exercise discretion over maintenance and repair of the Village's water system (Ex. M, Bromberek Aff. I, ¶¶ 4-5; Ex. E, Bromberek Dep., pp. 11-13, 135-139, 143-146; Ex. F, Drey Dep. I, pp. 6-7; Ex. Q, Drey Dep. II, pp. 95-96).

43. Bromberek and Drey exercised discretion in performing preventive maintenance activities, including leak detection and informal water audits and exercising water valves (Ex. E, Bromberek Dep., pp. 11-13, 48-49, 62-64, 88-91, 114-115, 135-139, 143-146; Ex. F, Drey Dep. I, pp. 85-87; Ex. Q, Drey Dep. II, pp. 19-20, 47-54, 76-79, 88-101).

44. In order to conduct a system-wide water audit, the Village Board of Trustees would have to approve the funding to retain (after competitive bidding) outside vendors (Ex. E, Bromberek Dep., pp. 143-144).

45. Fleming opined that the Village should have conducted water andits and then performed leak detection by sections throughout the entire Village, as recommended by the American Water Works Association ("AWWA"), to prevent the leak incident (Ex. B, Fleming Dep., pp. 102-108, 116).

46. Fleming conceded, however, that the AWWA is not a regulatory agency, and that the AWWA Manuals of Practice, which he relied upon in rendering his opinions, are *voluntary and not mandatory,* and that the Village was not bound by them (Ex. B, Fleming Dep., pp. 23-24, 37, 111, 114).

47. Fleming admitted that the Village was not legally mandated under state or federal laws to perform leak detection or water audits, or to inspect water valves (Ex. B, Fleming Dep., pp. 113-114, 127-128, 152; *see, also,* Ex. E, Bromberek Dep., pp. 138, 143-145).

48. Fleming admitted that leak detection is conducted primarily on water mains, that the AWWA Manuals do not address maintenance of lateral water service lines, and that he was not aware of any industry standard that addressed maintenance of lateral water service lines (Ex. B, Fleming Dep., pp. 111-112).

49. Fleming was not aware of any municipality that employed an ongoing leak detection system on lateral water service lines (Ex. B , Fleming Dep., pp. 111-112, 126-128, 139).

50. Fleming agreed that the Village Public Works Department and Village administration had to make budgeting and resource decisions in making improvements to and

maintaining of its waterworks system (Ex. B, Fleming Dep., pp. 120-125; *see, also,* Ex. E, Bromberek Dep., pp. 136-137).

51. At the time of the subject incident, there were over 16,000 lateral water service lines and associated stopcocks supplying potable water to residential, commercial and industrial users both within and outside of the Village's municipal boundaries (Ex. M, Bromberek Aff. I, ¶ 16; Ex. E, Bromberek Dep., pp. 134-135; Ex. Q, Drey Dep. II, p. 95).

52. It would have taken a significant amount of public resources and manpower to assume the task of performing routine leak detection services on the 16,000+ lateral water service lines or to exercise or inspect water valves (Ex. E, Bromberek Dep. pp. 135-136).

53. Decisions were made on how to allocate the Village's limited resources, and the Village did not have the financial resources or manpower to monitor or inspect every single water service line and stopcock in order to detect and/or prevent leaks (Ex. E, Bromberek Dep., pp. 137-139, 145-146; Ex. Q, Drey Dep. II, pp. 95-96).

54. Fleming agreed that the Village could not force Northfield Block to replace the Water Service Line, and that replacing a lateral water service line is very rare (Ex. B, Fleming Dep., pp. 139-141).

55. In the 15 years prior to the subject incident, the Northfield Block Water Service Line was repaired six times and, according to Fleming, three repairs occurred "in the street" under Parkwood Avenue, and the rest occurred on Northfield Block's private property (Ex. B, Fleming Dep., pp. 128-129, 132; Group Ex. R, Prior Water Service Line Repair Records).

56. According to Fleming, the repairs that occurred on Northfield Block's property were approximately 500 feet away from the street (Ex. B, Fleming Dep., p. 138).

57. The last repair on the Water Service Line "in the street" occurred in 2000, which was 10 years before the subject incident (Group Ex. R, Prior Water Service Line Repair Records).

MEMORANDUM OF LAW

ARGUMENT

I. THE VILLAGE DID NOT HAVE ACTUAL OR CONSTRUCTIVE NOTICE OF THE WATER OR OIL LEAK IN REASONABLY ADEQUATE TIME TO PREVENT THE LEAK INCIDENT AND, THEREFORE, IS NOT LIABLE FOR ENBRIDGE'S DAMAGES PURSUANT TO 745 ILCS 10/3-102 OF THE TORT IMMUNITY ACT.

Section 3-102(a) of the Illinois Tort Immunity Act provides that a municipality is not liable for the negligent maintenance of its property[1] unless it had "actual or constructive notice of the existence of such a condition that is not reasonably safe in reasonably adequate time prior to an injury to have taken measures to remedy or protect against such condition." 745 ILCS 10/3-102(a) (West 2013). Notice, therefore, is a necessary predicate for establishing liability against a municipality. *See Lansing v. McLean Cnty.*, 69 Ill. 2d 562, 572-73 (1978); *also Mark Twain Illinois Bank v. Clinton County*, 302 Ill. App. 3d 763 (5th Dist. 1999). "The burden of proving notice is on the party charging it." *Perfetti v. Marion Cnty.*, 2013 IL App (5th) 110489, ¶ 19 (*quoting Burke v. Grillo*, 227 Ill. App. 3d 9, 18 (1992)). "Although the issue of notice is normally one of fact, it becomes a question of law which may be determined by the court if all of the evidence, when viewed in the light most favorable to the plaintiff, so overwhelmingly favors the defendant public entity that no contrary verdict could stand." *Perfetti, id.*

[1] It is the Village's position in this litigation that it did not own the land beneath Parkwood Avenue or Water Service Line, and it had no duty to maintain the Water Service Line. However, those issues are not the subject of this motion and need not be resolved in this motion because the Village is otherwise immune from liability, as argued herein. *DeSmet ex rel. Estate of Hays v. Cnty. of Rock Island*, 219 Ill. 2d 497, 509 (2006) ("so may we assume a defendant owes a duty, for the sake of analysis, in order to expedite the resolution of an immunity issue"); *also Prough v. Madison Cnty.*, 2013 IL App (5th) 110146, ¶ 18.

Here, there is no evidence of actual notice. Enbridge's retained civil engineering expert, Peter Fleming, conceded that the Village did not have notice of the water leak until 9:36 a.m. on September 9, 2010, and that oil was not observed until a few hours later (Village Stmt. of Facts, ¶¶ 7-8, 18-19). In fact, the Village's first actual notice of the oil leak was when Romeoville police and fire officials responded to a 911 call about a gas odor at 12:05 p.m. (*id.* ¶¶ 21-22). Not even Enbridge's sophisticated computer leak detection system detected the oil leak; rather Enbridge had to be notified of the leak by Romeoville Assistant Fire Chief Ed Panzer (*id.* ¶ 23).

Furthermore, according to both Fleming and Enbridge's metallurgical expert, John Beavers, the cause of the oil leak was the Water Jet Slurry impinging or eroding a hole into the Oil Pipeline, which both described as "unusual" and "rare" and an occurrence that neither had ever encountered in their respective careers. (*id.* ¶¶ 34-35). Indeed, Fleming conceded that the Village did not know prior to the leak incident that there was only a 5" separation between the pipelines, and he conceded that there was "[n]o way [village employees] would have known" about the Water Jet Slurry or its impingement on the Oil Pipeline. (*id.* ¶¶ 36-37).

Both Fleming and Beavers also opined that the Water Service Line had corroded due to stray current corrosion from some cathodic protection source in the area. (*id.* ¶¶ 38-39). The Village's Public Works Director, Dan Bromberek, testified that the Village had no knowledge that the Water Service Line was corroding, let alone that stray currents were causing the corrosion. (*id.* ¶ 40). In fact, approximately 18 months before the September 9, 2010 leak incident, a portion of the Water Service Line only 6-7 feet west of the Oil Pipeline had been exposed in connection with an unrelated repair of a sanitary sewer line, and there was no corrosion, leak or other defective or unsafe condition observed by Village Public Works employees (*id.* ¶ 41). Based on these facts, the only possible conclusion that a jury could reach is that the Village did not have actual notice of any unsafe condition in reasonably adequate time to take action to prevent the leak incident.

That leaves Enbridge with proving constructive notice. To do so, Enbridge must prove that an unsafe condition existed for such a length of time or was so conspicuous that the Village should have known about it. *See Pinto v. DeMunnick*, 168 Ill. App.3d 771, 774 (1st Dist. 1988); *Siegel v. Vill. Of Wilmette*, 324 Ill. App.3d 903, 908 (1st Dist. 2001); *Burke*, 227 Ill. App.3d at 18. Obviously, the alleged unsafe condition was inconspicuous as it occurred 7 feet below the surface of the street (Village Stmt. of Facts, ¶ 5). There is no evidence that the Village knew or should have known that this event was occurring over any period of time. Even Enbridge's experts, Beavers and Fleming, admitted how "rare" and "unusual" this occurrence was. As stated above, the last time that the Water Service Line was exposed, approximately 18 months before the leak incident, the Water Service Line was in good condition and was not corroding or leaking water. (*id.* ¶ 41). Under these undisputed facts, no reasonable jury could ever conclude that the Village had constructive knowledge of any unsafe condition. *See Siegel*, *id.* (holding that there was no constructive notice of sidewalk defect because a village inspection just over year before incident found no defect or need for repair).

In its Second Amended Complaint, Enbridge alleges that the Water Service Line had a history of leakage based on prior repairs over a 15 year period (Ex. A, Sec. Am. Compl., ¶ 7). However, this allegation is irrelevant as a matter of law. "Section 3-102(a) requires proof that the defendant had timely notice of the *specific defect* that caused the plaintiff's injuries, not merely the condition of the area." *Zameer v. City of Chicago*, 2013 IL App (1st) 120198, ¶16. In *Zameer*, the plaintiff contended that the municipality had actual or constructive notice of the defect that caused her injuries – a two-inch height difference in the sidewalk – based on the multiple prior complaints about the general condition of the sidewalk along the same block. 2013 IL App (1st) 120198, ¶ 17. In affirming summary judgment for the city, the Appellate Court rejected this argument, noting that there was no evidence of prior complaints about the *specific defect* that caused the plaintiff's injuries and, therefore "the [condition of the] surrounding area [was] irrelevant." *Id.* at ¶ 17, 23.

Other courts have reached similar conclusions. *See*, *e.g.*, *Perfetti* (holding that knowledge that a dangerous condition *could* occur on a stretch of highway is not sufficient notice of a dangerous condition at the location where the plaintiff was injured); *Brzinski v. Northeast Ill. Reg'l. Commuter R.R. Corp.*, 384 Ill. App. 3d 202, 206 (2008) (the presence of sinkholes in the general area is insufficient to establish constructive notice); *Pinto*, 168 Ill. App. 3d 771 (knowledge that sinkholes were a "common problem" within the municipal drainage system did not establish notice about the sinkhole that caused plaintiff's accident); *Harms v. Vill. of Romeoville*, 2011 IL App (3d) 100858-U, ¶ 10 (granting summary judgment for village based on lack of notice of the particular sidewalk defect that caused plaintiff's injuries); *Gleason v. City of Chicago*, 190 Ill. App.3d 1068, 1070 (1st Dist. 1989) (the presence of broken or cracked sidewalk slabs in the area was irrelevant to the cause of the plaintiff's fall because she testified that she stubbed her toe on a ¼ inch crack and therefore the general condition of the surrounding are did not cause her fall).

In the instant case, according to Enbridge's experts, the cause of the water leak was stray current corrosion which led to the Water Jet Slurry which led to the impingement or erosion of a hole in the Oil Pipeline (Village Stmt. of Facts, ¶¶ 38-39). According to Beavers, these mechanisms were possible ***only*** because the Water Service Line and the Oil Pipeline crossed in close proximity to each other (*id.*). In other words, the corrosion occurred ***only*** because the Oil

Pipeline provided the return path for the stray currents, and the impingement or erosion occurred ***only*** because of the close proximity of the pipes to each other (*id.*). Under *Zameer* and the other cases cited above, therefore, the general conditions elsewhere on the Water Service Line did not cause the leak incident and are irrelevant. Thus, as a matter of law, the prior repair history of the Water Service Line could not, and did not, put the Village on notice of the specific condition that caused Enbridge's injuries.

Furthermore, in forming his opinions, Fleming relied on three repairs that he claimed occurred "in the street." (Village Stmt. of Facts, ¶¶ 55-56). The last of these repairs, however, occurred in November of 2000 - *10 years* before the September 9, 2010 leak incident. (*id.* ¶ 57). In other words, in the 10 years before the leak incident, there were no repairs of the Water Service Line "in the street." Thus, no reasonable jury could ever conclude that the Village should have known of any unsafe condition in a reasonably adequate period of time to remedy it – particularly when the condition was caused by invisible, inconspicuous electrical currents and a Water Jet Slurry occurring seven feet below the surface of Parkwood Avenue.

Finally, Enbridge faults the Village for failing to maintain the stopcock, which allegedly malfunctioned within hours after the oil leak was discovered. The undisputed fact is that Village Public Works employee, Dale Wills, successfully turned the stopcock without any problems just a few hours before the oil leak was reported. (Village Stmt. of Facts, ¶¶ 9-11). It was only later, in the throes of an undisputed emergency after the Village and Enbridge learned about the oil leak, that the stopcock allegedly malfunctioned – which was the first notice of any problem. (id. ¶¶ 24-25). The Village simply had no notice, actual or constructive, that the stopcock was unsafe in a reasonably adequate period of time to remedy or prevent the oil leak.

II. THE VILLAGE IS ENTITLED TO DISCRETIONARY IMMUNITY PURSUANT TO SECTION 2-201 OF THE TORT IMMUNITY ACT

Under § 2-201 of the Illinois Tort Immunity Act, "a public employee serving in a position involving the determination of policy or the exercise of discretion is not liable for an injury resulting from his act or omission in determining policy when acting in the exercise of discretion, even though abused." 745 ILCS 10/2-201 (West 2014). Section 2-201 has two parts: (1) the position held by the municipal employee must involve a determination of policy *or* the exercise of discretion; and, (2) the employee's decision must be both a determination of policy *and* an exercise of discretion. *See Harinek v. 161 North Clark St. Ltd. Partnership*, 181 Ill. 2d 335, 341 (1998). Section 2-201 "extends the most significant protection afforded public employees under the Act." *Van Meter v. Darien Park Dist.*, 207 Ill. 2d 359, 370 (2003).[2]

"Discretionary acts involve the exercise of personal deliberation and judgment in deciding whether to perform a particular act or how and in what manner that act should be performed." *Richter v. Coll. of DuPage*, 2013 IL App (2d) 130095, ¶43 (*quoting Trtanj v. City of Granite City*, 379 Ill. App. 3d 795, 803 (5th Dist. 2008)). "Discretionary acts are 'those which are unique to the particular public office,' whereas ministerial acts that are 'those which a person performs on a given state of facts in a prescribed manner, in obedience to the mandate of legal authority, and without reference to the official's discretion as to the propriety of the act.'" *Id.* (*quoting Kevin's Towing, Inc. v. Thomas*, 351 Ill. App. 3d 540, 547 (2d Dist. 2004)).

Policy determinations require a public employee to balance competing interests and to make a judgment call as to what solution will best serve each of those interests. *West v.*

[2] Under § 2-109 of the Tort Immunity Act, "[a] local public entity is not liable for an injury resulting from an act or omission of its employee where its employee is not liable." 745 ILCS 10/2-109 (West 2014). Together, §§ 2-109 and 2-201 provide broad discretionary immunity to public entities and their officials. *See Arteman v. Clinton Cmty. Unit Sch. Dist. No. 15*, 198 Ill. 2d 475, 484 (2002).

Kirkham, 147 Ill. 2d 1, 11 (1992). Several factors must be considered in determining policy, including "the public benefit, the practicability of the plan or procedure, and the best methods to be employed considering resources, costs, and safety." *Wrobel v. City of Chicago*, 318 Ill. App. 3d 390, 394 (1st Dist. 2000). While a municipality is not immune for the actual performance of ministerial tasks, immunity is available for the determination of policy and exercise of discretion in deciding how and when those tasks are to be performed. *See Robinson v. Washington Twp.*, 2012 IL App (3d) 110177, ¶ 11 (2012); *see, also, Kennell v. Clayton Twp.*, 239 Ill. App. 3d 634, 640 (4th Dist. 1992).

Recently, in *Nichols v. City of Chicago Heights*, 2015 IL App (1st) 122994 (2015), the Appellate Court addressed the application of § 2-201 discretionary immunity to the maintenance of municipal utility systems. In *Nichols*, the plaintiff homeowners whose homes had been damaged by flooding caused by sewer overflow, sued the City of Chicago Heights and several of its officials and employees. The Court reaffirmed that "[w]hether a municipality engages in a program of public improvement is a discretionary matter, but the manner in which the municipality implements the program is ministerial." *Id.* at ¶ 31. The plaintiffs had asked the Court "to determine that the City's conduct as a whole in regard to the maintenance and upkeep of its sewer systems prior to the occurrence period was ministerial." *Id.* at 33. The Appellate Court rejected the plaintiffs' argument and found that the "the trial court properly ruled that the city is immune from plaintiffs' claims of negligence where the decisions the City made regarding the maintenance and improvement of its sewer system were discretionary in nature." *Id.*

In rendering its decision, the Appellate Court in *Nichols* relied on *Donovan v. Cnty. of Lake*, 2011 IL App (2d) 100390 (2011). In *Donovan*, the plaintiffs sued Lake County for failing to chlorinate the public water system as required by the Illinois Environmental Protection

Agency and thereby allowing excessive amounts of bacteria into the water supply. The Appellate Court affirmed dismissal of the suit, finding that, even though the County was legally mandated to chlorinate the water and provide safe drinking water, the manner in which it carried out, or failed to carry out, that duty, including whether to repair and/or rebuild the system at the public's cost, invoked discretionary and involved policy decisions. *Id.* at ¶ 62.

The Appellate Court's decision in *Herrington, Inc. v. City of Geneva*, 2012 IL App (2d) 120131-U, is also on point. In that case, a hotel owner sued a city for flood damage. During a recent storm, water had apparently pooled in a city-owned storm water basin on the west side of the hotel, and the storm drain in the basin was covered by soils. The owner alleged that the city had negligently operated and maintained the storm sewers that serviced the hotel and failed to inspect the system for blockage and to clean it out. The Appellate Court affirmed summary judgment in favor of the city based on discretionary immunity. *Id.* at ¶ 50. The city's public works director had testified that he determined when and how to inspect and maintain the city's sewers, and that he did not have the manpower or resources to inspect all sewers. *Id.* at ¶ 57. Thus, he had to make policy decisions on how to best allocate his resources and, as a result, had to prioritize those inspections and maintenance activities. *Id.* The Court held that the city's acts or omissions in maintaining the sewer system, specifically how it went about inspecting the system, involved both a policy determination and the exercise of discretion. *Id.*

In the instant case, the Village's Public Works Director, Dan Bromberek, and Water Superintendent, Chris Drey, were empowered to exercise discretion over the maintenance of the Village's water system. (Village Stmt. of Facts, ¶ 42). Both enjoyed the discretion to decide if, how and when to perform preventive maintenance activities, including leak detection, inspecting water valves, and conducting informal focused water audits. *(id.*, ¶ 43). With regard to formal, system-wide water audits, the Village Board had the authority and discretion to approve funding to retain (after competitive bidding) outside vendors to perform that work. (*id.*, ¶ 44). Thus, it is undisputed that Bromberek and Drey, as well as members of the Village Board, served in positions that involved both the determination of policy and/or the exercise of discretion relative to the maintenance of the Village's water system.

Enbridge's retained civil engineering expert, Peter Fleming, opined that the Village should have conducted water audits and leak detection based on the AWWA recommended practices and that, had it done so, it would have prevented the leak. (Village Stmt. of Facts, ¶ 45). However, he conceded that performing such preventive maintenance was not legally mandated, and that the AWWA practices are merely voluntary and that *the Village was not bound by them.* (*id.* ¶¶ 46-47). Fleming was also unaware of any law, standard or practice that addressed the maintenance of lateral water service lines (*id.* ¶¶ 48-49). Thus, similar to *Nichols, Donovan* and *Herrington*, when and how the Village carried out its alleged duty to maintain its water distribution system (of which the Northfield Block Water Service Line was a part, according to Enbridge), was discretionary and not mandated by any law, regulation, or even recommended industry practices. Fleming also conceded that the Village had to make budgetary decisions and allocate resources in maintaining its water distribution system (Village Stmt. of Facts, ¶ 50). Indeed, there were over 16,000 later water service lines within the Village system, and it would have taken a significant amount of public resources to assume the task of performing leak detection on all of those lines (*id.* ¶¶ 51-52). Bromberek and Dry testified that they made decisions in maintaining the water works system based on the resources made available to them by the Village Board of Trustees (*id.* ¶¶ 53-54). Thus, under the above-cited case law, Section 2-201 squarely applies to this case and immunizes the Village completely from liability for

Enbridge's damages. *See, also, In re Chicago Flood Litigation*, 176 Ill. 2d 179 (1997) (§2-201 immunity for decision as to where to make repairs to flood control improvements); *Richter*, 2013 IL App (2d) 130095 (decision as to how and when to repair sidewalk was discretionary and a matter of policy); *Wrobel v. City of Chicago*, 318 Ill. App. 3d 390 (1st Dist. 2000) (laborer's decision *how* to fill potholes involved policy and discretion).

Enbridge also alleges that the Village was negligent in turning the water back on after discovering the water leak.[3] However, this decision was part of a plan to address the water leak put in place by Wills and his supervisor Chris Drey. Once the water leak was discovered, Wills turned off the water and saw the water recede and suspected that the leak was on the water line. He contacted Northfield Block who hired a leak detection company. (Village Stmt. of Facts, ¶ 7). Wills turned the water back on, in part, so that the leak detection company could find the leak. (*id.*, ¶¶ 10-12). While Fleming did not agree with this decision, he admitted that the water needed to be flowing for the company to locate the leak, that there was no rule or guideline that mandated that Wills keep the water off, and that Wills had to make a judgment call in this situation. (*id.*, ¶¶ 12-16). Section 2-201 discretionary immunity controls this decision and immunizes the Village from liability. *See Richter*, 2013 IL App (2d) 130095 (school building manager's plan as to when and how to repair a sidewalk was discretionary and a matter of policy for purposes of § 2-201 immunity).

Finally, the decision *not* to shut down the water main in response to the oil leak also fell squarely within the scope of § 2-201 immunity. Public Works Director Dan Bromberek was not only empowered to exercise discretion over the water system, he was authorized specifically to make decisions in response to the oil leak. (Village Stmt. of Facts, ¶ 26). Bromberek's main

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[3] Enbridge offers no evidence that this decision caused or contributed to the oil leak. Indeed, Fleming admitted that he had no such opinion. (Village Stmt. of Facts, ¶ 20).

concern was contaminating the Village-wide water system. (*id.* ¶¶ 27-29). He testified that the cost to remedy such contamination would have been significant. (*id.* ¶ 28). Bromberek balanced all of these competing concerns and chose, in his discretion, a solution that best served the situation (*id.* ¶ 30). While Enbridge's expert, Peter Fleming, disagreed with Bromberek's decision, he conceded that there was no legal mandate governing this decision, and that Bromberek made a judgment call after weighing the factors present at the time (*id.* ¶ 32). This decision considered "the public benefit, the practicability of the plan or procedure, and the best methods to be employed considering resources, costs, and safety." *See Wrobel*, 318 Ill. App. 3d at 394. Bromberek's decision was quintessentially one of policy and discretion warranting immunity under § 2-201 of the Tort Immunity Act.

CONCLUSION

For the foregoing reasons, the Defendant, Village of Romeoville, is immune from liability and is entitled to summary judgment in its favor on the entirety of Plaintiff Enbridge Energy Ltd.'s second amended complaint.

Respectfully submitted,

MICHAEL D. BERSANI, *One of the Attorneys for Defendant*, VILLAGE OF ROMEOVILLE

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STATE OF ILLINOIS)
)SS
COUNTY OF WILL)

IN THE CIRCUIT COURT OF THE TWELFTH JUDICIAL CIRCUIT
WILL COUNTY, ILLINOIS

ENBRIDGE
Plaintiff
VS
Old Castle
Defendant

CASE NO: 11 L 727

COURT ORDER

This Matter Coming to be heard for ruling on Village's Renewed Motion for Summary Judgment and hearing on cross motions for sanctions and Enbridge's motion to set trial date, and the Court being fully advised in the premises,

It is Hereby Ordered:

(1) Village's Renewed Motion for summary judgment is granted for the reasons stated in open court

(2) the cross motions for sanctions are entered and continued generally until next status hearing of August 26, 2016 at 9:30 a.m.

(3) Enbridge's motion to set trial is entered and continued to August 26, 2016 at 9:30 AM

(4) this case is continued to August 26, 2016 at 9:30 am for status.

Attorney or Party, if not represented by Attorney
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Dated: August 10, 2016

Entered: [signature]
Judge

PAMELA J. MCGUIRE, CLERK OF THE CIRCUIT COURT OF WILL COUNTY

Line 3 Replacement Project (U.S.)

Line 3 is an existing 1,097-mile crude oil pipeline, originally installed in the 1960s, that extends from Edmonton, Alberta to Superior, Wisconsin, and is an integral part of Enbridge's Mainline System.

The Line 3 Replacement Program is an integrity and maintenance driven project, and spans from Hardisty, Alberta to Superior, Wisconsin and consists of 1,031 miles of 36-inch diameter pipeline. The U.S. portion of the Line 3 Replacement Program (from Neche, North Dakota, through Minnesota, to Superior, Wisconsin) is referred to as the Line 3 Replacement Project.

Safe and reliable operations are the foundation of Enbridge's business, and maintaining pipeline safety through the integrity management program is essential. As part of our routine maintenance program, Enbridge conducted an assessment of the Line 3 pipeline in 2013. The assessment identifies strategic and efficient means for maintaining system integrity, including additional in-line tool runs, investigatory digs or segment replacement. Enbridge further determined that a replacement of Line 3 was best to maintain system integrity while minimizing disruption to landowners and communities.

The proposed 36-inch replacement pipeline will serve the same purpose as the existing Line 3, which is the transportation of crude oil from Canada to the Enbridge Clearbrook Terminal near Clearbrook, Minnesota and on to Enbridge's Superior Station and Terminal Facility near Superior, Wisconsin. The replacement pipeline will restore the hi[illegible] capabilities of Line 3, and is generally expected to serve the same markets, and transport the same product mix as the current Line 3. The line is physically equipped to transport all grades of crude oil, and the type of crude oil transported in the future (as in the past) will be based on shipper demand. Upon replacement, the average annual capacity of Line 3 will be 760 kbpd.

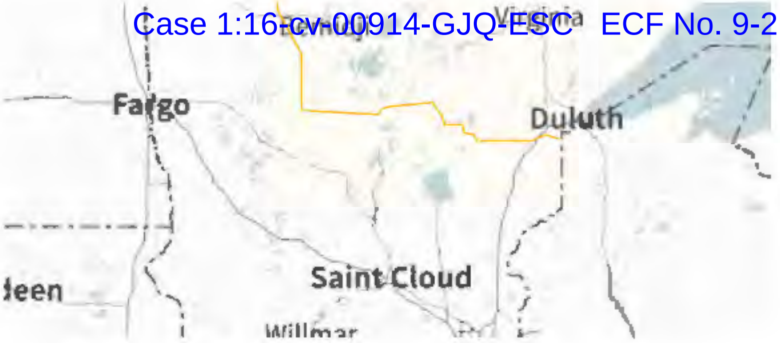
Line 3 Project Summary (/~/media/Rebrand/Documents/Projects/US/ENBLine3Public AffairsProject SummaryFINALemail.pdf?la=en)

CONTACTS:

We welcome your feedback. Please contact us with questions and/or comments; we will promptly respond to your inquiry.

Call toll-free: 1-855-788-7805

Email: EnbridgeinMN@enbridge.com (mailto:EnbridgeinMN@enbridge.com)



VIEW MAP +

(HTTP://WWW.ENBRIDGE.COM/MAP#MAP:PROJECTS,SEAF

PROJECT OVERVIEW:

Type: Crude oil pipeline
Status:Proposed
Length: 1,031 miles (1,659 km)
Expected initial capacity: 760,000 barrels per day
Estimated to transport: Light, medium and heavy crude
Estimated capital cost: $7.5 billion

LINE 3 REPLACEMENT PROGRAM

The $7.5-billion Line 3 Replacement Program (L3RP), running from Hardisty, AB to Superior, WI, is the argest project in Enbridge history.

LEARN MORE +

(/PROJECTS-AND-INFRASTRUCTURE/PROJECTS/LINE-3-REPLACEMENT-PROGRAM)

Minnesota Projects Website

Project Information:

PROJECT SCOPE (/ PRO…

MAPS ✚ (/ PROJECTS-AND-…

TIMELINE ✚ (/ PROJECTS-A…

Project Scope

The Line 3 Replacement Program is an approximate $7.5 billion private investment, making it one of North America's largest infrastructure programs. Under the Line 3 Replacement (L3R) Project ($2.6 billion investment in the U.S.), the majority of the existing Line 3 will be fully replaced with new 36-inch diameter pipeline and associated facilities from Neche, North Dakota to Superior, Wisconsin. This includes about 13 miles in North Dakota, 337 miles in Minnesota, and 14 Miles in Wisconsin. The Project will include construction of four new pump stations, upgrades to four existing pump stations and approximately 27 strategically placed valves. Segments of Line 3 from the Canadian border to Neche, ND and near the Minnesota/Wisconsin border to the Superior terminal are being replaced under separate segment replacement projects.

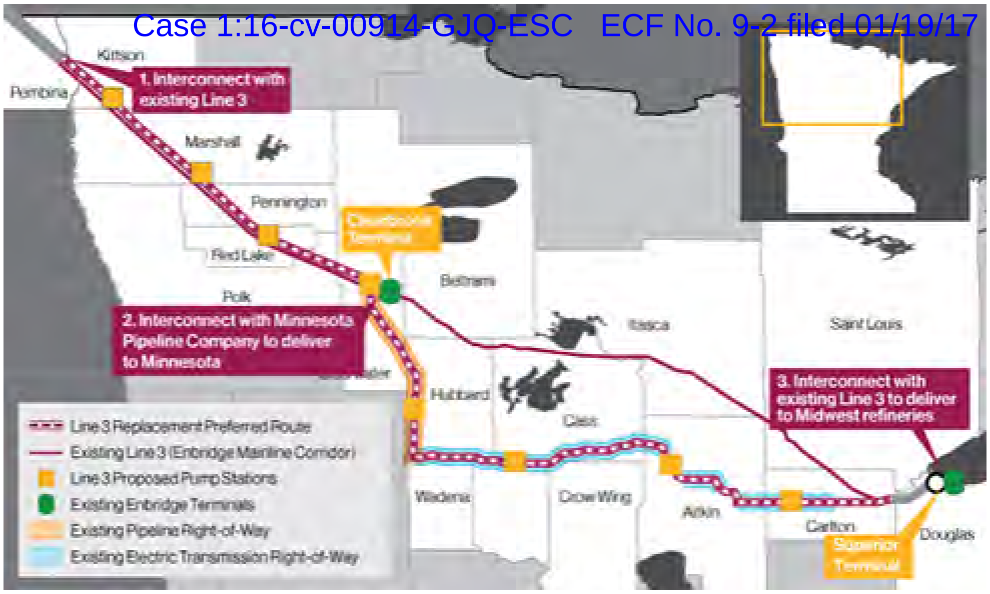
In the U.S. the L3R Project is comprehensively regulated at both federal and state levels – including the U.S. Army Corps of Engineers, as well as state regulators (North Dakota Public Service Commission, Minnesota Public Utilities Commission, and Public Service Commission of Wisconsin). Various other applicable federal and state environmental permitting agencies will be involved in the environmental review and analysis of the L3R Project.

Preferred Route Selection Process

Enbridge developed the Project's preferred route based on its extensive pipeline routing experience, knowledge of applicable federal and state regulations, as well as agency, landowner and other input.

Enbridge first considered where the Project must enter, deliver within, and exit Minnesota in order to meet the needs of shippers served by Line 3. Enbridge next identified and analyzed routing constraints and opportunities, and identified and analyzed route alternatives.

Once a general route location was identified, Enbridge conducted detailed environmental and engineering survey work to further refine the route to avoid or minimize human and environmental impacts, as well as identify appropriate mitigation measures to limit potential impacts during Project construction and operation. The resulting preferred route meets the Project's purpose, maximizes opportunities for colocating within a utility corridor, and minimizes potential impacts.



Preferred Route Selection Process Handout (~/media/867527C90FE344B797B5926A5E15CF0A.ashx)

Environmental Protection

The Project route, facility design, and construction procedures have been designed to minimize impacts on the environment. Environmental impacts related to construction of the pipeline will primarily be related to temporary disturbance to land, wetlands, and waterbodies. Environmental impacts related to operations of the pipeline will primarily be related to maintenance repairs and mowing activities.

In 2014, Enbridge started working with federal, state, and local regulatory agencies to design Project plans and permit conditions to minimize impacts to the environment. Enbridge has already committed to a variety of resource-specific mitigation measures, which are detailed in Section 7 of the Route Permit. Enbridge will retain environmental inspectors (EIs) during Project construction who will be responsible for understanding all regulatory requirements and permit conditions, and ensuring that contractors abide by these conditions The Project will also be supervised by third-party environmental monitors who will report any concerns directly to appropriate agencies.

Protection

- Although much of the pipeline will be routed along existing Enbridge or other utility right-of-way, new rights-of-way will be required.
- Extensive environmental surveys and field studies will be conducted to evaluate:
  - wetlands and water bodies,
  - threatened and endangered species habitats, and
  - archaeological/cultural resources.
- Environmental management practices during construction will minimize short term disruption and long term impacts to land.
- Construction, safety, and environmental inspectors will be present during construction to monitor compliance with specifications, permits, and landowner agreements.
- Enbridge will develop and implement project-specific environmental protection plans, as required for the regulatory approval.

Restoration

- Enbridge will restore land as near as is practicable to its preconstruction condition
- Landowners will be notified prior to access or work on their property.
- During construction Enbridge will use modern land restoration techniques to prevent soil erosion, protect agricultural topsoil, repair agricultural drain tiles and irrigation systems, and alleviate soil compaction.
- A Project right-of-way representative will contact landowners to confirm restoration was completed and/or that compensation was handled according to agreements with Enbridge.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2014

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**39-1715850**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**

1100 Louisiana
Suite 3300
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

(713) 821-2000
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☒	Accelerated Filer ☐
Non-Accelerated Filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The registrant had 254,208,428 Class A common units outstanding as of August 1, 2014.

ENBRIDGE ENERGY PARTNERS, L.P.

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In this report, unless the context requires otherwise, references to "we," "us," "our," "EEP" or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We refer to our general partner, Enbridge Energy Company, Inc., as our "General Partner."

This Quarterly Report on Form 10-Q includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "should," "strategy," "target," "will" and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Any forward-looking statement made by us in this Quarterly Report on Form 10-Q speaks only as of the date on which it is made, and we undertake no obligation to publicly update any forward-looking statement. Many of the factors that will determine these results are beyond the Partnership's ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include: (1) changes in the demand for, the supply of, forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids, or NGLs, including the rate of development of the Alberta Oil Sands; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline systems; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to which we sell products; (5) hazards and operating risks that may not be covered fully by insurance, including those related to Line 6B and any additional fines and penalties assessed in connection with the crude oil release on that line; (6) changes in or challenges to our tariff rates; and (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance.

For additional factors that may affect results, see "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013 and our subsequently filed Quarterly Reports on form 10-Q, which is available to the public over the Internet at the U.S. Securities and Exchange Commission's, or SEC's, website (www.sec.gov) and at our website (www.enbridgepartners.com).

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(unaudited; in millions, except per unit amounts)			
Operating revenue (Note 10)	$1,785.1	$1,603.9	$3,789.6	$3,226.3
Operating revenue—affiliate (Note 8)	86.0	68.8	161.1	139.4
	1,871.1	1,672.7	3,950.7	3,365.7
Operating expenses:				
Cost of natural gas (Notes 4 and 10)	1,221.4	1,081.0	2,679.9	2,234.4
Cost of natural gas—affiliate (Note 8)	38.4	34.5	68.6	72.5
Environmental costs, net of recoveries (Note 9)	38.2	5.2	43.2	183.7
Operating and administrative	107.3	113.3	203.9	195.3
Operating and administrative—affiliate (Note 8)	117.3	104.7	237.7	217.6
Power (Note 10)	54.2	29.2	104.6	62.8
Depreciation and amortization	113.4	95.8	217.2	188.0
	1,690.2	1,463.7	3,555.1	3,154.3
Operating income	180.9	209.0	395.6	211.4
Interest expense, net (Notes 6 and 10)	80.2	79.5	157.1	155.9
Allowance for equity used during construction (Note 13)	12.6	8.1	33.3	15.9
Other income	1.2	0.3	0.4	0.6
Income before income tax expense	114.5	137.9	272.2	72.0
Income tax expense (Note 11)	2.0	14.2	4.0	16.0
Net income	112.5	123.7	268.2	56.0
Less: Net income attributable to:				
Noncontrolling interest (Note 8)	42.4	18.4	78.7	34.0
Series 1 preferred unit distributions (Note 7)	22.5	13.1	45.0	13.1
Accretion of discount on Series 1 preferred units (Note 7)	3.7	2.3	7.3	2.3
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 43.9	$ 89.9	$ 137.2	$ 6.6
Net income (loss) allocable to limited partner interests	$ 5.0	$ 56.7	$ 63.9	$ (56.2)
Net income (loss) per limited partner unit (basic) (Note 2)	$ 0.02	$ 0.18	$ 0.19	$ (0.18)
Weighted average limited partner units outstanding (basic)	327.6	314.8	327.0	311.0
Net income (loss) per limited partner unit (diluted) (Note 2)	$ 0.02	$ 0.18	$ 0.19	$ (0.18)
Weighted average limited partner units outstanding (diluted)	327.6	314.8	327.0	311.0

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(unaudited; in millions)			
Net income	$112.5	$123.7	$ 268.2	$ 56.0
Other comprehensive income (loss), net of tax expense of $0.0 million $0.1 million, $0.0 million and $0.1 million, respectively (Note 10)	(66.0)	162.0	(136.1)	191.7
Comprehensive income	46.5	285.7	132.1	247.7
Less: Comprehensive income attributable to:				
Noncontrolling interest (Note 8)	42.4	18.4	78.7	34.0
Series 1 preferred unit distributions (Note 7)	22.5	13.1	45.0	13.1
Accretion of discount on Series 1 preferred units (Note 7)	3.7	2.3	7.3	2.3
Other comprehensive income (loss) attributed to noncontrolling interest	(0.3)	—	(0.3)	—
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (21.8)	$251.9	$ 1.4	$198.3

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the six month period ended June 30, 2014	2013
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 268.2	$ 56.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	217.2	188.0
Derivative fair value net losses (gains) (Note 10)	24.7	(22.3)
Inventory market price adjustments (Note 4)	3.3	2.5
Environmental costs, net of recoveries (Note 9)	38.0	179.7
Distributions from investments in joint ventures (Note 8)	1.0	—
Equity earnings from investments in joint ventures (Note 8)	(1.0)	—
Deferred income taxes (Note 11)	1.3	13.2
State income taxes	1.8	7.4
Allowance for equity used during construction (Note 13)	(33.3)	(15.9)
Other	(0.8)	7.3
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	9.1	60.1
Due from General Partner and affiliates	5.3	4.5
Accrued receivables	51.8	276.3
Inventory (Note 4)	(75.7)	(95.1)
Current and long-term other assets (Note 10)	(16.5)	(19.1)
Due to General Partner and affiliates	(6.0)	18.4
Accounts payable and other (Notes 3 and 10)	(63.8)	(40.3)
Environmental liabilities (Note 9)	(62.9)	(32.7)
Accrued purchases	(3.2)	(95.3)
Interest payable	1.4	4.1
Property and other taxes payable	(1.6)	(14.0)
Settlement of interest rate derivatives (Note 10)	1.3	(5.3)
Net cash provided by operating activities	359.6	477.5
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 5 and 14)	(1,309.0)	(859.7)
Changes in restricted cash (Note 8)	36.1	(3.4)
Investments in joint ventures (Note 8)	(28.1)	(126.7)
Distributions from investments in joint ventures in excess of cumulative earnings	17.7	—
Other	(3.7)	(4.0)
Net cash used in investing activities	(1,287.0)	(993.8)
Cash provided by financing activities:		
Net proceeds from Series 1 preferred unit issuance (Note 7)	—	1,200.0
Net proceeds from unit issuances (Note 7)	—	278.7
Distributions to partners (Note 7)	(356.9)	(353.3)
Repayments to General Partner (Note 8)	(6.0)	(6.0)
Repayments of long-term debt (Note 6)	—	(200.0)
Net borrowings under credit facility (Note 6)	140.0	—
Net commercial paper borrowings (repayments) (Note 6)	765.0	(724.7)
Contributions from noncontrolling interest (Notes 7 and 8)	612.9	149.7
Distributions to noncontrolling interest (Notes 7 and 8)	(42.5)	(28.7)
Net cash provided by financing activities	1,112.5	315.7
Net increase (decrease) in cash and cash equivalents	185.1	(200.6)
Cash and cash equivalents at beginning of year	164.8	227.9
Cash and cash equivalents at end of period	$ 349.9	$ 27.3

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2014	December 31, 2013
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 3)	$ 349.9	$ 164.8
Restricted cash (Note 8)	33.3	69.4
Receivables, trade and other, net of allowance for doubtful accounts of $0.5 million in 2014 and 2013 (Note 9)	51.7	49.4
Due from General Partner and affiliates	36.5	40.5
Accrued receivables	147.0	210.2
Inventory (Note 4)	164.9	94.9
Other current assets (Note 10)	58.7	47.6
	842.0	676.8
Property, plant and equipment, net (Note 5)	14,207.1	13,176.8
Goodwill	246.7	246.7
Intangibles, net	257.7	263.2
Other assets, net (Note 10)	509.9	538.0
	$16,063.4	$14,901.5
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 8)	$ 118.1	$ 121.4
Accounts payable and other (Notes 3, 10 and 13)	710.9	822.0
Environmental liabilities (Note 9)	187.7	233.7
Accrued purchases	457.4	465.6
Interest payable	69.4	68.0
Property and other taxes payable (Note 11)	68.8	70.7
Note payable to General Partner (Note 8)	12.0	12.0
Current maturities of long-term debt (Note 6)	200.0	200.0
	1,824.3	1,993.4
Long-term debt (Note 6)	5,682.7	4,777.4
Loans from General Partner and affiliate (Note 8)	300.0	306.0
Due to General Partner and affiliates (Note 8)	103.3	58.2
Deferred income tax liability (Note 11)	18.7	17.4
Other long-term liabilities (Notes 9 and 10)	136.4	51.7
Total liabilities	8,065.4	7,204.1
Commitments and contingencies (Note 9)		
Partners' capital: (Notes 7 and 8)		
Series 1 preferred units (48,000,000 at June 30, 2014 and December 31, 2013)	1,168.0	1,160.7
Class A common units (254,208,428 at June 30, 2014 and December 31, 2013)	2,755.5	2,979.0
Class B common units (7,825,500 at June 30, 2014 and December 31, 2013)	58.5	65.3
i-units (66,196,781 and 63,743,099 at June 30, 2014 and December 31, 2013, respectively)	1,305.1	1,291.9
General Partner	298.9	301.5
Accumulated other comprehensive income (loss) (Note 10)	(212.4)	(76.6)
Total Enbridge Energy Partners, L.P. partners' capital	5,373.6	5,721.8
Noncontrolling interest (Note 8)	2,624.4	1,975.6
Total partners' capital	7,998.0	7,697.4
	$16,063.4	$14,901.5

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP, for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of June 30, 2014, our results of operations for the three and six month periods ended June 30, 2014 and 2013, and our cash flows for the six month periods ended June 30, 2014 and 2013. We derived our consolidated statement of financial position as of December 31, 2013, from the audited financial statements included in our Annual Report on Form 10 K for the fiscal year ended December 31, 2013. Our results of operations for the six month period ended June 30, 2014, should not be taken as indicative of the results to be expected for the full year due to seasonal fluctuations in the supply of and demand for crude oil, seasonality of portions of our natural gas business, timing and completion of our construction projects, maintenance activities, the impact of forward commodity prices and differentials on derivative financial instruments that are accounted for at fair value and the effect of environmental costs and related insurance recoveries on our Lakehead system. Our unaudited interim consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Comparative Amounts

During the first quarter of 2014, we changed our reporting segments. The Marketing segment was combined with the Natural Gas segment to form one new segment named “Natural Gas.” There was no change to the Liquids segment.

This change was a result of our reorganization resulting from Midcoast Energy Partner, L.P.’s, or MEP’s, initial public offering, or IPO, of its Class A common units representing limited partnership interests, which prompted management to reassess the presentation of EEP’s reportable segments considering the financial information available and evaluated regularly by our Chief Operating Decision Maker. Our new segment reporting is consistent with how management makes resource allocation decisions, evaluates performance, and furthers the achievement of our long-term objectives. Financial information for the prior periods has been restated to reflect the change in reporting segments.

Additionally, we have reclassified certain prior period affiliate amounts related to operating revenue, the cost of natural gas, and operating and administrative expenses to conform to the current period presentation. These reclassifications did not impact net income.

After filing our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014, we determined that the beneficial conversion feature of our preferred units in the amount of $47.7 million was incorrectly presented in the statement of financial position as of March 31, 2014, and in the significant changes in partners’ capital table in footnote 7, “Partners’ Capital,” for the three month period ended March 31, 2014. The presentation error resulted in an understatement of the Series 1 Preferred Interests and an overstatement of the General and Limited Partner Interests by $47.7 million at March 31, 2014. We have concluded that this error is immaterial to the prior interim financial statements for the quarterly prior ended March 31, 2014. This error did not affect our total partners’ capital at March 31, 2014, or our cash flow or earnings for the three month period ended March 31, 2014. We have corrected these items for the three and six month periods ended June 30, 2014.

2. NET INCOME PER LIMITED PARTNER UNIT

We allocate our net income among our Series 1 Preferred Units, or Preferred Units, our General Partner, and our limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income attributable to our general and limited partner interests to our General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We also allocate any earnings in excess of distributions to our General Partner and limited partners utilizing the distribution formula for available cash specified in our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and limited partners based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement. Historically we have made the distributions in excess of earnings as follows:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.295	2 %	98 %
First Target Distribution	> $0.295 to $0.35	15 %	85 %
Second Target Distribution	> $0.35 to $0.495	25 %	75 %
Over Second Target Distribution	In excess of $0.495	50 %	50 %

Equity Restructuring Transaction

Effective July 1, 2014, the General Partner entered into an equity restructuring transaction, or Equity Restructuring, with us in which the General Partner irrevocably waived its right to receive cash distributions and allocations of items of income, gain, deduction and loss in excess of 2% in respect of its general partner interest in the incentive distribution rights, or Previous IDRs, in exchange for the issuance to a wholly-owned subsidiary of the General Partner of (i) 66.1 million units of a new class of Partnership units designated as Class D Units, and (ii) 1,000 units of a new class of Partnership units designated as Incentive Distribution Units. The irrevocable waiver is effective with respect to the calendar quarter ending on June 30, 2014, and each calendar quarter thereafter.

The Class D Units entitle the holder thereof to receive quarterly distributions equal to the distribution paid on our common units. The Class D Units are convertible on a one-for-one basis into our Class A common units any time after the fifth anniversary of issuance, or July 1, 2019, at the holder's option. We may redeem Class D Units in whole or in part after the 30-year anniversary of issuance, or July 1, 2044, at our option for either a cash amount equal to the notional value per unit or newly issued Class A common units with an aggregate market value at redemption equal to 105% of the aggregate notional value of the Class D Units being redeemed. The Class D Units have a notional value of $31.35 per unit, which was the closing price of our Class A common units on June 17, 2014, and have the same voting rights as the Class A units. In the event of a liquidation event (or any merger or other extraordinary transaction), the Class D Units will entitle the holder thereof to a preference in liquidation equal to 20% of the notional value, with such preference being increased by an additional 20% on each anniversary of issuance, resulting in a liquidation preference equal to 100% of the notional value on and after July 1, 2018.

The Incentive Distribution Units entitle the holder thereof to receive 23% of the incremental distributions we pay in excess of $0.5435 per common unit and Class D Unit per quarter. In the event of any decrease in the Class A common unit distribution below the current quarterly distribution level of $0.5435 per unit in any quarter during the five years commencing with the fourth quarter of 2014, the distribution we pay on the Class D Units will be adjusted to the amount that we would have paid in respect of the Previous IDRs had the Equity Restructuring not occurred. In addition, the third quarter 2014 distribution on the Class D Units will be reduced so that the aggregate distributions we pay in calendar year 2014 with respect to the Previous IDRs, the Class D Units and the Incentive Distribution Units will not exceed the distribution that we would have paid in calendar year 2014 in respect to the Previous IDRs had the Equity Restructuring not occurred.

We determined basic and diluted net income per limited partner unit as follows:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions, except per unit amounts)			
Net income	$ 112.5	$ 123.7	$ 268.2	$ 56.0
Less Net income attributable to:				
Noncontrolling interest	(42.4)	(18.4)	(78.7)	(34.0)
Series 1 preferred unit distributions	(22.5)	(13.1)	(45.0)	(13.1)
Accretion of discount on Series 1 preferred units	(3.7)	(2.3)	(7.3)	(2.3)
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	43.9	89.9	137.2	6.6
Less distributions:				
Incentive distributions to our General Partner	(38.0)	(32.0)	(71.2)	(63.9)
Distributed earnings allocated to our General Partner	(4.5)	(3.5)	(8.1)	(7.0)
Total distributed earnings to our General Partner	(42.5)	(35.5)	(79.3)	(70.9)
Total distributed earnings to our limited partners	(182.2)	(171.3)	(359.9)	(342.1)
Total distributed earnings	(224.7)	(206.8)	(439.2)	(413.0)
Overdistributed earnings	$(180.8)	$(116.9)	$(302.0)	$(406.4)
Weighted average limited partner units outstanding	327.6	314.8	327.0	311.0
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit (1)	$ 0.56	$ 0.54	$ 1.10	$ 1.10
Overdistributed earnings per limited partner unit (2)	(0.54)	(0.36)	(0.91)	(1.28)
Net income (loss) per limited partner unit (basic and diluted) (3)	$ 0.02	$ 0.18	$ 0.19	$ (0.18)

(1) Represents the total distributed earnings to limited partners divided by the weighted average number of limited partner interests outstanding for the period.

(2) Represents the limited partners' share (98%) of distributions in excess of earnings divided by the weighted average number of limited partner interests outstanding for the period and overdistributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

(3) For the three and six month periods ended June 30, 2014, 43,201,310 anti-dilutive Preferred Units were excluded from the if-converted method of calculating diluted earnings per unit.

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $16.1 million at June 30, 2014, and $24.0 million at December 31, 2013, are included in “Accounts payable and other” on our consolidated statements of financial position.

4. INVENTORY

Our inventory is comprised of the following:

	June 30, 2014	December 31, 2013
	(in millions)	
Materials and supplies	$ 2.1	$ 2.1
Crude oil inventory	24.4	18.0
Natural gas and NGL inventory	138.4	74.8
	$164.9	$94.9

The "Cost of natural gas and natural gas liquids" on our consolidated statements of income includes charges totaling $1.5 million and $3.3 million, and $1.7 million and $2.5 million for the three and six month periods ended June 30, 2014 and 2013, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and natural gas liquids, or NGLs, to reflect the current market value.

5. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment is comprised of the following:

	June 30, 2014	December 31, 2013
	(in millions)	
Land	$ 45.4	$ 43.6
Rights-of-way	770.9	666.2
Pipelines	9,302.2	8,035.8
Pumping equipment, buildings and tanks	2,702.7	2,233.0
Compressors, meters and other operating equipment	2,045.3	1,989.8
Vehicles, office furniture and equipment	353.2	322.0
Processing and treating plants	513.8	514.4
Construction in progress	1,379.0	2,077.7
Total property, plant and equipment	17,112.5	15,882.5
Accumulated depreciation	(2,905.4)	(2,705.7)
Property, plant and equipment, net	$14,207.1	$13,176.8

In the first quarter of 2014, we recorded asset retirement obligations, or AROs, of $100.6 million. Of that amount, $60.0 million is related to Line 6B and is recorded in "Accounts payable and other" with an offset to "Property, plant and equipment, net" in our statement of financial position and $40.6 million is related to Line 3, and is recorded in "Other long-term liabilities" with an offset to "Property, plant and equipment, net" in our consolidated statements of financial position. Both of these pipelines are part of our Lakehead system and the AROs are related to the decommissioning of these pipelines as we are completing Line 6B replacement work in 2014 and have recently announced the Line 3 replacement with an estimated in-service date of late 2017. The associated ARO is a component of the pipelines category of property, plant and equipment, net. We record ARO at fair value in the period in which they can be reasonably determined. Fair value is determined based on expected future cash flows and estimated retirement periods, as well as discount and inflation rates.

6. DEBT

Credit Facilities

We have a committed senior unsecured revolving credit facility, which we refer to as the Credit Facility, that permits aggregate borrowings of up to, at any one time outstanding, $1.975 billion. The maturity date on the Credit Facility is September 26, 2018.

We also have a credit agreement, which we refer to as the 364-Day Credit Facility, that provided aggregate lending commitments of up to $1.2 billion: (1) on a revolving basis for a 364-day period, extendible annually at the lenders' discretion, and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods.

On July 3, 2014, we amended our 364-Day Credit Facility to extend the revolving credit termination date to July 3, 2015, and to decrease aggregate commitments under the facility by $550.0 million. After these changes, our 364-day Credit Facility now provides to us aggregate lending commitments of $650.0 million.

We refer to our Credit Facility and our 364-Day Credit Facility as the Credit Facilities, which provided an aggregate amount of approximately $3.2 billion of bank credit, as of June 30, 2014, which we use to fund our general activities and working capital needs.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. Our policy is to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at any time. Taking that policy into account, at June 30, 2014, we could borrow approximately $1.9 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$3,175.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	1,065.0
Letters of credit outstanding	160.3
Total amount we could borrow at June 30, 2014	$1,949.7

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the three and six month periods ended June 30, 2014 and 2013, we did not have any LIBOR rate borrowings or base rate borrowings.

As of June 30, 2014, we were in compliance with the terms of all of our financial covenants under the Credit Facilities.

On February 3, 2014, we entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank's sole discretion, we view this arrangement as a liquidity enhancement as it allows us to potentially reduce our reliance on utilizing our committed Credit Facilities for issuance of letters of credit to support our hedging activities.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At June 30, 2014, we had approximately $1.1 billion in principal amount of commercial paper outstanding at a weighted average interest rate of 0.33%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $765.0 million during the six month period ended June 30, 2014, which includes gross borrowings of $4.4 billion and gross repayments of $3.6 billion. At December 31, 2013, we had $300.0 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.37%, excluding the effect of our interest rate hedging activities. Our policy is to limit the amount of commercial paper we can issue by the amounts available under our Credit Facility up to an aggregate principal amount of $1.5 billion.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our Credit Facilities. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

Senior Notes

All of our senior notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our senior notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $200.0 million of senior notes issued by Enbridge Energy, Limited Partnership, or the OLP, which we refer to as the OLP Notes. The borrowings under our senior notes are non-recourse to our General Partner and Enbridge Management. All of our senior notes either pay or accrue interest semi-annually and have varying maturities and terms.

The OLP, our operating subsidiary that owns the Lakehead system, has $200.0 million of senior notes outstanding representing unsecured obligations that are structurally senior to our senior notes. The OLP Notes consist of $100.0 million of 7.000% senior notes due in 2018 and $100.0 million of 7.125% senior notes due in 2028. All of the OLP Notes pay interest semi-annually.

Junior Subordinated Notes

The $400.0 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes, represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make cash distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

MEP Credit Agreement

On November 13, 2013, MEP, Midcoast Operating L.P., or Midcoast Operating, and their material domestic subsidiaries, entered into a senior revolving credit facility, which we refer to as the MEP Credit Agreement, that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million. The original term of the MEP Credit Agreement is three years with an initial maturity date of November 2016, subject to four one-year requests for extensions. At June 30, 2014, MEP had $475.0 million in outstanding borrowings under the MEP Credit Agreement at a weighted average interest rate of 1.9%. Under the MEP Credit Agreement, MEP had net borrowings of approximately $140.0 million during the six month period ended June 30, 2014, which includes gross borrowings of $3.4 billion and gross repayments of $3.3 billion. As of June 30, 2014, MEP was in compliance with the terms of its financial covenants.

Interest Cost

Our interest cost for the three and six month periods ended June 30, 2014 and 2013 is comprised of the following:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Interest expense	$80.2	$79.5	$157.1	$155.9
Interest capitalized	10.2	12.1	24.1	26.4
Interest cost incurred	$90.4	$91.6	$181.2	$182.3
Weighted average interest rate	*6.2%*	*6.1%*	*6.4%*	*6.1%*

Fair Value of Debt Obligations

The table below presents the carrying amounts, net of related unamortized discount, and approximate fair values of our debt obligations. The carrying amounts of our outstanding commercial paper and borrowings under our Credit Facilities and prior credit facilities approximate their fair values at June 30, 2014 and December 31, 2013, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The fair value of our outstanding commercial paper and borrowings under our Credit Facilities are included with our long-term debt obligations below since we have the ability and the intent to refinance the amounts outstanding on a long-term basis. The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding. The fair value of our long-term debt obligations is categorized as Level 2 within the fair value hierarchy.

	June 30, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$1,065.0	$1,065.0	$ 300.0	$ 300.0
MEP Credit Agreement	475.0	475.0	335.0	335.0
5.350% Senior Notes due 2014	200.0	204.8	200.0	210.0
5.875% Senior Notes due 2016	299.9	333.9	299.9	335.0
7.000% Senior Notes due 2018	99.9	120.4	99.9	118.6
6.500% Senior Notes due 2018	399.2	469.5	399.1	464.5
9.875% Senior Notes due 2019	500.0	670.4	500.0	663.9
5.200% Senior Notes due 2020	499.9	565.9	499.9	544.8
4.200% Senior Notes due 2021	599.1	635.8	599.1	599.7
7.125% Senior Notes due 2028	99.8	133.8	99.8	121.9
5.950% Senior Notes due 2033	199.8	241.8	199.8	214.4
6.300% Senior Notes due 2034	99.8	125.4	99.8	110.9
7.500% Senior Notes due 2038	399.1	571.0	399.0	503.4
5.500% Senior Notes due 2040	546.4	611.9	546.4	531.0
8.050% Junior subordinated notes due 2067	399.8	452.8	399.7	446.4
Total	$5,882.7	$6,677.4	$4,977.4	$5,499.5

7. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Energy Management, or Enbridge Management, during the six month period ended June 30, 2014.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders [1]	Retained from General Partner [2]	Distribution of Cash
				(in millions, except per unit amounts)			
April 30, 2014	May 8, 2014	May 15, 2014	$0.5435	$214.5	$35.3	$0.7	$178.5
January 30, 2014	February 7, 2014	February 14, 2014	$0.5435	$213.7	$34.6	$0.7	$178.4

(1) We issued 2,453,682 i-units to Enbridge Management, the sole owner of our i-units, during 2014 in lieu of cash distributions.

(2) We retained an amount equal to 2% of the i-unit distribution from our General Partner to maintain its 2% general partner interest in us.

Changes in Partners' Capital

The following table presents significant changes in partners' capital accounts attributable to our General Partner and limited partners as well as the noncontrolling interest in our consolidated subsidiary, OLP, for the six month periods ended June 30, 2014 and 2013. The noncontrolling interest in the OLP arises from the joint funding arrangements with our General Partner and its affiliate to finance: (1) construction of the United States portion of the Alberta Clipper crude oil pipeline and related facilities, which we refer to as the Alberta Clipper Pipeline; (2) expansion of our Lakehead system to transport crude oil to destinations in the Midwest United States, which we refer to as the Eastern Access Projects; and (3) further expansion of our Lakehead system to transport crude oil between Neche, North Dakota and Superior, Wisconsin, which we refer to as the Mainline Expansion Projects.

	For the six month period ended June 30,	
	2014	2013
	(in millions)	
Series 1 Preferred interests		
Beginning balance	$1,160.7	$ —
Proceeds from issuance of preferred units	—	1,200.0
Net income	45.0	13.1
Accretion of discount on preferred units	7.3	2.3
Distribution payable	(45.0)	(13.1)
Beneficial conversion feature of preferred units	—	(47.7)
Ending balance	$1,168.0	$1,154.6
General and limited partner interests		
Beginning balance	$4,637.7	$4,774.9
Proceeds from issuance of partnership interests, net of costs	—	278.7
Net income	137.2	6.6
Distributions	(356.9)	(353.3)
Beneficial conversion feature of preferred units	—	47.7
Ending balance	$4,418.0	$4,754.6
Accumulated other comprehensive loss		
Beginning balance	$ (76.6)	$ (320.5)
Changes in fair value of derivative financial instruments reclassified to earnings	16.6	16.5
Changes in fair value of derivative financial instruments recognized in other comprehensive income (loss)	(152.4)	175.2
Ending balance	$ (212.4)	$ (128.8)
Noncontrolling interest		
Beginning balance	$1,975.6	$ 793.5
Capital contributions	612.9	149.7
Other comprehensive loss allocated to noncontrolling interest	(0.3)	—
Net income	78.7	34.0
Distributions to noncontrolling interest	(42.5)	(28.7)
Ending balance	$2,624.4	$ 948.5
Total partners' capital at end of period	$7,998.0	$6,728.9

Midcoast Energy Partner, L.P.

On November 13, 2013, MEP, one of our subsidiaries, completed its IPO of 18,500,000 Class A common units representing limited partner interests and subsequently issued an additional 2,775,000 Class A common units pursuant to the underwriter's over allotment option. MEP received proceeds (net of underwriting discounts, structuring fees and offering expenses) of approximately $354.9 million. MEP used the net proceeds to distribute approximately $304.5 million to us, to pay approximately $3.4 million in revolving credit facility origination and commitment fees and used approximately $47.0 million to redeem 2,775,000 Class A common units from us. At June 30, 2014, we owned 5.9% of outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 61% of the limited partner interests in Midcoast Operating.

On June 18, 2014, we agreed to sell a 12.6% limited partner interest in Midcoast Operating to MEP, for $350.0 million in cash, which brought our total ownership interest in Midcoast Operating to 48.4%. This transaction closed on July 1, 2014 and represents our first disposition of additional interests in Midcoast Operating since MEP's IPO on November 13, 2013. We intend to sell additional interests in our natural gas assets, held through Midcoast Operating, to MEP and use the proceeds from any such sale as a source of funding for us. However, we do not know when, or if, any additional interests will be offered for sale.

Series 1 Preferred Unit Purchase Agreement

On May 7, 2013, we entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our Series 1 Preferred Units, representing limited partner interests in us, for aggregate proceeds of approximately $1.2 billion. The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset every five years. However, these quarterly cash distributions, during the first full eight quarters ending June 30, 2015, will accrue and accumulate, which we refer to as the Payment Deferral. Thus we will accrue, but not pay these amounts until the earlier of the fifth anniversary of the issuance of the Preferred Units or our redemption of the Preferred Units. The quarterly cash distribution for the three month period ended June 30, 2013 was prorated from May 8, 2013. The preferred unit distributions for the six month period ended June 30, 2014 were $45 million, all of which were deferred. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) we use the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies' treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions, including the Payment Deferral.

We issued the Preferred Units at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders' and General Partner's capital and a decrease in Preferred Unitholders' capital to reflect the fair value of the Preferred Units at issuance on our consolidated statement of partners' capital for the six month period ended June 30, 2013. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013, through the first conversion date, which is June 1, 2016, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders' capital. The impact of accretion of the beneficial conversion feature of $3.7 million and $7.3 million is also included in earnings per unit for the three and six month periods ended June 30, 2014, respectively.

We used the proceeds from the Preferred Unit issuance to repay commercial paper, to finance a portion of our capital expansion program relating to our core liquids and natural gas systems and for general partnership purposes.

8. RELATED PARTY TRANSACTIONS

Investment in Midcoast Energy Partners

We have presented losses from MEP attributable to its public unitholders in the amount of $2.1 million and $1.9 million for the three and six month periods ended June 30, 2014, respectively, in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Distribution from MEP

The following table presents distributions paid by MEP to us and their public Class A common unitholders during the six month period ended June 30, 2014, representing the noncontrolling interest in MEP.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total MEP Distribution
			(in millions)	
April 29, 2014	May 15, 2014	$ 7.8	$ 6.6	$14.4
January 29, 2014	February 14, 2014	4.1	3.6	7.7
		$11.9	$10.2	$22.1

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge Inc., or Enbridge, which we refer to as the Series AC. In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement, a credit agreement between our General Partner and us to finance the Alberta Clipper Pipeline, by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400.0 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Pipeline that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement for any additional costs associated with our construction of the Alberta Clipper Pipeline that we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. Pursuant to the terms of the A1 Term Note, we are required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Pipeline, with the unpaid balance due in 2020. We incurred interest expense under the A1 Term Note of $6.0 million and $12.2 million for the three and six month periods ended June 30, 2014, respectively. We have presented the amounts in “Interest expense, net” on our consolidated statements of income. The approved terms for the Alberta Clipper Pipeline are described in the “Alberta Clipper United States Term Sheet,” which is included as Exhibit I to the June 27, 2008 Offer of Settlement filed with the Federal Energy Regulatory Commission, or FERC, by the OLP and approved on August 28, 2008 (Docket No. OR08-12-000).

A summary of the cash activity for the A1 Term Note for the six month periods ended June 30, 2014 and 2013 are as follows:

	A1 Term Note June 30,	
	2014	2013
	(in millions)	
Beginning Balance	$318.0	$330.0
Borrowings	—	—
Repayments	(6.0)	(6.0)
Ending Balance	$312.0	$324.0

For the three and six month periods ended June 30, 2014, respectively, we allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $11.6 million and $21.7 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline. We also allocated $13.3 million and $26.2 million of such earnings to our General Partner for the three and six month periods ended June 30, 2013, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Distribution to Series AC Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the six month period ended June 30, 2014, representing the noncontrolling interest in the Series AC, and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount paid to the noncontrolling interest	Total Series AC Distribution
			(in millions)	
April 30, 2014	May 15, 2014	$ 6.6	$13.1	$19.7
January 30, 2014	February 14, 2014	6.4	12.8	19.2
		$13.0	$25.9	$38.9

Joint Funding Arrangement for Eastern Access Projects

In May 2012, the OLP amended and restated its limited partnership agreement to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% of all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points at cost. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

Our General Partner has made equity contributions totaling $360.8 million to the OLP during the six month period ended June 30, 2014 to fund its equity portion of the construction costs associated with the Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $27.2 million and $48.8 million to our General Partner for its ownership of the EA interest for the three and six month periods ended June 30, 2014, respectively. We allocated earnings derived from the Eastern Access Projects in the amount of $5.1 million and $7.8 million to our General Partner for the three and six month periods ended June 30, 2013, respectively. We have presented the amount allocated to our General Partner in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Distribution to Series EA Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the six month period ended June 30, 2014, representing the noncontrolling interest in the Series EA, and to us, as the holders of the Series EA general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series EA interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series EA Distribution
			(in millions)	
April 29, 2014	May 15, 2014	$2.5	$6.5	$9.0

Joint Funding Arrangement for U.S. Mainline Expansion Projects

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and us at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the project from 40% to 25%. Within one year of the last project in-service date, scheduled for early 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points at cost. We received $12.0 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013, pursuant to the Mainline Expansion Projects.

Our General Partner has made equity contributions totaling $177.7 million and $59.5 million to the OLP for the six month periods ended June 30, 2014 and 2013, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

We allocated earnings from the Mainline Expansion Projects in the amount of $5.7 million and $10.1 million to our General Partner for its ownership of the ME interest for the three and six month periods ended June 30, 2014, respectively. We have presented the amount we allocated to our General Partner in “Net income attributable to noncontrolling interest” on our consolidated statements of income.

Related Party Transactions with Joint Ventures

We have a 35% aggregate indirect interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together include a 580-mile NGL intrastate transportation pipeline and a related NGL gathering system that was placed into service in the fourth quarter of 2013. Our equity investment in the Texas Express NGL system at June 30, 2014 and December 31, 2013, was $381.6 million and $371.3 million, respectively, which is included on our consolidated statements of financial position in “Other assets, net.” For the three and six month periods ending June 30, 2014, we recognized $2.3 million and $1.0 million of equity earnings, respectively, in “Other income (expense)” on our consolidated statements of income related to our investment in the system.

For the three and six month periods ended June 30, 2014, we incurred $6.1 million and $11.4 million, respectively, of pipeline transportation and demand fees from Texas Express NGL system for our Natural Gas business. We did not incur any fees from the Texas Express NGL system for the three and six month periods ended. June 30, 2013. These expenses are recorded in “Cost of natural gas—affiliate” on our consolidated statements of income.

Our Natural Gas business has made commitments to transport up to 120,000 barrels per day, or bpd, of NGLs on the Texas Express NGL system from 2014 to 2023.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, which we refer to as the Receivables Agreement, with an indirect wholly-owned subsidiary of Enbridge which was amended on September 20, 2013, and again on December 2, 2013. The Receivables Agreement and the transactions contemplated thereby were approved by the special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivable and accrued receivables, or the receivables, of the respective subsidiaries initially up to a monthly maximum of $450.0 million. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "Operating and administrative-affiliate" expense in our consolidated statements of income. For the three and six month periods ended June 30, 2014, the cost stemming from the discount on the receivables sold was not material. For the three and six month periods ended June 30, 2014, we sold and derecognized $1,236.0 million and $2,532.7 million of receivables to the Enbridge subsidiary, respectively. For the three and six month periods ended June 30, 2014, the cash proceeds were $1,235.7 million and $2,532.1 million, respectively, which was remitted to the Partnership through our centralized treasury system. As of June 30, 2014, $408.1 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of June 30, 2014 and December 31, 2013, we have $33.3 million and $69.4 million, respectively, included in "Restricted cash" on our consolidated statements of financial position, consisting of cash collections related to the Receivables sold that have yet to be remitted to the Enbridge subsidiary as of June 30, 2014.

Affiliate Revenue and Purchases

We record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates. Included in our results for the three and six month periods ended June 30, 2014 are operating revenues of $86.0 million and $161.1 million, respectively, and $68.8 million and $139.4 million for the three and six month periods ended June 30, 2013, respectively, related to these transactions.

The purchases of natural gas, NGLs and crude oil from Enbridge and its affiliates are presented in "Cost of natural gas and natural gas liquids—affiliate" on our consolidated statements of income. Included in our results for the three month periods ended June 30, 2014 and 2013 and the six month periods ended June 30, 2014 and 2013 are costs for natural gas, NGLs and crude oil purchases from Enbridge and its affiliates of $38.4 million, $34.5 million, $68.6 million and $72.5 million, respectively.

9. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities through insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our Liquids and Natural Gas businesses. Our General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations.

As of June 30, 2014 and December 31, 2013, we had $47.8 million and $25.8 million, respectively, included in "Other long-term liabilities," that we have accrued for costs we have recognized primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Griffith Terminal Crude Oil Release

On February 25, 2014, a release of approximately 975 barrels of crude oil occurred within the Griffith Terminal in Griffith, Indiana. A repair plan has been reviewed with Pipeline and Hazardous Materials Safety Administration, or PHMSA and repair work has commenced. The released oil was fully contained within our facility and substantially all of the free product was recovered. The released oil did not affect the local community, wildlife or water supply. During the three month period ended June 30, 2014, we increased our total cost estimate by $2.6 million to $7.0 million, primarily due to additional cleanup costs, excluding possible fines and penalties. As of June 30, 2014, we made payments of $2.9 million and we have a remaining estimated liability of $4.1 million.

Lakehead Line 6B Crude Oil Release

We continue to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives we are undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On March 14, 2013, we received an order from the Environmental Protection Agency, or EPA, which we refer to as the Order, that defined the scope which requires additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. We submitted our initial proposed work plan required by the EPA on April 4, 2013, and we resubmitted the workplan on April 23, 2013, and again on May 1, 2013, based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment workplan, or SORA, with modifications on May 8, 2013. We incorporated the modification and submitted an approved SORA on May 13, 2013. At this time we have completed substantially all of the SORA, with the exception of required dredging in and around Morrow Lake and its delta.

We are also working with the Michigan Department of Environmental Quality, MDEQ, to transition submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities from the EPA to the MDEQ, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan or, the Plan.

As of June 30, 2014, our total cost estimate for the Line 6B crude oil release is $1,157.0 million, which is an increase of $35.0 million as compared to December 31, 2013. On May 28, 2014 the MDEQ, Water Resource Division, approved our Schedule of Work for the remainder of 2014. The total cost increase during the three month period ended June 30, 2014, is primarily related to the finalization of the MDEQ approved Schedule of Work and other costs related to the on-going river restoration activities near Ceresco.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at June 30, 2014. Our estimates exclude: (1) amounts we have capitalized, (2) any claims associated with the release that may later become evident, (3) amounts recoverable under insurance, and (4) fines and penalties from other governmental agencies except as described in the Line 6A & 6B Fines and Penalties section below. Our assumptions include, where applicable, estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As we receive invoices for the actual personnel, equipment and services, our estimates will continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations.

These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We continue to have the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

The material components underlying our total estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release include the following:

	(in millions)
Response Personnel & Equipment	$ 539.8
Environmental Consultants	212.0
Professional, regulatory and other	405.2
Total	$1,157.0

For the six month periods ended June 30, 2014 and 2013, we made payments of $65.0 million and $23.6 million, respectively, for costs associated with the Line 6B crude oil release. As of June 30, 2014 and December 31, 2013, we had a remaining estimated liability of $224.5 million and $258.9 million, respectively.

Lines 6A & 6B Fines and Penalties

On September 9, 2010, a crude oil release occurred on Line 6A in Romeoville, Illinois. At June 30, 2014, our total estimated costs for the Line 6A crude oil release does not include an estimate for fines and penalties, which may be imposed by the EPA and PHMSA, in addition to other federal, state and local governmental agencies.

At June 30, 2014, our estimated costs related to the Line 6B crude oil release included in the total $29.6 million in fines and penalties. Due to the absences of sufficient information, we cannot provide a reasonable estimate of our liability for potential additional fines and penalties that could be assessed in connection with each of the releases. As a result, except for the penalties discussed above, we have not recorded any liability for expected fines and penalties. Discussions with governmental agencies regarding fines and penalties are ongoing.

Insurance Recoveries

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates that renew throughout the year. On May 1 of each year, our insurance program is up for renewal and includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry and includes coverage for environmental incidents such as those we have incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties.

A majority of the costs incurred for the crude oil release for Line 6B are covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of $650.0 million for pollution liability. Including our remediation spending through June 30, 2014, we have exceeded the limits of coverage under this insurance policy. As of June 30, 2014, we have recorded total insurance recoveries of $547.0 million for the Line 6B crude oil release, out of the $650.0 million aggregate limit. We expect to record receivables for additional amounts we claim for recovery pursuant to our insurance policies during the period that we deem realization of the claim for recovery to be probable.

In March 2013, we and Enbridge filed a lawsuit against the insurers of our remaining $145.0 million coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line

6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of $42.0 million from the other remaining insurers.

Of the remaining $103.0 million coverage limit, $85.0 million is the subject matter of the lawsuit Enbridge filed in March 2013 against one particular insurer who is disputing our recovery eligibility for costs related to our claim on the Line 6B oil release. The recovery of the remaining $18.0 million is awaiting resolution of this lawsuit. While we believe those costs are eligible for recovery, there can be no assurance that we will prevail in our lawsuit.

We are pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained. Additionally, fines and penalties would not be covered under our existing insurance policy.

Enbridge renewed its comprehensive property and liability insurance programs under which we are insured through April 30, 2015, having a liability aggregate limit of $700.0 million, including sudden and accidental pollution liability. The deductible applicable to oil pollution events will increase to $30.0 million per event, from the current $10.0 million. In the unlikely event that multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement we have entered into with Enbridge, MEP, and other Enbridge subsidiaries.

Legal and Regulatory Proceedings

We are a participant in various legal and regulatory proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We are also directly, or indirectly, subject to challenges by special interest groups to regulatory approvals and permits for certain of our expansion projects.

A number of governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 17 actions or claims are pending against us and our affiliates in state and federal courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, we do not expect the outcome of these actions to be material. On July 2, 2012, PHMSA announced a Notice of Probable Violation, or NOPV, related to the Line 6B crude oil release, including a civil penalty of $3.7 million that we paid during the third quarter of 2012.

Governmental agencies and regulators have also initiated investigations into the Line 6A crude oil release. One claim was filed against us and our affiliates by the State of Illinois in an Illinois state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order. The costs associated with this order are included in the estimated environmental costs accrued for the Line 6A crude oil release. We are also pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

We have accrued a provision for future legal costs and probable losses associated with the Line 6A and Line 6B crude oil releases as described above in this footnote.

10. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility of our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with the risks discussed above through 2018 in accordance with our risk management policies.

Accounting Treatment

Effective January 1, 2014, the Partnership elected to prospectively change its presentation of derivative assets and liabilities from a net basis to a gross basis in the Consolidated Statements of Financial Position. We adopted this change to provide more detailed information about the future economic benefits and obligations associated with our derivative activities in our Consolidated Statements of Financial Position. This change had no impact to the Consolidated Statements of Income, Net income (loss) per limited partner unit, or Partners' capital.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in "Cost of natural gas," "Operating revenue", "Power" or "Interest expense" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to the volatility of our income and cash flows:

Commodity Price Exposures:

- **Transportation**—In our Natural Gas segment, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.
- **Storage**—In our Natural Gas segment, we use derivative financial instruments (i.e., natural gas, crude oil and NGL swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas, crude oil and NGLs and the withdrawal price at which these commodities are sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas, crude oil and NGLs injected and the price received upon withdrawal of these commodities from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection

or withdrawal of these commodities, may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical commodities are recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical commodity is sold from storage. As a result, derivative financial instruments associated with our storage activities can create volatility in our earnings.

- **Condensate, Natural Gas and NGL Options**—In our Natural Gas segment, we use options to hedge the forecasted commodity exposure of our condensate, NGLs and natural gas. Although options can qualify for hedge accounting treatment, pursuant to the authoritative accounting guidance, we have elected non-qualifying treatment. As such, our option premiums are expensed as incurred. These derivatives are being marked-to-market, with the changes in fair value recorded to earnings each period. As a result, our operating income is subject to volatility due to movements in the prices of condensate, NGLs and natural gas until the underlying long-term transactions are settled.

- **Optional Natural Gas Processing Volumes**—In our Natural Gas segment, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

- **NGL and Crude Oil Forward Contracts**—In our Natural Gas segment, we use forward contracts to fix the price of NGLs and crude oil we purchase and to fix the price of NGLs and crude oil that we sell to meet the demands of our customers that sell and purchase NGLs and crude oil. A sub-group of physical NGL and physical crude oil contracts qualify for the normal purchases and normal sales, or NPNS scope exception. All other forward contracts are being marked-to-market each period with the change in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL and crude oil prices until the forward contracts are settled.

- **Natural Gas Forward Contracts**—In our Natural Gas segment, we use forward contracts to sell natural gas to our customers. A sub-group of physical natural gas contracts qualify for the normal purchases and normal sales, or NPNS scope exception. All other forward contracts are being marked-to-market each period with the change in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.

- **Crude Oil Contracts**—In our Liquids segment, we use forward contracts to hedge a portion of the crude oil length inherent in the operation of our pipelines, which we subsequently sell at market rates. These hedges create a fixed sales price for the crude oil that we will receive in the future. We elected not to designate these derivative financial instruments as cash flow hedges, and as a result, will experience some additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.

- **Power Purchase Agreements**—In our Liquids segment, we use forward physical power agreements to fix the price of a portion of the power consumed by our pumping stations in the transportation of crude oil in our owned pipelines. We designate these derivative agreements as non-qualifying hedges because they fail to meet the criteria for cash flow hedging or the NPNS exception. As various states in which our pipelines operate have legislated either partially or fully deregulated power markets, we have the opportunity to create economic hedges on power exposure. As a result, our operating income is subject to additional volatility associated with changes in the fair value of these agreements due to fluctuations in forward power prices.

Except for physical power, in all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. Relating to the power purchase agreements, commodity power purchases are immediately consumed as part of pipeline operations and are subsequently recorded as actual power expenses each period.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	June 30, 2014	December 31, 2013
	(in millions)	
Other current assets	$ 21.7	$ 21.2
Other assets, net	35.2	74.4
Accounts payable and other [(1)]	(274.9)	(172.0)
Other long-term liabilities	(22.5)	(12.3)
Due from general partner and affiliates	0.6	—
Due to general partner and affiliates	(0.1)	—
	$(240.0)	$ (88.7)

(1) Includes $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013, respectively.

The changes in the assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts.

Accumulated Other Comprehensive Income

We record the change in fair value of our derivative financial instruments that qualify for and are designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, in "Accumulated other comprehensive income", also referred to as AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. Upon settlement of the designated cash flow hedges, gains (losses) are reclassified to earnings. Also included in AOCI, as of June 30, 2014, are unrecognized losses of approximately $30.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the six month period ended June 30, 2014, unrealized commodity hedge losses of $0.2 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $255.0 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at June 30, 2014, will be reclassified from AOCI to earnings during the next 12 months.

During the first quarter of 2014 it was determined that a portion of forecasted short term debt transactions were not expected to occur, due to changing funding requirements. Since we will require less short-term debt than previously forecasted, we terminated several of our existing interest rate hedges used to lock-in interest rates on our short-term debt issuances as these hedges no longer meet the cash flow hedging requirements. These terminations resulted in realized losses of $0.8 million for the six month period ended June 30, 2014.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	June 30, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality (1)		
AAA	$ 0.2	$ 0.3
AA	(97.5)	(49.7)
A (2)	(145.9)	(40.1)
Lower than A	3.2	0.8
	$(240.0)	$(88.7)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013, respectively.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also decreased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. We are holding $3.3 million and $16.7 million in cash collateral on our asset exposures at June 30, 2014 and December 31, 2013, respectively. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

In the event that our credit ratings were to decline to the lowest level of investment grade, as determined by Standard & Poor's and Moody's, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our credit ratings had been at the lowest level of investment grade at June 30, 2014, we would have been required to provide additional letters of credit in the amount of $50.3 million.

At June 30, 2014 and December 31, 2013, we had credit concentrations in the following industry sectors, as presented below:

	June 30, 2014	December 31, 2013
	(in millions)	
United States financial institutions and investment banking entities	$(185.6)	$(85.0)
Non-United States financial institutions (1)	(55.7)	0.8
Other	1.3	(4.5)
	$(240.0)	$(88.7)

(1) Includes $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013, respectively.

We are holding $3.3 million and $16.7 million of cash collateral on our asset exposures, and we have provided letters of credit totaling $159.7 million and $76.1 million relating to our liability exposures pursuant to the margin thresholds in effect at June 30, 2014 and December 31, 2013, respectively, under our ISDA® agreements.

Gross derivative balances are presented below before the effects of collateral received or posted and without the effects of master netting arrangements. Both our assets and liabilities are adjusted for non-performance risk, which is statistically derived. This credit valuation adjustment model considers existing derivative asset and liability balances in conjunction with contractual netting and collateral arrangements, current market data such as credit default swap rates and bond spreads and probability of default assumptions to quantify an adjustment to fair value. For credit modeling purposes, collateral received is included in the calculation of our assets, while any collateral posted is excluded from the calculation of the credit adjustment. Our credit exposure for these over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

		Asset Derivatives		Liability Derivatives	
		Fair Value at		Fair Value at	
	Financial Position Location	June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013
		(in millions)			
Derivatives designated as hedging instruments [1]					
Interest rate contracts	Other current assets	$ —	$ 8.1	$ —	$ —
Interest rate contracts	Other assets	22.9	57.1	—	—
Interest rate contracts	Accounts payable and other [2]	—	11.9	(240.9)	(145.5)
Interest rate contracts	Other long-term liabilities	—	—	(9.8)	(11.3)
Commodity contracts	Other current assets	0.9	2.0	—	(0.6)
Commodity contracts	Other assets	0.7	3.5	—	(0.5)
Commodity contracts	Accounts payable and other	—	1.9	(10.0)	(12.7)
Commodity contracts	Other long-term liabilities	—	0.6	(1.5)	(1.4)
		24.5	85.1	(262.2)	(172.0)
Derivatives not designated as hedging instruments					
Commodity contracts	Other current assets	20.8	11.8	—	(0.1)
Commodity contracts	Other assets	11.6	17.6	—	(3.3)
Commodity contracts	Accounts payable and other	—	5.4	(20.7)	(16.3)
Commodity contracts	Other long-term liabilities	—	—	(11.2)	(0.2)
Commodity contracts	Due from general partner and affiliates	0.6	—	—	—
Commodity contracts	Due to general partner and affiliates	—	—	(0.1)	—
		33.0	34.8	(32.0)	(19.9)
Total derivative instruments		$ 57.5	$119.9	$(294.2)	$(191.9)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.

(2) Liability derivatives exclude $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013, respectively.

Effect of Derivative Instruments on the Consolidated Statements of Income and Accumulated Other Comprehensive Income

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]
			(in millions)		
For the three month period ended June 30, 2014					
Interest rate contracts	$ (65.4)	Interest expense	$ (3.4)	Interest expense	$ (5.3)
Commodity contracts	(3.2)	Cost of natural gas	(3.8)	Cost of natural gas	(1.1)
Total	$ (68.6)		$ (7.2)		$ (6.4)
For the three month period ended June 30, 2013					
Interest rate contracts	$ 148.7	Interest expense	$(12.6)	Interest expense	$ 1.1
Commodity contracts	10.0	Cost of natural gas	2.1	Cost of natural gas	1.8
Total	$ 158.7		$(10.5)		$ 2.9
For the six month period ended June 30, 2014					
Interest rate contracts	$(137.1)	Interest expense	$ (8.1)	Interest expense	$(11.0)
Commodity contracts	(3.3)	Cost of natural gas	(10.3)	Cost of natural gas	0.6
Total	$(140.4)		$(18.4)		$(10.4)
For the six month period ended June 30, 2013					
Interest rate contracts	$ 177.6	Interest expense	$(20.1)	Interest expense	$ 0.6
Commodity contracts	8.4	Cost of natural gas	3.6	Cost of natural gas	2.3
Total	$ 186.0		$(16.5)		$ 2.9

(1) Includes only the ineffective portion of derivatives that are designated as hedging instruments and does not include net gains or losses associated with derivatives that do not qualify for hedge accounting treatment.

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges
	(in millions)
Balance at December 31, 2013	$ (76.6)
Other Comprehensive Income before reclassifications [1]	(152.4)
Amounts reclassified from AOCI [2] [3]	16.6
Tax benefit (expense)	—
Net other comprehensive income	$(135.8)
Balance at June 30, 2014	$(212.4)

(1) Excludes NCI loss of $2.1 million reclassified from AOCI at June 30, 2014.
(2) Excludes NCI gain of $1.8 million reclassified from AOCI at June 30, 2014.
(3) For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

Reclassifications from Accumulated Other Comprehensive Income

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Losses (gains) on cash flow hedges:				
Interest Rate Contracts [1]	$3.4	$12.6	$ 8.1	$20.1
Commodity Contracts [2] [3]	3.2	(2.1)	8.5	(3.6)
Total Reclassifications from AOCI	$6.6	$10.5	$16.6	$16.5

(1) Loss (gain) reported within "Interest expense" in the consolidated statements of income.
(2) Loss (gain) reported within "Cost of natural gas" in the consolidated statements of income.
(3) Excludes NCI gain of $0.6 million and $1.8 million reclassified from AOCI for the three and six month periods ending June 30, 2014.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings [1]	For the three month period ended June 30, 2014	For the three month period ended June 30, 2013 [6]	For the six month period ended June 30, 2014	For the six month period ended June 30, 2013 [6]
		Amount of Gain or (Loss) Recognized in Earnings [2]		Amount of Gain or (Loss) Recognized in Earnings [2]	
		(in millions)			
Interest rate contracts	Interest expense [3]	$ —	$ (0.1)	$ —	$ (0.1)
Commodity contracts	Operating revenue [4]	(3.2)	4.2	(4.5)	2.7
Commodity contracts	Operating revenue—Affiliate	0.5	—	0.5	—
Commodity contracts	Power	0.2	(0.1)	0.5	0.2
Commodity contracts	Cost of natural gas [5]	(13.0)	21.6	(19.4)	19.2
Total		$(15.5)	$25.6	$(22.9)	$22.0

(1) Does not include settlements associated with derivative instruments that settle through physical delivery.
(2) Includes only net gains or losses associated with those derivatives that do not qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.
(3) Includes settlement gains of $0.2 million for the six month period ended June 30, 2013.
(4) Includes settlement gains and (losses) of $(0.1) million, $0.9 million, $0.3 million and $1.7 million for the three and six month periods ended June 30, 2014 and June 30, 2013, respectively.
(5) Includes settlement gains and (losses) of $(0.3) million, $1.1 million, $(8.8) million and $0.7 million for the three and six month periods ended June 30, 2014 and June 30, 2013, respectively.
(6) The effects of derivative instruments on consolidated statements of income for the three and six month periods ended June 30, 2013 have been revised to include settlement gains on derivatives not designated as hedge instruments of $2.0 million and $2.6 million, respectively. The revisions to the disclosure had no impact on previously reported net income or earnings per unit.

We record the fair market value of our derivative financial and physical instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a gross basis. However, the terms of the ISDA, which governs our financial contracts and our other master netting agreements, allow the parties to elect in respect of all transactions under the agreement, in the event of a default and upon notice to the defaulting party, for the non-defaulting party to set-off all settlement payments, collateral held and any other obligations (whether or not then due), which the non-defaulting party owes to the defaulting party. The effect of the rights of set-off are outlined below.

Offsetting of Financial Assets and Derivative Assets

	As of June 30, 2014				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$57.5	$—	$57.5	$(26.1)	$31.4
Total	$57.5	$—	$57.5	$(26.1)	$31.4

	As of December 31, 2013				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$119.9	$(24.3)	$95.6	$(18.6)	$77.0
Total	$119.9	$(24.3)	$95.6	$(18.6)	$77.0

Offsetting of Financial Liabilities and Derivative Liabilities

	As of June 30, 2014				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives [(1)]	$(297.5)	$—	$(297.5)	$26.1	$(271.4)
Total	$(297.5)	$—	$(297.5)	$26.1	$(271.4)

	As of December 31, 2013				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives [(1)]	$(208.6)	$24.3	$(184.3)	$18.6	$(165.7)
Total	$(208.6)	$24.3	$(184.3)	$18.6	$(165.7)

(1) Includes $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013 respectively.

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014 and December 31, 2013. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	June 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
Interest rate contracts [(1)]	$—	$(231.1)	$—	$(231.1)	$—	$(96.4)	$—	$(96.4)
Commodity contracts:								
Financial	—	(4.9)	(6.4)	(11.3)	—	6.4	(6.9)	(0.5)
Physical	—	—	4.8	4.8	—	—	(0.2)	(0.2)
Commodity options	—	—	(2.4)	(2.4)	—	—	8.4	8.4
Total	$—	$(236.0)	$(4.0)	$(240.0)	$—	$(90.0)	$ 1.3	$(88.7)

(1) Includes $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013, respectively.

Qualitative Information about Level 2 Fair Value Measurements

We categorize, as Level 2, the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other than quoted prices in active markets for the identical instrument. This category includes both over-the-counter, or OTC, transactions valued using exchange traded pricing information in addition to assets and liabilities that we value using either models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (1) quoted prices for assets and liabilities; (2) time value; and (3) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to value our Level 3 derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (Natural Gas, NGLs, Crude and Power) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in significantly higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the credit valuation adjustment would change the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at June 30, 2014	Valuation Technique	Unobservable Input	Range [(1)] Lowest	Range [(1)] Highest	Range [(1)] Weighted Average	Units
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$(1.1)	Market Approach	Forward Gas Price	3.95	4.91	4.37	MMBtu
NGLs	$(5.3)	Market Approach	Forward NGL Price	0.29	2.20	1.33	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.2	Market Approach	Forward Gas Price	3.50	5.03	4.31	MMBtu
Crude Oil	$(2.5)	Market Approach	Forward Crude Oil Price	91.73	109.03	104.63	Bbl
NGLs	$ 6.3	Market Approach	Forward NGL Price	0.04	2.27	1.19	Gal
Power	$(0.2)	Market Approach	Forward Power Price	35.27	47.32	39.57	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$(2.4)	Option Model	Option Volatility	14%	31%	24%	
Total Fair Value	$(4.0)						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for Natural Gas; dollars per Gallon, or Gal, for NGLs; dollars per barrel, or Bbl, for Crude Oil; and dollars per Megawatt hour, or MWh, for Power.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013 [(2)]	Valuation Technique	Unobservable Input	Range [(1)] Lowest	Range [(1)] Highest	Range [(1)] Weighted Average	Units
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$—	Market Approach	Forward Gas Price	3.64	4.41	4.14	MMBtu
NGLs	$(6.9)	Market Approach	Forward NGL Price	1.00	2.13	1.38	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.1	Market Approach	Forward Gas Price	3.36	4.82	4.15	MMBtu
Crude Oil	$(0.5)	Market Approach	Forward Crude Oil Price	86.37	103.04	97.24	Bbl
NGLs	$(0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Power	$(0.7)	Market Approach	Forward Power Price	32.40	38.98	35.07	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$ 1.3						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for Natural Gas; dollars per Gallon, or Gal, for NGLs; dollars per barrel, or Bbl, for Crude Oil; and dollars per Megawatt hour, or MWh, for Power.

(2) Fair values include credit valuation adjustments of approximately $0.1 million of gains.

Level 3 Fair Value Reconciliation

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2014 to June 30, 2014. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
		(in millions)		
Beginning balance as of January 1, 2014	$ (6.9)	$(0.2)	$ 8.4	$ 1.3
Transfer in (out) of Level 3 [(1)]	—	—	—	—
Gains or losses:				
Included in earnings	(7.3)	4.2	(10.5)	(13.6)
Included in other comprehensive income	(3.3)	—	—	(3.3)
Purchases, issuances, sales and settlements:				
Purchases	—	—	0.4	0.4
Sales	—	—	(0.5)	(0.5)
Settlements [(2)]	11.1	0.8	(0.2)	11.7
Ending balance as June 30, 2014	$ (6.4)	$ 4.8	$ (2.4)	$ (4.0)
Amount of changes in net assets attributable to the change in derivative gains or losses related to assets still held at the reporting date	$ (4.6)	$ 4.1	$(10.3)	$(10.8)
Amounts reported in operating revenue	$ —	$ 3.6	$ —	$ 3.6

(1) Our policy is to recognize transfers as of the last day of the reporting period.

(2) Settlements represent the realized portion of forward contracts.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at June 30, 2014 and December 31, 2013.

	At June 30, 2014						At December 31, 2013	
			Wtd. Average Price [2]		Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	832,732	$ 4.41	$ 4.36	$ 0.1	$—	$—	$ —
	NGL	316,000	$ 62.97	$ 60.27	$ 0.9	$—	$ 0.6	$ (0.4)
Receive fixed/pay variable	Natural Gas	3,631,800	$ 4.32	$ 4.42	$ 0.3	$(0.7)	$ 0.1	$ (1.0)
	NGL	1,612,280	$ 54.87	$ 58.63	$ 1.0	$(7.1)	$ 4.8	$(12.7)
	Crude Oil	725,528	$ 94.78	$103.18	$—	$(6.1)	$ 3.4	$ (5.4)
Receive variable/pay variable	Natural Gas	32,675,300	$ 4.37	$ 4.38	$ 0.7	$(1.1)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	79,594	$ 4.36	$ 4.36	$—	$—	$—	$ —
	NGL	1,355,000	$ 35.27	$ 34.13	$ 1.6	$(0.1)	$ 0.9	$ (0.9)
	Crude Oil	81,000	$105.17	$107.05	$—	$(0.1)	$—	$ —
Receive fixed/pay variable	Natural Gas	333,893	$ 4.41	$ 4.40	$—	$—	$—	$ —
	NGL	2,403,278	$ 37.70	$ 38.51	$ 0.5	$(2.5)	$ 0.4	$ (2.6)
	Crude Oil	184,000	$103.96	$104.85	$ 0.2	$(0.3)	$—	$ (0.4)
Pay fixed	Power [4]	29,510	$ 39.57	$ 46.58	$—	$(0.2)	$—	$ (0.7)
Receive variable/pay variable	Natural Gas	107,169,373	$ 4.41	$ 4.40	$ 1.3	$(0.8)	$ 0.9	$ (0.4)
	NGL	13,859,812	$ 48.43	$ 48.03	$ 6.4	$(0.8)	$ 5.8	$ (3.7)
	Crude Oil	734,242	$101.94	$104.89	$ 0.8	$(2.9)	$ 1.1	$ (1.2)
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	19,080	$ 4.47	$ 4.54	$—	$—	$—	$ —
	NGL	82,500	$ 83.98	$ 84.84	$—	$(0.1)	$—	$ —
	Crude Oil	456,000	$ 96.90	$ 92.94	$ 1.8	$—	$—	$ —
Receive fixed/pay variable	Natural Gas	596,861	$ 4.74	$ 4.51	$ 0.1	$—	$—	$ —
	NGL	755,000	$ 53.11	$ 54.33	$ 0.9	$(1.8)	$ 1.5	$ (1.1)
	Crude Oil	959,665	$ 97.20	$ 97.13	$ 2.4	$(2.4)	$ 8.3	$ —
Receive variable/pay variable	Natural Gas	19,885,000	$ 4.29	$ 4.31	$ 0.3	$(0.7)	$ 0.1	$ —
Physical Contracts								
Receive fixed/pay variable	NGL	295,624	$ 53.31	$ 54.03	$ 0.1	$(0.3)	$—	$ —
Receive variable/pay variable	Natural Gas	79,446,592	$ 4.29	$ 4.29	$ 1.3	$(0.8)	$ 0.5	$ (0.1)
	NGL	2,977,353	$ 66.95	$ 66.50	$ 1.9	$(0.5)	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	—	$ —	$ —	$—	$—	$ 0.7	$ —
Receive variable/pay fixed	Crude Oil	68,250	$ 92.49	$ 90.00	$ 0.2	$—	$—	$ —
Receive variable/pay variable	Natural Gas	5,927,000	$ 4.09	$ 4.11	$—	$(0.1)	$—	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	32,721,379	$ 4.16	$ 4.16	$ 0.7	$(0.6)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	13,399,743	$ 4.38	$ 4.36	$ 0.2	$(0.1)	$—	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl. Our power purchase agreements are measured in MWh.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas, $/Bbl for NGL and crude oil and $/MWh for power.

(3) The fair value is determined based on quoted market prices at June 30, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses and $0.1 million of gains at June 30, 2014 and December 31, 2013, respectively.

(4) For physical power, the receive price shown represents the index price used for valuation purposes.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at June 30, 2014 and December 31, 2013.

	At June 30, 2014						At December 31, 2013	
					Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Strike Price [2]	Market Price [2]	Asset	Liability	Asset	Liability
					(in millions)			
Portion of option contracts maturing in 2014								
Puts (purchased)	Natural Gas	2,208,000	$ 3.90	$ 4.46	$ 0.1	$—	$ 0.7	$—
	NGL	386,400	$54.79	$56.17	$ 1.3	$—	$ 2.9	$—
Calls (written)	NGL	230,000	$60.92	$58.65	$—	$(0.6)	$—	$(1.0)
Puts (written)	Natural Gas	1,472,000	$ 3.90	$ 4.46	$—	$(0.1)	$—	$(0.5)
Calls (purchased)	NGL	46,000	$50.40	$45.50	$ 0.1	$—	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.22	$ 1.0	$—	$ 1.7	$—
	NGL	1,259,250	$49.40	$54.10	$ 4.3	$—	$ 6.0	$—
	Crude Oil	547,500	$85.42	$96.40	$ 1.2	$—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.22	$—	$(0.2)	$—	$(0.3)
	NGL	438,000	$57.05	$54.83	$—	$(2.1)	$—	$(1.0)
	Crude Oil	547,500	$91.75	$96.40	$—	$(4.9)	$—	$(1.9)
Puts (written)	Natural Gas	1,825,000	$ 4.08	$ 4.22	$—	$(0.6)	$—	$—
Calls (purchased)	Natural Gas	1,277,500	$ 5.05	$ 4.22	$ 0.2	$—	$—	$—
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 4.24	$ 0.4	$—	$—	$—
	NGL	366,000	$38.22	$43.67	$ 1.3	$—	$—	$—
	Crude Oil	439,200	$80.00	$91.25	$ 1.5	$—	$—	$—
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 4.24	$—	$(0.3)	$—	$—
	NGL	366,000	$47.02	$43.67	$—	$(1.8)	$—	$—
	Crude Oil	439,200	$92.25	$91.25	$—	$(3.4)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at June 30, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of gains at June 30, 2014.

Fair Value Measurements of Interest Rate Derivatives

We enter into interest rate swaps, caps and derivative financial instruments with similar characteristics to manage the cash flow associated with future interest rate movements on our indebtedness. The following table provides information about our current interest rate derivatives for the specified periods.

				Fair Value [2] at	
Date of Maturity & Contract Type	**Accounting Treatment**	**Notional**	**Average Fixed Rate** [1]	**June 30, 2014**	**December 31, 2013**
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (3.6)	$ (6.8)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (14.4)	$ (13.8)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ 0.2	$ 3.3
Contracts settling prior to maturity					
2014—Pre-issuance Hedges [3]	Cash Flow Hedge	$1,850	4.27%	$(242.3)	$(132.7)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 25.6	$ 60.8

(1) Interest rate derivative contracts are based on the one-month or three-month London Interbank Offered Rate, or LIBOR.

(2) The fair value is determined from quoted market prices at June 30, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $3.4 million of gains at June 30, 2014 and $7.1 million of losses at December 31, 2013.

(3) Includes $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013, respectively.

11. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes, or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws by the State of Texas that apply to entities organized as partnerships. Our income tax expense is based upon many but not all items included in net income.

We computed our income tax expense by applying a Texas state income tax rate to modified gross margin. The Texas state income tax rate was 0.4% for the six month periods ended June 30, 2014 and 2013. Our income tax expense is $2.0 million and $14.2 million, and $4.0 million and $16.0 million for the three and six month periods ended June 30, 2014 and 2013, respectively.

At June 30, 2014 and December 31, 2013, we have included a current income tax payable of $0.7 million and $0.9 million, respectively, in “Property and other taxes payable” on our consolidated statements of financial position. In addition, at June 30, 2014 and December 31, 2013, we have included a deferred income tax payable of $18.7 million and $17.4 million, respectively, in “Deferred income tax liability,” on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

12. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker, collectively comprised of our senior management, in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, because each business segment requires different operating strategies. We have segregated our business activities into two distinct operating segments:

- Liquids; and
- Natural Gas.

During the first quarter of 2014, the Partnership changed its reporting segments. The Marketing segment was combined with the Natural Gas segment to form one new segment called "Natural Gas". There was no change to the Liquids segment.

This change was a result of the reorganization of EEP resulting from MEP's IPO, which prompted Management to reassess the presentation of EEP's reportable segments considering the financial information available and evaluated regularly by EEP's Chief Operating Decision Maker. The new segment is consistent with how management makes resource allocation decisions, evaluates performance, and furthers the achievement of the Partnership's long-term objectives. Financial information for the prior periods has been restated to reflect the change in reporting segments.

The following tables present certain financial information relating to our business segments and corporate activities:

	For the three month period ended June 30, 2014			
	Liquids	Natural Gas	Corporate [1]	Total
	(in millions)			
Operating revenue	$474.3	$1,396.8	$ —	$1,871.1
Cost of natural gas	—	1,259.8	—	1,259.8
Environmental costs, net of recoveries	38.2	—	—	38.2
Operating and administrative	117.6	103.6	3.4	224.6
Power	54.2	—	—	54.2
Depreciation and amortization	76.6	36.8	—	113.4
	286.6	1,400.2	3.4	1,690.2
Operating income (loss)	187.7	(3.4)	(3.4)	180.9
Interest expense, net	—	—	80.2	80.2
Allowance for equity used during construction	—	—	12.6	12.6
Other income (expense) [2]	—	2.3	(1.1)	1.2
Income (loss) before income tax expense	187.7	(1.1)	(72.1)	114.5
Income tax expense	—	—	2.0	2.0
Net income (loss)	187.7	(1.1)	(74.1)	112.5
Less: Net income attributable to:				
Noncontrolling interest	—	—	42.4	42.4
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	3.7	3.7
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$187.7	$ (1.1)	$(142.7)	$ 43.9

(1) Corporate consists of interest expense, interest income, allowance for equity used during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system which we began recognizing operating costs during the fourth quarter of 2013.

	For the three month period ended June 30, 2013			
	Liquids	Natural Gas	Corporate [1]	Total
	(in millions)			
Operating revenue	$366.3	$1,306.4	$ —	$1,672.7
Cost of natural gas	—	1,115.5	—	1,115.5
Environmental costs, net of recoveries	5.2	—	—	5.2
Operating and administrative	98.4	116.4	3.2	218.0
Power	29.2	—	—	29.2
Depreciation and amortization	60.4	35.4	—	95.8
	193.2	1,267.3	3.2	1,463.7
Operating income (loss)	173.1	39.1	(3.2)	209.0
Interest expense, net	—	—	79.5	79.5
Allowance for equity used during construction	—	—	8.1	8.1
Other income	—	—	0.3	0.3
Income (loss) before income tax expense	173.1	39.1	(74.3)	137.9
Income tax expense	—	—	14.2	14.2
Net income (loss)	173.1	39.1	(88.5)	123.7
Less: Net income attributable to:				
Noncontrolling interest	—	—	18.4	18.4
Series 1 preferred unit distributions	—	—	13.1	13.1
Accretion of discount on Series 1 preferred units	—	—	2.3	2.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$173.1	$ 39.1	$(122.3)	$ 89.9

(1) Corporate consists of interest expense, interest income, allowance for equity used during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	As of and for the six month period ended June 30, 2014			
	Liquids	Natural Gas	Corporate [1]	Total
	(in millions)			
Operating revenue	$ 907.0	$3,043.7 [2]	$ —	$ 3,950.7
Cost of natural gas	—	2,748.5	—	2,748.5
Environmental costs, net of recoveries	43.2	—	—	43.2
Operating and administrative	226.0	212.5	3.1	441.6
Power	104.6	—	—	104.6
Depreciation and amortization	143.4	73.8	—	217.2
	517.2	3,034.8	3.1	3,555.1
Operating income (loss)	389.8	8.9	(3.1)	395.6
Interest expense, net	—	—	157.1	157.1
Allowance for equity used during construction	—	—	33.3	33.3
Other income (expense)	—	1.0 [3]	(0.6)	0.4
Income (loss) before income tax expense	389.8	9.9	(127.5)	272.2
Income tax expense	—	—	4.0	4.0
Net income (loss)	389.8	9.9	(131.5)	268.2
Less: Net income attributable to:				
Noncontrolling interest	—	—	78.7	78.7
Series 1 preferred unit distributions	—	—	45.0	45.0
Accretion of discount on Series 1 preferred units	—	—	7.3	7.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 389.8	$ 9.9	$(262.5)	$ 137.2
Total assets	$10,335.9	$5,301.3 [4]	$ 426.2	$16,063.4
Capital expenditures (excluding acquisitions)	$ 985.0	$ 105.0	$ 1.5	$ 1,091.5

(1) Corporate consists of interest expense, interest income, allowance for equity used during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Total segment revenue and intersegment revenue for the natural gas segment for the six-month period ended June 30, 2014 has been corrected to eliminate intra-segment revenue of $318.7 million that was recorded in error and previously reported on our Quarterly Report on Form 10-Q for the three-month period ended March 31, 2014. This error did not impact previously reported segment operating revenue or consolidated operating revenue for the three-month period ended March 31, 2014.

(3) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.

(4) Total assets for our Natural Gas segment includes our long term equity investment in the Texas Express NGL system.

	As of and for the six month period ended June 30, 2013			
	Liquids	Natural Gas	Corporate [1]	Total
	(in millions)			
Operating revenue	$ 699.2	$2,666.5 [2]	$ —	$ 3,365.7
Cost of natural gas	—	2,306.9	—	2,306.9
Environmental costs, net of recoveries	183.7	—	—	183.7
Operating and administrative	185.1	224.2	3.6	412.9
Power	62.8	—	—	62.8
Depreciation and amortization	117.2	70.8	—	188.0
	548.8	2,601.9	3.6	3,154.3
Operating income (loss)	150.4	64.6	(3.6)	211.4
Interest expense, net	—	—	155.9	155.9
Allowance for equity used during construction	—	—	15.9	15.9
Other income	—	—	0.6	0.6
Income (loss) before income tax expense	150.4	64.6	(143.0)	72.0
Income tax expense	—	—	16.0	16.0
Net income (loss)	150.4	64.6	(159.0)	56.0
Less: Net income attributable to:				
Noncontrolling interest	—	—	34.0	34.0
Series 1 preferred unit distributions	—	—	13.1	13.1
Accretion of discount on Series 1 preferred units	—	—	2.3	2.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 150.4	$ 64.6	$(208.4)	$ 6.6
Total assets	$7,811.0	$5,330.4 [3]	$ 159.6	$13,301.0
Capital expenditures (excluding acquisitions)	$ 733.4	$ 125.1	$ 8.6	$ 867.1

(1) Corporate consists of interest expense, interest income, allowance for equity used during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Total segment revenue and intersegment revenue for the natural gas segment for the six-month period ended June 30, 2013 has been corrected to eliminate intra-segment revenue of $248.7 million that was recorded in error for the three-month period ended March 31, 2013. This error did not impact previously reported segment operating revenue or consolidate operating revenue for the three-month period ended March 31, 2013.

(3) Total assets for our Natural Gas segment includes our long term equity investment in the Texas Express NGL system.

13. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative regulatory accounting provisions to a number of our pipeline projects that meet the criteria outlined for regulated operations. The rates for the Southern Access, Alberta Clipper and Eastern Access pipelines as well as for our Line 6B 75-mile Replacement Project and Line 14 Project, which are currently the primary applicable projects, are based on a cost-of-service recovery model that follows the FERC's authoritative guidance and is subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology, we calculate tolls annually based on forecast volumes and costs. A difference between forecast and actual results causes an under or over collection of revenue in any given year, which is trued-up in the following year. Under the authoritative accounting provisions applicable to our regulated operations, over or under collections of revenue are recognized in the financial statements currently and these amounts are realized the following year. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these expansions through the annual cost-of-service filings with the FERC and through toll rate adjustments with our customers. The assets and liabilities that we recognize for regulatory purposes are recorded in "Other current assets" and "Accounts payable and other," respectively, on our consolidated statements of financial position.

Southern Access Pipeline

For the three and six month period ended June 30, 2014, we over collected revenue for our Southern Access Pipeline primarily due to lower than anticipated power cost adjustments and actual volumes being higher than forecasted volumes used for the April 2013 surcharge filing. This was partially offset by increased income tax allowance resulting from higher than anticipated tax rate. As a result, for the three and six month periods ended June 30, 2014, we adjusted our revenues by a net decrease of $0.4 million and $3.8 million, respectively, on our consolidated statements of income with a corresponding increase in the regulatory liability on our consolidated statements of financial position at June 30, 2014. The amounts will be included in our tolls beginning August 2014 when we update our transportation rates.

For 2013, we under collected revenue for our Southern Access Pipeline primarily due to our actual volumes being lower than the forecasted volumes used for our April 2013 surcharge filing, partially offset by higher than anticipated power credit adjustments. As a result, in 2013, we increased revenues on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position. For the three and six month periods ended June 30, 2014, we decreased our revenues by $4.0 million and $5.7 million, respectively, on our consolidated statement of income with a corresponding amount decreasing the regulatory asset on our consolidated statement of financial position at June 30, 2014. At June 30, 2014 and December 31, 2013, we had a $1.3 million and $7.0 million regulatory asset, respectively, on our consolidated statements of financial position related to this under collection. We will recover these amounts from our customers beginning August 2014.

Alberta Clipper Pipeline

For the three and six month periods ended June 30, 2014, we under collected revenue on our Alberta Clipper Pipeline primarily due to higher than anticipated costs, higher than anticipated equity return used for our April 2013 surcharge filing, and higher than anticipated income tax allowance due to a higher tax rate. The higher costs were partially offset by higher than anticipated volumes. As a result, for the three and six month periods ended June 30, 2014, we increased our revenues by $4.8 million and $7.6 million, respectively, on our consolidated statement of income with a corresponding decrease in the regulatory liability on our consolidated statement of financial position at June 30, 2014 for the differences in transportation volumes. The amounts will be included in our tolls beginning August 2014.

For 2013, we under collected revenue on our Alberta Clipper Pipeline primarily due to our actual volumes being lower than forecasted volumes used for our April 2013 surcharge filing and our income tax rate and return on equity rate base being higher than anticipated, partially offset by higher than anticipated power credit adjustments. As a result, in 2013 we increased our revenues for the amounts we under collected and recorded a decrease in our regulatory liability. For the three and six month periods ended June 30, 2014, we decreased our revenues by $5.2 million and $5.7 million, respectively on our consolidated statement of income with a corresponding amount decreasing the regulatory asset on our consolidated statement of financial position at June 30, 2014. At June 30, 2014 and December 31, 2013 we had regulatory assets of $1.8 million and $7.5 million respectively in our consolidated statements of financial position for the difference in volumes. These amounts will be included in our tolls beginning August 2014 when we update our transportation rates to account for the lower delivered volumes.

Eastern Access Projects

For the three and six month periods ended June 30, 2014, we under collected revenue on an expansion component of our Eastern Access Projects due to an increase in the capital rate base as various components of the project were placed into service, as well as higher than anticipated return on equity rate and it increases income tax allowance due to a higher tax rate. As a result, for the three and six month periods ended June 30, 2014, we increased our revenue by $10.7 million and $11.1 million, respectively on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statement of financial position at June 30, 2014. The amounts will be collected in our tolls beginning August 2014 when we update our transportation rates.

For 2013, we over collected revenue on our expansion component of our Eastern Access Projects due to a delay in the in-service date. As a result, in 2013 we reduced our revenues on our consolidated statements of income with a corresponding increase in the regulatory liability on our consolidated statements of financial position at December 31, 2013. For the three and six month periods ended June 30, 2014, we increased our revenues by $3.1 million and $5.7 million, respectively, on our consolidated statement of income with a corresponding amount reducing the regulatory liability on our consolidated statement of financial position. At June 30, 2014 and December 31, 2013 we had a regulatory liability of $4.9 million and $10.6 million, respectively. The amounts will be refunded through our tolls when we update our transportation rates which became effective August 2014.

Lakehead Line 6B 75-Mile Replacement Project

For the three and six month periods ended June 30, 2014, we under collected revenue for our Lakehead Line 6B 75-Mile Replacement Project. As a result, for the three and six month periods ended June 30, 2014, we increased our revenue by $3.8 million and $6.3 million, respectively, on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position at June 30, 2014. The amounts will be recovered beginning August 2014 when we update our transportation rates.

For 2013, we under collected revenue for our Lakehead Line 6B 75-Mile Replacement Project due to the capital rate base being higher than anticipated, as well as higher than anticipated return on equity rate and increases income tax allowance due to a higher tax rate. As a result, for year ended December 31, 2013, we increased our revenue on our consolidated statements of income with a corresponding decrease in the regulatory asset on our consolidated statements of financial position. For the three and six month periods ended June 30, 2014, we decreased our revenues by $1.1 million and $1.9 million, respectively, on our consolidated statement of income with a corresponding amount decreasing the regulatory asset on our consolidated statement of financial position. At June 30, 2014 and December 31, 2013 we had a regulatory asset of $1.4 million and $3.3 million, respectively. The amounts will be recovered beginning August 2014 when we update our transportation rates.

Line 14 Pipeline (Part of Lakehead System)

During the three-month period ended June 30, 2014 Line 14 became eligible for the authoritative regulatory accounting provisions due to an expiration of the System Expansion Project II, or SEPII, agreement on March 31, 2014 and negotiations settled with the Canadian Association of Petroleum Producers, or CAPP, to recover the remaining rate base associated with Line 14. Because of the delay of the normal April 1 annual tariff filing we continued to collect on the rate provisions of the 2013 tariff filing in the second quarter of 2014. The 2013 rates contained provisions that were not applicable under the newly negotiated agreement and thus created an overcollection of revenues on this aspect of the tariff during the three-month period ended June 30, 2014. As a result, we decreased our revenues by $22.5 million with a corresponding increase in our regulatory liabilities.

Other Contractual Obligations

Southern Access Pipeline

We have entered into certain contractual obligations with our customers on the Southern Access Pipeline in which a portion of the revenue earned on volumes above certain predetermined shipment levels, or qualifying volumes, are returned to the shippers through future rate adjustments. We record the liabilities associated with this contractual obligation in “Accounts payable and other,” on our consolidated statements of financial position. The amortization for this contractual obligation reflects the related transportation rate adjustment in the subsequent year. At June 30, 2014 and December 31, 2013, we had $1.7 million and $6.1 million, respectively, in qualifying volume liabilities related to the Southern Access Pipeline on our statements of financial position. For the six month periods ended June 30, 2014 and 2013, we increased our revenues by $4.4 million and $7.5 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position to account for amortization of the liability.

Alberta Clipper Pipeline

A portion of the rates we charge our customers includes an estimate for annual property taxes. If the estimated property tax we collect from our customers is significantly higher than the actual property tax imposed, we are contractually obligated to refund 50% of the property tax over collection to our customers. At June 30, 2014 and December 31, 2013, we had $6.6 million and $6.9 million, respectively, in property tax over collection liabilities related to our Alberta Clipper Pipeline on our statements of financial position.

For 2013, we also incurred liabilities related to this contractual obligation on the Alberta Clipper Pipeline. As a result, in 2013, we reduced revenues for the amounts due back to our shippers and recorded a liability for the contractual obligation. We amortize the liability on a straight line basis in the following year. For the six month periods ended June 30, 2014 and 2013, we increased our revenues by $3.5 million and $1.5 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Allowance for Equity Used During Construction

We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Eastern Access Projects, Line 6B 75-mile Replacement and Mainline Expansion Projects, we recorded $33.3 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at June 30, 2014, and corresponding $33.3 million of "Allowance for equity used during construction" in our consolidated statement of income for the six month period ended June 30, 2014. We recorded $15.9 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at June 30, 2013, and corresponding $15.9 million of "Allowance for equity used during construction" in our consolidated statements of income for the six month period ended June 30, 2013.

FERC Transportation Tariffs

Lakehead System

Effective April 1, 2013, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2013 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. This tariff rate adjustment filing also included the recovery of costs related to the Flanagan Tank Replacement Project and the Eastern Access Phase 1 Mainline Expansion Project. The Lakehead system utilizes the System Expansion Project II and the Facility Surcharge Mechanism, or FSM, which are components of our Lakehead system's overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

This tariff filing increased the transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.28 per barrel, to approximately $2.13 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

On June 27, 2014, we filed for an increase to our Lakehead system rates. These rates have an effective date of August 1, 2014. This tariff filing was in part an index filing in accordance with 18 C.F.R.342.3 and in part a compliance filing with certain settlement agreements, which are not subject to FERC indexing. This filing included the increase in rates in compliance with the indexed rate ceilings allowed by the FERC which incorporates the multiplier of 1.038858, which was issued by the FERC on May 14, 2014, in Docket No. RM93-11-000. This filing also reflected our annual tariff rate adjustment for the FSM components or our Lakehead systems' overall rate structure, as described above. As part of this rate structure our rates reflect our projected costs for 2014 and true-ups for the difference between estimated and actual costs for the prior year. Historically, we have made the Lakehead system annual tariff rate adjustment for the FSM component of rates with an effective date of April 1 and the index rate filing with an effective date of July 1, however, the filings were delayed as we were in negotiations with CAPP concerning certain components of the tariff rate structure. This negotiation eliminates the SEPII surcharge and added to the FSM component of rates recovery of costs for Line 14, which is virtually the entire asset base associated with the SEPII expansion. The recent negotiation also provides for the recovery of Agreed-Upon Legacy Integrity and Agreed-Upon Future Integrity. These elements are a portion of the costs incurred by the Partnership to maintain the integrity and safety of the pipeline systems. The rates also include recovery of costs related to Eastern Access Phase 2 Mainline Expansion and the 2014 Mainline Expansions.

This tariff filing increased the transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.32 per barrel, to approximately $2.49 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

*North Dakota and Ozark System*s

Effective April 1, 2013 for the North Dakota system we filed updates to the calculation of the surcharges on the two previously approve expansion, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. These expansions are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. This filing increased the average transportation rate for crude oil movements on our North Dakota System by $0.55 per barrel, to an average of approximately $2.06 per barrel.

Effective July 1, 2013, we filed FERC tariffs for our North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by FERC which incorporates the multiplier of 1.045923, which was issued by FERC on May 15, 2013, in Docket No. RM93-11-000.

Effective April 1, 2014, we filed updates to the calculation of the surcharges on the two previously approved expansions, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. As previously mentioned these expansions are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing increased transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.09 per barrel, to an average of approximately $2.21 per barrel.

On May 30, 2014, we filed FERC tariffs with effective dates of July 1, 2014 for our North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by the FERC which incorporates the multiplier of 1.038858, which was issued by the FERC on May 14, 2014, in Docket No. RM93-11-000.

14. SUPPLEMENTAL CASH FLOWS INFORMATION

In the "Cash used in investing activities" section of the consolidated statements of cash flows, we exclude changes that did not affect cash. The following is a reconciliation of cash used for additions to property, plant and equipment to total capital expenditures (excluding "Investment in joint venture"):

	For the six month period ended June 30,	
	2014	**2013**
	(in millions)	
Additions to property, plant and equipment	$1,309.0	$859.7
Increase (decrease) in construction payables	(217.5)	7.4
Total capital expenditures (excluding "Investment in joint venture")	$1,091.5	$867.1

15. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In April of 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2014-08 that both changes the criteria and requires expanded disclosures of reporting discontinued operations. The adoption of the pronouncement is not anticipated to have a material impact on our consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

In May of 2014, FASB issued Accounting Standards Update No. 2014-09 that outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes the most current revenue recognition guidance, including industry-specific guidance. The impact of the adoption of the pronouncement on our consolidated financial statements is still being evaluated. This accounting update is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis.

16. SUBSEQUENT EVENTS

364-Day Credit Facility

On July 3, 2014, we amended our 364-Day Credit Facility to extend the revolving credit termination date to July 3, 2015, and to decrease aggregate commitments under the facility by $550.0 million. After these changes, our 364-day Credit Facility now provides to us aggregate lending commitments of $650.0 million.

Equity Restructuring Transaction

Effective July 1, 2014, the General Partner entered into an equity restructuring transaction, or Equity Restructuring, with the Partnership in which the General Partner irrevocably waived its right to receive cash distributions and allocations of items of income, gain, deduction and loss in excess of 2% in respect of its general partner interest in the Previous IDRs, in exchange for the issuance to a wholly-owned subsidiary of the General Partner of (i) 66.1 million units of a new class of Partnership units designated as Class D Units, and (ii) 1,000 units of a new class of Partnership units designated as Incentive Distribution Units. The irrevocable waiver is effective with respect to the calendar quarter ending on June 30, 2014, and each calendar quarter thereafter. See Note 2. *Net Income Per Limited Partner Unit.*

In connection with the Equity Restructuring, effective July 1, 2014, we amended and restated our partnership agreement. The amendments among other changes and in conjunction with the waiver described above, effectively modified the distribution rights provided for by our partnership agreement to waive the Previous IDRs and to provide distribution rights to the new Class D Units and Incentive Distribution Units. These changes are discussed more fully in our Form 8-A/A filed with the SEC on July 1, 2014. Also, as part of the amendment to our partnership agreement, certain amendments were made to increase the Partnership's flexibility to maintain and increase interim distributions to unitholders until current and future growth investments by the Partnership begin to generate cash and to enhance the Partnership's ability to execute its long-term growth plans in a capital efficient and accretive manner.

Midcoast Energy Partners, L.P.

On June 18, 2014, we agreed to sell a 12.6% limited partner interest in Midcoast Operating to MEP, for $350.0 million in cash, which will bring EEP's total ownership interest in Midcoast Operating to 48.4%. This transaction closed on July 1, 2014, and represents EEP's first disposition of additional interests in Midcoast Operating since MEP's initial public offering on November 13, 2013. See Note 7. *Partner's Capital*

Distribution to Partners

On July 31, 2014, the board of directors of Enbridge Management declared a distribution payable to our partners on August 14, 2014. The distribution will be paid to unitholders of record as of August 7, 2014 of our available cash of $224.7 million at June 30, 2014, or $0.5550 per limited partner unit. Of this distribution, $187.3 million will be paid in cash, $36.7 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.8 million will be retained from our General Partner from amounts otherwise distributable to it in respect of its general partner interest and limited partner interest to maintain its 2% general partner interest.

Distribution to Series AC Interests

On July 31, 2014, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series AC interests, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $14.8 million to the noncontrolling interest in the Series AC, while $7.4 million will be paid to us.

Distribution to Series EA Interests

On July 31, 2014, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series EA interests, declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP will pay $16.7 million to the noncontrolling interest in the Series EA, while $5.6 million will be paid to us.

Distribution from MEP

On July 31, 2014, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable to their partners on August 14, 2014. The distribution will be paid to unitholders of record as of August 7, 2014, of MEP's available cash of $15.0 million at June 30, 2014, or $0.3250 per limited partner unit. MEP will pay $6.9 million to their public Class A common unitholders, while $8.1 million in the aggregate will be paid to us with respect to our Class A common units, subordinated units and to Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On July 31, 2014, the general partner of Midcoast Operating, acting in its capacity as the general partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of August 7, 2014. Midcoast Operating will pay $22.0 million to us and $23.5 million to MEP.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Item 1. *Financial Statements* of this report.

In May 2013, we formed Midcoast Energy Partners, L.P., or MEP. On November 13, 2013, MEP completed its initial public offering, or the IPO, of Class A common units, representing limited partner interests in MEP. On the same date, in connection with the closing of the IPO, certain transactions, among others, occurred pursuant to which we effectively conveyed to MEP all of our limited liability company interests in the general partner of the operating subsidiary of MEP, or Midcoast Operating, and a 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units and MEP Subordinated Units, approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the contributed businesses, and a right to receive $323.4 million in cash which was paid to us on November 13, 2013. In addition, in connection with the IPO and the closing of the underwriters' exercise of its over-allotment option, we received $47.0 million from MEP in its redemption of 2,775,000 of MEP Class A common units from us. At June 30, 2014, we owned 5.9% of the outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 61% of the limited partner interests in Midcoast Operating.

On June 18, 2014, we agreed to sell a 12.6% limited partner interest in Midcoast Operating to our affiliate MEP, for $350.0 million in cash, which brought our total ownership interest in Midcoast Operating to 48.4%. This transaction closed on July 1, 2014, and represents our first disposition of additional interests in Midcoast Operating the IPO. We do not know when, or if, any additional interests will be offered for sale.

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through two business segments: Liquids and Natural Gas. During the first quarter of 2014, the Partnership changed its reporting segments. The Marketing segment was combined with the Natural Gas segment to form one new segment named "Natural Gas". There was no change to the Liquids segment.

This change was a result of the reorganization of EEP resulting from the IPO which prompted management to reassess the presentation of EEP's reportable segments considering the financial information available and evaluated regularly by EEP's Chief Operating Decision Maker. The new segment is consistent with how management makes resource allocation decisions, evaluates performance, and furthers the achievement of the Partnership's long-term objectives. Financial information for the prior periods has been restated to reflect the change in reporting segments.

The following table reflects our operating income by business segment and corporate charges for each of the three and six month periods ended June 30, 2014 and 2013.

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Operating income (loss)				
Liquids	$187.7	$173.1	$389.8	$150.4
Natural Gas	(3.4)	39.1	8.9	64.6
Corporate, operating and administrative	(3.4)	(3.2)	(3.1)	(3.6)
Total operating income	180.9	209.0	395.6	211.4
Interest expense	80.2	79.5	157.1	155.9
Allowance for equity used during construction	12.6	8.1	33.3	15.9
Other income	1.2	0.3	0.4	0.6
Income before income tax expense	114.5	137.9	272.2	72.0
Income tax expense	2.0	14.2	4.0	16.0
Net income	112.5	123.7	268.2	56.0
Less: Net income attributable to:				
Noncontrolling interest	42.4	18.4	78.7	34.0
Series 1 preferred unit distributions	22.5	13.1	45.0	13.1
Accretion of discount on Series 1 preferred units	3.7	2.3	7.3	2.3
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 43.9	$ 89.9	$137.2	$ 6.6

Contractual arrangements in our Liquids and Natural Gas segments expose us to market risks associated with changes in commodity prices where we receive crude oil, natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices. These fluctuations can be significant if commodity prices experience significant volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in crude oil, natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Liquids

The following factors primarily affected the $14.6 million and the $239.4 million increases in operating income for the three and six month periods ended June 30, 2014, respectively, when compared to the same period of 2013:

- Increased revenue of $61.7 million and $124.5 million for the three and six month periods ended June 30, 2014, respectively, related to rate increases as a result of tariff filings that became effective July 1, 2013 and April 1, 2014. Operating revenue on our Lakehead system was offset by $19.1 million and $28.6 million for the three and six month periods ended June 30, 2014, respectively, related to regulatory true-ups on Lakehead toll revenues;
- Decreased environmental expense of $140.5 million for the six month period ended June 30, 2014 as compared with the same period in 2013, primarily due lower environmental accruals, net of recoveries, related to the Line 6B crude oil release recognized in the second quarter of 2013;

- Increased volumes on our North Dakota and Lakehead systems increased revenue by $52.3 million and $79.9 million for the three and six month periods ended June 30, 2014, respectively, when compared to the same periods in 2013;
- Increased rail revenue of $4.3 million and $12.9 million for the three and six month periods ended June 30, 2014, respectively, on our Berthold Rail system which was placed in service in March of 2013; and
- Increased revenue from our ship or pay agreements of $12.6 million on our North Dakota Bakken system for the six month period ended June 30, 2014.

The increase in operating income was offset by the following factors:

- Increased operating and administrative expenses of $19.2 million and $40.9 million for the three and six month periods ended June 30, 2014, respectively, when compared to the same period in 2013. This is due to increases of $1.5 million and $8.7 million in operational costs for the three and six month periods ended June 30, 2014, respectively, as well as higher workforce related costs, property taxes, and increased administrative, regulatory and compliance support necessary for both the three and six months periods ended June 30, 2014:
- Increased power costs of $25.0 million and $41.8 million for the three and six month periods ended June 30, 2014, respectively, as compared to the same periods in 2013 related to increased volumes; and
- Increased depreciation expense of $16.2 million and $26.2 million for the three and six month periods ended June 30, 2014, respectively, when compared to the same periods in 2013, directly attributable to additional assets placed into service.

Natural Gas

The operating income of our Natural Gas business decreased $42.5 million and $55.7 million for the three and six month periods ended June 30, 2014, respectively, when compared to the same periods in 2013, primarily due to the following:

- Decreased operating income of approximately $17.4 million and $35.3 million for the three and six month periods ended June 30, 2014, respectively, when compared to the same periods in 2013, due to reduced average daily volumes on our major systems primarily attributable to reduced and delayed drilling activity in the Anadarko and East Texas regions;
- Decreased operating income of $33.1 million and $27.0 million for the three and six month periods ended June 30, 2014, respectively, when compared to the same periods in 2013, due to non-cash, mark-to-market net losses from derivative instruments that do not qualify for hedge accounting treatment;
- Decreased operating revenue less the cost of natural gas derived from keep-whole processing earnings for the three and six month periods ended June 30, 2014, of $4.9 million and $12.4 million, respectively, when compared to the same periods in 2013, due to a decline in total NGL production primarily caused by the Avinger plant shutdown from early January until mid-February of 2014;
- Decreased operating income of approximately $3.0 million for the six month period ended June 30, 2014, when compared to the same period in 2013, primarily due to the impact of sustained freezing temperatures which significantly disrupted producer well head production levels and our pipeline operations;
- Decreased operating income of $1.3 million and $2.2 million for the three and six month periods ended June 30, 2014, respectively, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same periods in 2013; and
- Increased depreciation and amortization expense of $1.4 million and $3.0 million for the three and six month periods ended June 30, 2014, respectively, as compared with the same periods in 2013, due to additional assets that were put in service.

The above factors were partially offset for the three and six month periods ended June 30, 2014, as compared with the same periods in 2013 primarily due to:

- Increased operating revenues of $4.4 million for the three and six month periods ended June 30, 2014, related to contractual minimum volume commitment contracts in which our customer has not moved the required volumes; and
- Increased operating income of $1.3 million and $12.7 million due to improvement in natural gas and NGL prices for the three and six month periods ended June 30, 2014, respectively, when compared to the same periods in 2013.

Derivative Transactions and Hedging Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and interest rates and to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices or interest rates. We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as follows:

- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- Natural Gas segment commodity-based derivatives—"Operating revenue" and "Cost of natural gas"
- Corporate interest rate derivatives—"Interest expense"

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net changes in fair value associated with our derivative financial instruments:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Liquids segment				
Non-qualified hedges	$ (5.3)	$ 3.2	$ (7.5)	$ 1.2
Natural Gas segment				
Hedge ineffectiveness	(1.1)	1.8	0.6	2.3
Non-qualified hedges	(9.7)	20.5	(6.8)	18.5
Commodity derivative fair value net gains (losses)	(16.1)	25.5	(13.7)	22.0
Corporate				
Hedge ineffectiveness	(5.3)	1.1	(11.0)	0.6
Non-qualified interest rate hedges	—	(0.1)	—	(0.3)
Derivative fair value net gains (losses)	$(21.4)	$26.5	$(24.7)	$22.3

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

The following tables set forth the operating results and statistics of our Liquids segment assets for the periods presented:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Operating Results:				
Operating revenue	$474.3	$366.3	$907.0	$699.2
Environmental costs, net of recoveries	38.2	5.2	43.2	183.7
Operating and administrative	117.6	98.4	226.0	185.1
Power	54.2	29.2	104.6	62.8
Depreciation and amortization	76.6	60.4	143.4	117.2
Operating expenses	286.6	193.2	517.2	548.8
Operating income	$187.7	$173.1	$389.8	$150.4
Operating Statistics				
Lakehead system:				
United States [(1)]	1,631	1,281	1,596	1,375
Province of Ontario [(1)]	457	402	449	384
Total Lakehead system deliveries [(1)]	2,088	1,683	2,045	1,759
Barrel miles (billions)	144	113	279	233
Average haul (miles)	759	739	753	732
Mid-Continent system deliveries [(1)]	176	170	194	196
North Dakota system:				
Trunkline [(1)]	311	148	277	136
Gathering [(1)]	3	3	3	3
Total North Dakota system deliveries [(1)]	314	151	280	139
Total Liquids Segment Delivery Volumes [(1)]	2,578	2,004	2,519	2,094

(1) Average barrels per day in thousands.

Three month period ended June 30, 2014 compared with the three month period ended June 30, 2013

The operating revenue of our Liquids segment increased $108.0 million for the three month period ended June 30, 2014 when compared with the same period in 2013, primarily due to (1) increased tariff rates that became effective July 1, 2013 with Federal Energy Regulatory Commission, or FERC, for our Lakehead, North Dakota and Ozark systems, and (2) an increase in volumes on our systems. The increase in tariff rates accounted for $61.7 million of the increase in operating revenue for the three month period ended June 30, 2014 when compared to June 30, 2013.

The increase in tariff rates period-over-period was offset by a $19.1 million decrease in revenues period-over-period as a result of regulatory true-ups related to Lakehead toll revenues. This decrease was due in large part to an over-collection of revenues on the System Expansion Project II, or SEPII, surcharge due to 2013 rates containing provisions that were not applicable under the newly negotiated agreement for Line 14. Generally, these rates would have been updated on April 1 as part of the annual tariff filing. However, due to the renegotiation and the expected delay in the annual filing for the Lakehead system, we over-collected our revenues on SEPII.

The Lakehead tariff that will be effective on August 1, 2014 eliminates the SEPII surcharge as mentioned above and adds to the FSM component of rates recovery of costs for Line 14, Agreed-Upon Legacy Integrity and Agreed-Upon Future Integrity. The FSM revenue requirement for 2014 will be recovered over a 5 month period from August to December versus the usual 9 month period from April to December as done in the typical Lakehead FSM filing schedule. This shortened recovery caused the rates to increase by approximately 4.6% over what they would have been effective April 1.

Operating revenue of our Liquids business increased for the three month period ended June 30, 2014 when compared with the same period in 2013 by $19.7 million due to higher average daily delivery volumes on our Lakehead, Mid-Continent, and North Dakota systems. Average daily volumes delivered increased 574,000 barrels per day during the three month period ended June 30, 2014 compared to the three month period ended June 30, 2013. Our Lakehead system realized higher daily volumes of approximately 405,000 barrels per day, which contributed to increased revenue of $32.6 million.

Additionally, our operating revenue increased for the three month period ended June 30, 2014, when compared to the same period in 2013, due to an increase of $4.3 million from our Berthold Rail and Bakken Systems. The increase is the result of higher average daily delivered volumes when compared to the same period last year.

Environmental costs, net of recoveries, increased $33.0 million for the three month period ended June 30, 2014 when compared with the same period in 2013. On March 14, 2013, we received an order from the EPA, or the Environmental Protection Agency, which we refer to as the Order, which required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. During the three month period ended June 30, 2014, we had $35 million in cost accruals related to the remediation of the Line 6B crude oil release and no insurance recoveries resulting in $35 million of environmental cost, net of recoveries. During the three month period ended June 30, 2013 we had $40 million of cost accruals related to the Line 6B crude oil release during the period, which were offset by $42 million in insurance recoveries compared to no insurance recoveries for the comparable period this year.

The operating and administrative expenses of our Liquids business increased $19.2 million for the three month period ended June 30, 2014 when compared with the same period in 2013 primarily due to the increased costs of $14.4 million related to workforce expenses. This increase was primarily due to additional costs associated with regulatory and compliance support necessary for our systems. Additionally, operating and administrative expenses increased as a result of increased property taxes of $2.8 million and higher costs related to our integrity program of $6.7 million.

Power costs increased $25.0 million for the three month period ended June 30, 2014 when compared to the same period in 2013 primarily as a result of increased volumes.

The increase in depreciation expense of $16.2 million for the three month period ended June 30, 2014 is directly attributable to the additional assets we have placed in service since the three month period ended June 30, 2013, primarily on our Lakehead System and Eastern Access Project.

Six month period ended June 30, 2014 compared with six month period ended June 30, 2013

Our Liquids segment contributed $389.8 million of operating income during the six month period ended June 30, 2014, representing a $239.4 million increase over the $150.4 million operating income for the same period in 2013. The components comprising the operating income of our Liquids business, such as operating revenue, operating and administrative expenses, power costs, and depreciation expenses changed during the six month period ended June 30, 2014, as compared with the same period in 2013, primarily for the reasons noted above in our three month analysis in addition to the items noted below.

Operating revenue increased by $207.8 million for the six month period ended June 30, 2014, when compared with the same period in 2013, primarily due to increases in tariff rates, delivery volumes and rail revenue as discussed in our analysis above. In addition, operating revenue for the six month period ended June 30, 2014 improved due to increased related ship or pay contracts on our Bakken system of $12.6 million. This is due to a full six months of earnings from the Bakken system which went into service in March of 2013, as well as a stepped up demand charge for certain shippers. These long-term ship-or-pay contracts contain make-up-rights. Make-up-rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiration periods. We recognize revenue associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Environmental costs, net of recoveries decreased $140.5 million for the six month period ended June 30, 2014, when compared with the same period in 2013, which is primarily attributable to the change in costs accruals and insurance recoveries for Line 6B as discussed above. During the six month period ended June 30, 2014 there were $35.0 million in cost accruals compared to $215.0 million accruals for the comparable period ended June 30, 2013. There were no insurance recoveries for the six month period ended June 30, 2014 compared to $42.0 million in insurance recoveries for the comparable period ended June 30, 2013.

Future Prospects Update for Liquids

The table and discussion below summarize the Partnership's commercially secured projects for the Liquids segment, which have been recently placed into service or will be placed into service in future periods:

Projects	Total Estimated Capital Costs (in millions)	In-Service Date	Funding
Eastern Access Projects:			
Line 5, Line 62 Expansion, Line 6B Replacement	$2,400	2013—2014 [4]	Joint [1]
Eastern Access Upsize—Line 6B Expansion	310	Early 2016	Joint [1]
U.S. Mainline Expansions:			
Line 61 (ME phase 1)	160	Q3 2014	Joint [2]
Line 67 (ME phase 1)	220	Q3 2014 [3]	Joint [2]
Chicago Area Connectivity (Line 62 twin)	495	Late 2015	Joint [2]
Line 61 (ME phase 2)	1,160	2015—2016	Joint [2]
Line 67 (ME phase 3)	240	2015	Joint [2]
Line 6B 75-mile Replacement Program	390	Q2 2013—Q1 2014	EEP
Sandpiper Project	2,600	Early 2016	Joint [5]
Line 3 Replacement Program	2,600	Second half 2017	EEP [6]

(1) Jointly funded 25% by the Partnership and 75% by our General Partner under Eastern Access Joint Funding agreement. Estimated capital costs are presented at 100% before our General Partner's contributions.

(2) Jointly funded 25% by the Partnership and 75% by our General Partner under Mainline Expansion Joint Funding agreement. Estimated capital costs are presented at 100% before our General Partner's contributions.

(3) Delayed, however, throughput impacts expected to be substantially mitigated by temporary system optimization actions.

(4) As of June 30, 2014, the following projects related to the Eastern Access Projects have been put into service: (1) Line 5, (2) Line 62 Expansion and (3) a portion of the replacement of Line 6B.

(5) Since November 25, 2013, the Sandpiper Project is funded 62.5% by the Partnership and 37.5% by Williston Basin Pipeline LLC, an affiliate of Marathon Petroleum Corp., under the North Dakota Pipeline Company Amended and Restated Limited Liability Company Agreement.

(6) A special committee of independent directors of the Board of EEP has been established to consider a joint funding agreement with Enbridge Inc.

Line 3 Replacement Program

On March 3, 2014, we and Enbridge announced that shipper support was received to replace portions of the existing 1,031-mile Line 3 pipeline on the Canadian Mainline/Lakehead system between Hardisty, Alberta, Canada and Superior, Wisconsin. Our portion of the Line 3 Replacement Program, referred to as the US L3R Program, includes replacing 358 miles from the U.S./Canadian border at Neche, North Dakota to Superior, Wisconsin. Subject to regulatory and other approvals, the US L3R Program is targeted to be completed in the second half of 2017 at an estimated cost of $2.6 billion. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it supports the safety and operational reliability of the system, enhances flexibility and will allow us to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd.

The initial term of the agreement is 15 years. For purposes of the toll surcharge, the agreement specifies a 30 year recovery of the capital based on a cost of service methodology. A special committee of independent directors of the board of EEP has been established to consider a proposal from our General Partner, on behalf of Enbridge, that would establish joint funding arrangements for the US L3R Program by creating an additional jointly owned series of partnership interests in OLP similar to the series established for Alberta Clipper, Eastern Access and Mainline Expansion. We anticipate that joint funding arrangements for the US L3R Program will be completed in 2014.

Line 6B 75-mile Replacement Program

In 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments have been completed in components, with approximately 65 miles of segments placed in service in 2013. The two remaining 5-mile segments in Indiana were placed in service in March 2014. The total capital for this replacement program was approximately $390 million. These costs are currently being recovered through our FSM.

Light Oil Market Access Program

On December 6, 2012, we and Enbridge announced our plans to invest in a Light Oil Market Access Program to expand access to markets for growing volumes of light oil production. This program responds to significant recent developments with respect to supply of light oil from U.S. north central formations and western Canada, as well as refinery demand for light oil in the U.S. Midwest and eastern Canada. The Light Oil Market Access Program includes several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Project, enhance Enbridge's Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries.

Sandpiper Project

Included in the Light Oil Market Access Program is the Sandpiper Project which will expand and extend the North Dakota feeder system by 225,000 Bpd to a total of 580,000 Bpd. The proposed expansion will involve construction of an approximate 600-mile pipeline from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 Bpd North Dakota system mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 250,000 Bpd of capacity on the twin line between Tioga and Berthold, North Dakota and 225,000 Bpd of capacity on the twin line between Berthold and Clearbrook both with a new 24-inch diameter pipeline, in addition to adding 375,000 Bpd between Clearbrook and Superior with a 30-inch diameter pipeline. The Sandpiper project is expected to cost approximately $2.6 billion.

Marathon Petroleum Corporation, or MPC, has been secured as an anchor shipper for the Sandpiper project. As part of the arrangement, the Partnership, through its subsidiary, North Dakota Pipeline Company LLC, or NDPC, formerly known as Enbridge Pipelines (North Dakota) LLC, and Williston Basin Pipeline LLC, or Williston, an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of the Sandpiper Project construction and have the option to participate in other growth projects within NDPC, unless specifically excluded by the agreement; this investment is not to exceed $1.2 billion in aggregate. In return for funding part of Sandpiper's construction, Williston will obtain an approximate 27% equity interest in NDPC at the in-service date of Sandpiper, targeted for early 2016.

We filed a petition with the FERC to approve recovering Sandpiper's costs through a surcharge to the NDPC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. In March 2013, the FERC denied the petition on procedural grounds. We refiled the petition on February 12, 2014 and received approval in the form of a declaratory order from the FERC on May 16, 2014. Furthermore, in late 2013, we held an open season to solicit commitments from shippers for capacity created by the Sandpiper Project. The open season closed in late January 2014 with the receipt of a further capacity commitment which can be accommodated within the planned incremental capacity as identified above. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals.

Eastern Access Projects

Since October 2011, we and Enbridge have announced multiple expansion projects that will provide increased access to refineries in the United States Upper Midwest and the Canadian provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States. In 2013, we completed and placed into service the 50,000 Bpd capacity expansion of our Line 5 light crude line between Superior, Wisconsin and the international border at the St. Clair River. Furthermore in 2013, we completed and placed into service the expansion of the Spearhead North pipeline, or Line 62 expansion, between Flanagan, Illinois and the Terminal at Griffith, Indiana. The Line 62 expansion increased capacity from 130,000 Bpd to 235,000 Bpd by adding horsepower.

In 2012, we announced plans to replace additional sections of the our Line 6B in Indiana and Michigan, referred to as the Line 6B Replacement project, including the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, as well as tanks at Flanagan, Stockbridge and Hartsdale, to increase capacity from 240,000 Bpd to 500,000 Bpd. The replacement of the Line 6B sections are in addition to the line 6B 75-Mile Replacement Program discussed above. Portions of the existing 30-inch diameter pipeline are being replaced with 36-inch diameter pipe. The target in-service date for the Line 6B Replacement project was split into two phases, with the segment between Griffith and Stockbridge completed in May 2014 and the segment from Ortonville, Michigan to the international border at the St. Clair River now expected to be completed early in the fourth quarter of 2014. Following detailed engineering estimates completed in the first quarter of 2014 in addition to issues with local ground terrain conditions including tie-ins, the expected capital cost increased by approximately $300 million. These projects, including the previously discussed Line 5 and Line 62 expansion completions, will now cost approximately $2.4 billion and will be undertaken on a cost-of-service basis with shared capital cost risk, such that the toll surcharge will absorb 50% of any cost overruns over $1.85 billion during the Competitive Toll Settlement, or CTS, term, which runs until July 2021.

As part of the Light Oil Market Access Program announced in 2012, the Partnership will expand the Eastern Access Projects, which will include further expansion of the Line 6B component by increasing capacity from 500,000 Bpd to 570,000 Bpd and will include pump station modifications at Griffith, Niles and Mendon, additional modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. The expected cost of this expansion is now approximately $310 million, which is a decrease of $55 million from the original estimated cost as a result of a more detailed engineering estimate and a proposed tank construction being removed from the scope of the project. This further expansion of the Line 6B component is expected to begin service in early 2016.

These projects collectively referred to as the Eastern Access Projects, will cost approximately $2.7 billion. The Eastern Access Projects are now being funded at 75% by our General Partner and 25% by the Partnership under the Eastern Access Joint Funding agreement, after we exercised the option to reduce our portion of the funding by 15 percentage points on June 28, 2013. Additionally, within one year of the in-service date, scheduled for early 2016, we will have the option to increase our economic interest by up to 15 percentage points at cost.

U.S. Mainline Expansions

In 2012 and 2013, we announced further expansions projects for our mainline pipeline system including (1) expanding our existing 36-inch diameter Alberta Clipper pipeline, or Line 67; (2) expanding of the existing 42-inch diameter Southern Access pipeline, or Line 61; and (3) expanding by constructing a 76-mile, 36-inch diameter twin of the Spearhead North pipeline, or Line 62.

The initial phase of the Alberta Clipper pipeline expansion includes increasing capacity between Neche, North Dakota into the Superior, Wisconsin Terminal from 450,000 Bpd to 570,000 Bpd at an estimated cost of approximately $220 million, while the second phase will add an additional 230,000 Bpd of capacity at an estimated cost of approximately $240 million. These projects require only the addition of pumping horsepower at existing sites with no pipeline construction. Subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of the Line 67 pipeline at its currently planned operating capacity of 800,000 Bpd, the expansions will be undertaken on a full cost-of-service basis and are expected to be available for service in the third quarter of 2014 for the initial expansion to 570,000 Bpd and in 2015 for the expansion to 800,000 Bpd. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 Bpd capacity increase. Furthermore, it is anticipated that obtaining regulatory approval for the expansion to 800,000 Bpd will take longer than originally planned although approval is expected mid-2015.

The initial phase of the Southern Access pipeline expansion also includes an increase in capacity between the Superior Terminal and the Flanagan Terminal near Pontiac, Illinois from 400,000 Bpd to 560,000 Bpd at an estimated cost of approximately $160 million. The second phase of the Southern Access pipeline expansion will expand the pipeline to its full 1,200,000 Bpd potential with additional tankage requirements. The Line 61 expansion from 560,000 Bpd to 1,200,000 Bpd is now estimated to cost approximately $1.2 billion, which is a decrease of $90 million from the original estimated cost as a result of a more detailed engineering estimate. Both phases of the expansion require only the addition of pumping horsepower and crude oil tanks at existing sites with no pipeline construction. The first phase of the Line 61 expansion is expected to be available for service in the third quarter of 2014. For the second phase of the Line 61 expansion, which remains subject to regulatory and other approvals, the pump station expansion is expected to be available for service in 2015, while the additional tankage is expected to be completed in 2016.

Furthermore, as part of the Light Oil Market Access Program announced in 2012, the capacity on our Lakehead System between Flanagan, Illinois, and Griffith, Indiana will be expanded by constructing a 79-mile, 36-inch diameter twin of the Spearhead North pipeline, or Line 62, with an initial capacity of 570,000 Bpd, at an estimated cost of $495 million. Subject to regulatory and other approvals, the expansion is expected to begin service in late 2015.

These projects collectively referred to as the U.S. Mainline Expansions projects, will cost approximately $2.3 billion and will be undertaken on a cost-of-service basis. Furthermore, these projects are jointly funded by our General Partner and the Partnership, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding. On June 28, 2013, we exercised our option to decrease our economic interest and funding of the U.S. Mainline Expansions projects from 40% to 25%. Within one year of the in-service date, scheduled for 2016, the Partnership will have the option to increase its economic interest held at that time by up to 15 percentage points at cost.

Canadian Eastern Access and Mainline Expansion Projects

The Eastern Access Projects and U.S. Mainline Expansions projects complement Enbridge's strategic initiative of expanding access to new markets in North America for growing production from western Canada and the Bakken Formation.

Since October 2011, Enbridge also announced several complementary Eastern Access and Mainline Expansion Projects. These projects include: (1) partial reversal of Enbridge's Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario which was completed and placed into service in August 2013; (2) construction of a 35-mile pipeline adjacent to Enbridge's Toledo Pipeline, originating at the Partnership's Line 6B in Michigan to serve refineries in Michigan and Ohio which was completed and placed into service in May 2013; (3) reversal of Enbridge's Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec; (4) an expansion of Enbridge's Line 9B to provide additional delivery capacity within Ontario and Quebec; (5) expansions to add horsepower on existing lines on the Enbridge Mainline system from western Canada to the U.S. border; and (6) modifications to existing terminal facilities on the Enbridge Mainline system, comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections in order to accommodate additional light oil volumes and enhance operational flexibility. The outstanding projects have various targeted in-service dates through 2015. The Line 9B projects noted above are subject to fulfillment of certain conditions outlined under the Canadian National Energy Board approval received in March 2014 and are expected to be in service in the fourth quarter of 2014. These projects will enable growing light crude production from the Bakken shale and from Alberta to meet refinery needs in Michigan, Ohio, Ontario and Quebec. These projects will also provide much needed transportation outlets for light crude, mitigating the current discounting of supplies in the basins, while also providing more favorable supply costs to refiners currently dependent on crudes priced off of the Atlantic basin.

Enbridge United States Gulf Coast Projects and Southern Access Extension

A key strength of the Partnership is our relationship with Enbridge. In 2011, Enbridge announced two major United States Gulf Coast market access pipeline projects, which, when completed, will pull more volume through the Partnership's pipeline and may lead to further expansions of our Lakehead pipeline system. In addition, in 2012 Enbridge announced the Southern Access Extension, which will support the increasing supply of light oil from Canada and the Bakken into Patoka, Illinois.

Flanagan South Pipeline

Enbridge's Flanagan South Pipeline project will transport more volumes into Cushing, Oklahoma and twin its existing Spearhead pipeline, which starts at the hub in Flanagan, Illinois and delivers volumes into the Cushing hub. The 590-mile, 36-inch diameter pipeline will have a design capacity of approximately 600,000 Bpd and is expected to be mechanically complete by mid-October 2014. However, in the initial years, it is not expected to operate to its full design capacity. In August 2013, the Sierra Club and National Wildlife Federation, the Plaintiff, filed a Complaint for Declaratory and Injunctive Relief, referred to as the Complaint, with the United States District Court for the District of Columbia, or the Court. The Complaint was filed against multiple federal agencies, or the Defendants, and included a request that the Court issue a preliminary injunction suspending previously granted federal permits and ordering Enbridge to discontinue construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. In September 2013, Enbridge obtained intervener status and joined the Defendants in filing a response in opposition to the motion for preliminary injunction. The Plaintiff's request for preliminary injunction was denied by the Court in November 2013. A court hearing was held on February 21, 2014 concerning the merits of the Complaint against the federal agencies, but no decision has yet been released.

Seaway Crude Pipeline

In 2011, Enbridge completed the acquisition of a 50% interest in the Seaway Crude Pipeline System, or Seaway. Seaway is a 670-mile pipeline that includes a 500-mile, 30-inch pipeline long-haul system that was reversed in 2012 to enable transportation of oil from Cushing, Oklahoma to Freeport, Texas, as well as a Texas City Terminal and Distribution System that serves refineries in the Houston and Texas City areas. Seaway also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and provided an initial capacity of 150,000 Bpd. Further pump station additions and modifications completed in January 2013 have increased the capacity to approximately 400,000 Bpd, depending upon the mix of light and heavy grades of crude oil.

In March 2012, based on additional capacity commitments from shippers, plans were announced to proceed with an expansion of the Seaway Pipeline through construction of a second line to more than double its capacity to 850,000 Bpd. As of July 2014, this 30-inch diameter pipeline was mechanically complete and follows the same route as the existing Seaway Pipeline. Included in the scope of this second line was a 65-mile, 36-inch diameter pipeline lateral from the Seaway Jones Creek facility to Enterprise Product Partners L.P.'s, or Enterprise Product's, ECHO crude oil terminal, or ECHO Terminal, in Houston, Texas was completed in January 2014. Furthermore, the 100-mile pipeline from Enterprise Product's ECHO Terminal to the Port Arthur/ Beaumont, Texas refining center to provide shippers access to the region's heavy oil refining capabilities was substantially completed in July 2014. The new 100-mile pipeline offers incremental capacity of 750,000 Bpd.

Southern Access Extension

In December 2012, Enbridge announced that it would undertake the Southern Access Extension project, which will consist of the construction of a 165-mile, 24-inch diameter crude oil pipeline from Flanagan to Patoka, Illinois, as well as additional tankage and two new pump stations. The initial capacity of the new line is expected to be approximately 300,000 Bpd. Effective July 1, 2014, Enbridge entered into an agreement with Lincoln Pipeline LLC, or Lincoln, an affiliate of MPC, to, among other things, admit Lincoln as a partner and participate in the Southern Access Extension. Lincoln has purchased a 35% equity interest in the project and will make additional cash contributions in accordance with the Southern Access Extension's spend profile in proportion to its 35% interest. Subject to regulatory and other approvals, the project is expected to be placed into service in mid-2015.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment and approximate average daily volumes of natural gas throughput and NGLs produced on our major systems for the periods presented.

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenues	$ 1,396.8	$ 1,306.4	$ 3,043.7	$ 2,666.5
Cost of natural gas	1,259.8	1,115.5	2,748.5	2,306.9
Operating and administrative	103.6	116.4	212.5	224.2
Depreciation and amortization	36.8	35.4	73.8	70.8
Operating expenses	1,400.2	1,267.3	3,034.8	2,601.9
Operating income (loss)	(3.4)	39.1	8.9	64.6
Other income	2.3	—	1.0	—
Net income (loss)	$ (1.1)	$ 39.1	$ 9.9	$ 64.6
Operating Statistics (MMBtu/d)				
East Texas	1,029,000	1,211,000	1,000,000	1,231,000
Anadarko	826,000	972,000	825,000	968,000
North Texas	300,000	344,000	286,000	338,000
Total	2,155,000	2,527,000	2,111,000	2,537,000
NGL Production (Bpd)	83,480	91,251	82,004	89,900

Three month period ended June 30, 2014, compared with three month period ended June 30, 2013

The operating income of our Natural Gas business for the three month period ended June 30, 2014, decreased $42.5 million, as compared with the same period in 2013. The most significant area affected was the Natural Gas segment gross margin, representing revenue less cost of natural gas, which decreased $53.9 million for the three month period ended June 30, 2014, as compared with the same period in 2013.

Segment gross margin was impacted by the decrease in unrealized, non-cash, mark-to-market net losses of $33.1 million for the three month period ended June 30, 2014, compared to the same period in 2013, due to losses on our equity gas hedges, hedge ineffectiveness, and overall physical commodity losses from the non-qualifying physical natural gas, NGL, and crude oil contracts.

The following table depicts the effect that non-cash, mark-to-market net gains and losses had on the operating results of our Natural Gas segment for the three and six month periods ended June 30, 2014 and 2013:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Hedge ineffectiveness	$ (1.1)	$ 1.8	$ 0.6	$ 2.3
Non-qualified hedges	(9.7)	20.5	(6.8)	18.5
Derivative fair value gains (losses)	$(10.8)	$22.3	$(6.2)	$20.8

We are exposed to fluctuations in commodity prices in the near term on approximately 40% of the physical natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our segment gross margin generally increases when the prices of these commodities are rising and generally decreases when the prices are declining.

Additionally, the segment gross margin for our Natural Gas segment was affected by the reduced production volumes which negatively affected segment gross margin by approximately $17.4 million for the three month period ended June 30, 2014, compared to the same period in 2013. The average daily volumes of our major systems for the three month period ended June 30, 2014, decreased by approximately 372,000 MMBtu/d, or 15%, when compared to the same period in 2013. The average NGL production for the three month period ended June 30, 2014, decreased 7,771 Bpd, or 9%, when compared to the same period in 2013. The decrease in volumes in the Anadarko region was primarily attributable to reduced drilling activity by certain producers, and the loss of a major customer. The decrease in volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions.

The natural gas and NGL production volume outlook on our systems is expected to improve as we progress through 2014. We expect producer drilling plans to accelerate in each of our asset regions later in the year. Additionally, drilling activity by natural gas producers in all regions is expected to target rich gas and oil prospects. This is notable in East Texas where existing processing capacity is full. Completion of the Beckville Cryogenic Processing Plant, which is expected to commence service in early 2015, is expected to alleviate this capacity constraint.

A variable element of the operating results of our Natural Gas segment is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts, we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to the barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the three month period ended June 30, 2014, decreased $4.9 million from the same period in 2013.

Operating income decreased $1.3 million for the three month period ended June 30, 2014, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs, when compared with the same period in 2013. On our Anadarko system, we purchase certain NGL components at Conway hub prices and then have the option to resell those same NGL components at Mont Belvieu hub prices. For the three months ended June 30, 2014, the prevailing price for NGLs increased approximately 17% per composite barrel at the Conway pricing hub, while increasing approximately 10% per composite barrel at the Mont Belvieu pricing hub, in each case as compared with the prevailing composite barrel prices for the same period in 2013.

The decrease in segment gross margin was offset in part by an increase of $4.4 million for the three months ended June 30, 2014, related to contractual minimum volume commitment contracts in which our customer has not moved the required volumes.

Operating and administrative costs of our Natural Gas segment decreased $12.8 million for the three month period ended June 30, 2014, compared to the same period in 2013, primarily related to lower administrative and pipeline integrity costs.

Depreciation and amortization expense for our Natural Gas segment increased $1.4 million for the three month period ended June 30, 2014, compared with the same period of 2013, due to additional assets that were put in service.

We recognized a $2.3 million equity income in "Other income (expense)" on our consolidated statement of income related to our investment in the Texas Express NGL system, which commenced startup operations during the fourth quarter of 2013. The Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiry periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. For the three month period ended June 30, 2014, the deferred revenue on the ship or pay contracts amounted to $1.1 million.

Six month period ended June 30, 2014, compared with six month period ended June 30, 2013

The operating income of our Natural Gas business for the six month period ended June 30, 2014, decreased $55.7 million, as compared with the same period in 2013. The most significant area affected was the Natural Gas segment gross margin, representing revenue less cost of natural gas, which decreased $64.4 million for the six month period ended June 30, 2014, as compared with the same period in 2013.

The segment gross margin for our Natural Gas segment was affected by the reduced production volumes which negatively affected segment gross margin by approximately $35.3 million for the six month period ended June 30, 2014, compared to the same period in 2013. The average daily volumes of our major systems for the six month period ended June 30, 2014, decreased by approximately 426,000 MMBtu/d, or 17%, when compared to the same period in 2013. The average NGL production for the six month period ended June 30, 2014, decreased by 7,896 Bpd, or 9%, when compared to the same period in 2013. These decreases in volumes on our major systems were primarily attributable to reduced drilling activity by certain producers in the Anadarko region, reduced dry gas drilling, and delayed drilling activity and well completions in East Texas.

Segment gross margin was impacted by the decrease in non-cash, mark-to-market net losses of $27.0 million for the six month period ended June 30, 2014, compared to the same period in 2013 due to losses on our equity gas hedges, hedge ineffectiveness, and overall physical commodity losses from the non-qualifying physical natural gas, NGL, and crude oil contracts.

Operating revenue less the cost of natural gas derived from keep-whole earnings for the six month period ended June 30, 2014, decreased $12.4 million from the same period in 2013.

Operating income decreased approximately $3.0 million for six month period ended June 30, 2014, primarily due to the impact of sustained freezing temperatures in the first quarter 2014, which significantly disrupted producer well head production levels and our pipeline operations.

Operating income decreased $2.2 million for the six month period ended June 30, 2014, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same period in 2013. On our Anadarko system, we purchase certain NGL components at Conway hub prices and then have the option to resell those same NGL components at Mont Belvieu hub prices. For the six months ended June 30, 2014, the prevailing price for NGLs increased approximately 20% per composite barrel at the Conway pricing hub, while increasing approximately 13% per composite barrel at the Mont Belvieu pricing hub, in each case as compared with the prevailing composite barrel prices for the same period in 2013.

The decrease in segment gross margin was partially offset by an increase of $4.4 million for the six months ended June 30, 2014, related to contractual minimum volume commitment contracts in which our customer has not moved the required volumes.

Operating and administrative costs of our Natural Gas segment decreased $11.7 million for the six month period ended June 30, 2014, compared to the same period in 2013, primarily related to lower administrative and pipeline integrity costs.

Depreciation and amortization expense for our Natural Gas segment increased $3.0 million, for the six month period ended June 30, 2014, compared with the same period of 2013, due to additional assets that were put in service.

We recognized $1.0 million in equity earnings in "Other income (expense)" on our consolidated statements of income related to our investment in the Texas Express NGL system, which commenced startup operations during the fourth quarter of 2013. The Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiry periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. For the six month period ended June 30, 2014, the deferred revenue on the ship or pay contracts amounted to $3.2 million.

Future Prospects for Natural Gas

We intend to expand our natural gas gathering and processing services through internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value. The paragraph below summarizes the Partnership's commercially secured project for the Natural Gas segment, which we expect to place into service in future periods.

Beckville Cryogenic Processing Plant

In April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville processing plant. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation. We expect our Beckville processing plant to be capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. We estimate the cost of constructing the plant to be approximately $145 million and expect it to commence service in early 2015.

The project is funded by the Partnership and MEP based on their proportionate ownership percentages in Midcoast Operating, which was 61% and 39%, respectively, at June 30, 2014. On July 1, 2014, MEP acquired an additional 12.6% interest in Midcoast Operating from us for $350 million. The Partnership's and MEP's ownership in Midcoast Operating is 48.4% and 51.6%, respectively, after the transaction date. For additional information on this transaction, see Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations—Subsequent Events*.

Corporate

Our corporate activities consist of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	**2013**	**2014**	**2013**
	(in millions)			
Operating Results:				
Operating and administrative expenses	$ 3.4	$ 3.2	$ 3.1	$ 3.6
Operating loss	(3.4)	(3.2)	(3.1)	(3.6)
Interest expense, net	80.2	79.5	157.1	155.9
Allowance for equity used during construction	12.6	8.1	33.3	15.9
Other income (expense)	(1.1)	0.3	(0.6)	0.6
Income tax expense	2.0	14.2	4.0	16.0
Net loss	(74.1)	(88.5)	(131.5)	(159.0)
Noncontrolling interest	42.4	18.4	78.7	34.0
Series 1 preferred unit distributions	22.5	13.1	45.0	13.1
Accretion of discount on Series 1 preferred units	3.7	2.3	7.3	2.3
Net loss attributable to general and limited partners	$(142.7)	$(122.3)	$(262.5)	$(208.4)

Our interest cost for the three and six month periods ended June 30, 2014 and 2013 is comprised of the following:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	**2013**	**2014**	**2013**
	(in millions)			
Interest expense	$80.2	$79.5	$157.1	$155.9
Interest capitalized	10.2	12.1	24.1	26.4
Interest cost incurred	$90.4	$91.6	$181.2	$182.3
Weighted average interest rate	*6.2%*	*6.1%*	*6.4%*	*6.1%*

Three month period ended June 30, 2014, compared with three month period ended June 30, 2013

The $14.4 million decrease in our net loss for the three month period ended June 30, 2014, as compared to the same period in 2013 was primarily attributable to the allowance for equity used during construction, or AEDC, and income tax expense.

Income tax expense decreased $12.2 million for the three month period ended June 30, 2014, compared to the same period in June 30, 2013, primarily due to $6.6 million of income tax expense recognized for the three month period ended June 30, 2013, related to the Texas Legislature passing House Bill 500, or HB 500, which was subsequently signed into law in June 2013. The most significant change in the law for us is that HB 500 allows a pipeline company that transports oil, gas, or other petroleum products owned by others to subtract as Cost of Goods Sold, its depreciation, operations, and maintenance costs related to the services provided. Under the new law, we are allowed additional deductions against income for Texas margin tax purposes. The decrease in income taxes period-to-period is a result of the change in this law. See Note 11. *Income Taxes* for further discussion regarding this new tax law.

AEDC increased $4.5 million for the three month period ended June 30, 2014, compared with the corresponding period in 2013, primarily related to our Eastern Access projects, which also contributed to the decrease in net loss.

Six month period ended June 30, 2014, compared with six month period ended June 30, 2013

The results for corporate activities for the six month period ended June 30, 2014, compared to the same period in 2013, changed for the same reasons as noted in the three month analysis above.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge, including our General Partner. In connection with the joint funding arrangement, we allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $11.6 million and $13.3 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three month periods ended June 30, 2014 and 2013, respectively. We allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $21.7 million and $26.2 million to our General Partner for the six month periods ended June 30, 2014, and June 30, 2013, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Joint Funding Arrangement for Eastern Access Projects

In May 2012, the OLP amended and restated its partnership agreement to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% of all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points at cost. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013, pursuant to Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $27.2 million and $5.1 million to our General Partner for its ownership of the EA interest for the three month periods ended June 30, 2014, and June 30, 2013, respectively. We allocated earnings derived from the Eastern Access Projects in the amount of $48.8 million and $7.8 million to our General Partner for the six month periods ended June 30, 2014, and June 30, 2013, respectively. We have presented this amount we allocated to our General Partner in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Joint Funding Arrangement for the U.S. Mainline Expansion

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. We received $12.0 million from our General Partner in consideration for our economic interest. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points at costs.

We allocated earnings from the Mainline Expansion Projects in the amount of $5.7 million and $10.1 million to our General Partner for its ownership of the ME interest for the three and six month periods ended June 30, 2014. We have presented the amount we allocated to our General Partner in "Net income attributable to noncontrolling interest" in our consolidated statements of income.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

Our primary source of short-term liquidity is provided by our $1.5 billion commercial paper program, which is supported by our $1.975 billion senior unsecured revolving credit facility, which we refer to as the Credit Facility, and our $1.2 billion credit agreement, which we refer to as the 364-Day Credit Facility. We refer to the 364-Day Credit Facility and the Credit Facility as our Credit Facilities. We access our $1.5 billion commercial paper program primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities.

As set forth in the following table, we had approximately $2.1 billion of liquidity available to us at June 30, 2014, to meet our ongoing operational, investment and financing needs, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil releases on Lines 6A and 6B. In addition, MEP had $0.6 billion of available liquidity from cash on hand and under the MEP Credit Agreement as set forth in the following table.

	EEP	MEP
	(in millions)	
Cash and cash equivalents	$ 113.9	$236.0
Total credit available under EEP's Credit Facilities	3,175.0	—
Total credit available under MEP's Credit Agreement	—	850.0
Less: Amounts outstanding under MEP's Credit Agreement	—	475.0
Principal amount of commercial paper issuances	1,065.0	—
Letters of credit outstanding	160.3	—
Total	$2,063.6	$611.0

General

Our primary operating cash requirements consist of normal operating expenses, maintenance capital expenditures, distributions to our partners and payments associated with our risk management activities. We expect to fund our current and future short-term cash requirements for these items from our operating cash flows supplemented as necessary by issuances of commercial paper and borrowings on our Credit Facilities. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facilities.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses through organic growth and targeted acquisitions. We expect to initially fund our long-term cash requirements for expansion projects and acquisitions, as well as retire our maturing and callable debt, first from operating cash flows and then from issuances of commercial paper and borrowings on our Credit Facilities. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all. In addition, we intend to sell additional interests in Midcoast Operating entity to MEP to raise capital over the course of the next several years. Although this is our intent, there is no assurance that any transactions will occur as they are subject to, among other things, obtaining agreement from MEP and its board of directors around the commercial terms of such a sale. When we have attractive growth opportunities in excess of our own capital raising capabilities, the General Partner has provided supplementary funding, or participated directly in projects, to enable us to undertake such opportunities. If in the future we have attractive growth opportunities that exceed capital raising capabilities, we could seek similar arrangements from the General Partner, but there can be no assurance that this funding can be obtained.

As of June 30, 2014, we had a working capital deficit of approximately $1.0 billion and approximately $2.1 billion of liquidity to meet our ongoing operational, investing and financing needs as of June 30, 2014, as shown above, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil releases on Lines 6A and 6B. In addition, MEP had $0.6 billion of available liquidity from cash on hand and under its Credit Agreement.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these activities. We have issued a balanced combination of debt and equity securities to fund our expansion projects and acquisitions. Our internal growth projects and targeted acquisitions will require additional permanent capital and require us to bear the cost of constructing and acquiring assets before we begin to realize a return on them. If market conditions change and capital markets again become constrained, our ability and willingness to complete future debt and equity offerings may be limited. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Series 1 Preferred Unit Purchase Agreement

On May 7, 2013, we entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our Series 1 Preferred Units, representing limited partner interests in us, for aggregate proceeds of approximately $1.2 billion. The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset every five years. However, these quarterly cash distributions, during the first full eight quarters ending June 30, 2015, will accrue and accumulate, which we refer to as the Payment Deferral. Thus we will accrue, but not pay these amounts until the earlier of the fifth anniversary of the issuance of the Preferred Units or our redemption of the Preferred Units. The quarterly cash distribution for the three month period ended June 30, 2013 was prorated from May 8, 2013. The preferred unit distributions for the six month period ended June 30, 2014 were $45 million, all of which were deferred. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) we use the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies' treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions, including the Payment Deferral.

We issued the Preferred Units at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders' and General Partner's capital and a decrease in Preferred Unitholders' capital to reflect the fair value of the Preferred Units at issuance on our consolidated statement of partners' capital for the six month period ended June 30, 2013. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013, through the first conversion date, which is June 1, 2016, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders' capital. The impact of accretion of the beneficial conversion feature of $3.7 million and $7.3 million is also included in earnings per unit for the three and six month periods ended June 30, 2014, respectively.

We used the proceeds from the Preferred Unit issuance to repay commercial paper, to finance a portion of our capital expansion program relating to our core liquids and natural gas systems and for general partnership purposes.

Equity Distribution Agreement

In June 2010, we entered into an Equity Distribution Agreement, or EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $150.0 million. On May 27, 2011, the Partnership entered into the Amended and Restated Equity Distribution Agreement, or Amended EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $500.0 million from the execution date of the agreement through May 20, 2014. Under the EDA and Amended EDA, we sold 3,084,208 Class A common units, for aggregate gross proceeds of $124.8 million. No further sales were made under that agreement. The Amended EDA terminated in accordance with its terms on May 20, 2014.

Midcoast Energy Partner, L.P.

On November 13, 2013, MEP, one of our subsidiaries, completed its IPO of 18,500,000 Class A common units representing limited partner interests and subsequently issued an additional 2,775,000 Class A common units pursuant to the underwriter's over allotment option. MEP received proceeds (net of underwriting discounts, structuring fees and offering expenses) of approximately $354.9 million. MEP used the net proceeds to distribute approximately $304.5 million to us, to pay approximately $3.4 million in revolving credit facility origination and commitment fees and used approximately $47.0 million to redeem 2,775,000 Class A common units from us. At June 30, 2014, we owned 5.9% of outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 61% of the limited partner interests in Midcoast Operating.

On June 18, 2014, we agreed to sell a 12.6% limited partner interest in Midcoast Operating to MEP, for $350.0 million in cash, which brought our total ownership interest in Midcoast Operating to 48.4%. This transaction closed on July 1, 2014 and represents our first disposition of additional interests in Midcoast Operating since MEP's IPO on November 13, 2013. We intend to sell additional interests in our natural gas assets, held through Midcoast Operating, to MEP and use the proceeds from any such sale as a source of funding for us. However, we do not know when, or if, any additional interests will be offered for sale.

Investments

In March and September 2013, Enbridge Management completed public offerings of 10,350,000 and 8,424,686 Listed Shares, respectively, representing limited liability company interests with limited voting rights, at a price to the underwriters of $26.44 and $28.02 per Listed Share, respectively. Enbridge Management received net proceeds of $272.9 million and $235.6 million for the March and September 2013 issuances, respectively, which we subsequently invested in an equal number of the Partnership's i-units. We used the proceeds from our sale of i-units to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our Credit Facilities. We have a $1.5 billion commercial paper program that is supported by our Credit Facilities, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities.

Credit Facilities

We have a committed senior unsecured revolving credit facility, which we refer to as the Credit Facility, that permits aggregate borrowings of up to, at any one time outstanding, $1.975 billion. The maturity date on the Credit Facility is September 26, 2018.

We also have a credit agreement, which we refer to as the 364-Day Credit Facility, that provided aggregate lending commitments of up to $1.2 billion: (1) on a revolving basis for a 364-day period, extendible annually at the lenders' discretion, and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods.

On July 3, 2014, we amended our 364-Day Credit Facility to extend the revolving credit termination date to July 3, 2015, and to decrease aggregate commitments under the facility by $550.0 million. After these changes, our 364-day Credit Facility now provides to us aggregate lending commitments of $650.0 million.

We refer to our Credit Facility and our 364-Day Credit Facility as the Credit Facilities, which provided an aggregate amount of approximately $3.2 billion of bank credit, as of June 30, 2014, which we use to fund our general activities and working capital needs.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. Our policy is to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at any time. Taking that policy into account, at June 30, 2014, we could borrow approximately $1.9 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$3,175.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	1,065.0
Letters of credit outstanding	160.3
Total amount we could borrow at June 30, 2014	$1,949.7

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the three and six month periods ended June 30, 2014 and 2013, we did not have any LIBOR rate borrowings or base rate borrowings.

As of June 30, 2014, we were in compliance with the terms of all of our financial covenants under the Credit Facilities.

On February 3, 2014, we entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank's sole discretion, we view this arrangement as a liquidity enhancement as it allows us to potentially reduce our reliance on utilizing our committed Credit Facilities for issuance of letters of credit to support our hedging activities.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At June 30, 2014, we had approximately $1.1 billion in principal amount of commercial paper outstanding at a weighted average interest rate of 0.33%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $765.0 million during the six month period ended June 30, 2014, which includes gross borrowings of $4.4 billion and gross repayments of $3.6 billion. At December 31, 2013, we had $300.0 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.37%, excluding the effect of our interest rate hedging activities. Our policy is to limit the amount of commercial paper we can issue by the amounts available under our Credit Facility up to an aggregate principal amount of $1.5 billion.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our Credit Facilities. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

Senior Notes

All of our senior notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our senior notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $200.0 million of senior notes issued by Enbridge Energy, Limited Partnership, or the OLP, which we refer to as the OLP Notes. The borrowings under our senior notes are non-recourse to our General Partner and Enbridge Management. All of our senior notes either pay or accrue interest semi-annually and have varying maturities and terms.

The OLP, our operating subsidiary that owns the Lakehead system, has $200.0 million of senior notes outstanding representing unsecured obligations that are structurally senior to our senior notes. The OLP Notes consist of $100.0 million of 7.000% senior notes due in 2018 and $100.0 million of 7.125% senior notes due in 2028. All of the OLP Notes pay interest semi-annually.

Junior Subordinated Notes

The $400.0 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes, represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make cash distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

MEP Credit Agreement

On November 13, 2013, MEP, Midcoast Operating L.P., or Midcoast Operating, and their material domestic subsidiaries, entered into a senior revolving credit facility, which we refer to as the MEP Credit Agreement, that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million. The original term of the MEP Credit Agreement is three years with an initial maturity date of November 2016, subject to four one-year requests for extensions. At June 30, 2014, MEP had $475.0 million in outstanding borrowings under the MEP Credit Agreement at a weighted average interest rate of 1.9%. Under the MEP Credit Agreement, MEP had net borrowings of approximately $140.0 million during the six month period ended June 30, 2014, which includes gross borrowings of $3.4 billion and gross repayments of $3.3 billion. At June 30, 2014, MEP was in compliance with the terms of its financial covenants.

Joint Funding Arrangements

In order to obtain the required capital to expand our various pipeline systems, we have determined that the required funding would challenge the Partnership's ability to efficiently raise capital. Accordingly, we have explored numerous options and determined that several joint funding arrangements would provide the best source of available capital to fund the expansion projects.

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010.

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the investment our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement to finance any additional costs associated with the construction of our portion of the Alberta Clipper Pipeline we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. At June 30, 2014, we had approximately $312.0 million outstanding under the A1 Term Note.

Our General Partner made no equity contributions to the OLP during the six month periods ended June 30, 2014 and 2013, respectively, to fund its equity portion of the construction costs associated with Alberta Clipper Pipeline. The OLP paid a distribution of $12.8 million and $28.7 million to our General Partner and its affiliate during the six month periods ended June 30, 2014 and 2013, respectively, for their noncontrolling interest in the Series AC, representing limited partner ownership interests of the OLP that are specifically related to the assets, liabilities and operations of the Alberta Clipper Pipeline.

Joint Funding Arrangement for Eastern Access Projects

In May 2012, the OLP amended and restated its limited partnership agreement to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% of all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points at cost. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

Our General Partner has made equity contributions totaling $360.8 million to the OLP during the six month period ended June 30, 2014 to fund its equity portion of the construction costs associated with the Eastern Access Projects.

Joint Funding Arrangement for Mainline Expansion Projects

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the project from 40% to 25%. Within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points at cost. We received $12.0 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to the Mainline Expansion Projects.

Our General Partner has made equity contributions totaling $177.7 million and $59.5 to the OLP for the six month periods ended June 30, 2014 and 2013, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

Midcoast Energy Partners, L.P.

On November 13, 2013, as part of the IPO, EEP conveyed a 39% interest in Midcoast Operating to MEP. On July 1, 2014 EEP sold an additional 12.6% interest in Midcoast Operating to MEP, which brought EEP's total ownership interest in Midcoast Operating to 48.4%. Under the Midcoast Operating Agreement, EEP and MEP each have the option to contribute its proportionate share of additional capital to Midcoast Operating if any additional capital contributions are necessary to fund capital expenditures or other growth projects. To the extent that MEP or EEP elect not to make any such capital contributions, the contributing party will be permitted to make additional capital contributions in exchange for additional interests in Midcoast Operating. EEP can elect not to participate in certain growth projects. We expect to participate proportionately in these natural gas capital projects, although there is no guarantee that we will do so.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, which we refer to as the Receivables Agreement, with an indirect wholly-owned subsidiary of Enbridge which was amended on September 20, 2013, and again on December 2, 2013. The Receivables Agreement and the transactions contemplated thereby were approved by the special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivable and accrued receivables, or the receivables, of the respective subsidiaries initially up to a monthly maximum of $450.0 million. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "Operating and administrative-affiliate" expense in our consolidated statements of income. For the three and six month periods ended June 30, 2014, the cost stemming from the discount on the receivables sold was not material. For the three and six month periods ended June 30, 2014, we sold and derecognized $1,236.0 million and $2,532.7 million of receivables to the Enbridge subsidiary, respectively. For the three and six month periods ended June 30, 2014, the cash proceeds were $1,235.7 million and $2,532.1 million, respectively, which was remitted to the Partnership through our centralized treasury system. As of June 30, 2014, $408.1 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of June 30, 2014 and December 31, 2013, we have $33.3 million and $69.4 million, respectively, included in "Restricted cash" on our consolidated statements of financial position, consisting of cash collections related to the Receivables sold that have yet to be remitted to the Enbridge subsidiary as of June 30, 2014.

Cash Requirements

Capital Spending

We expect to make additional expenditures during the remainder of the year for the acquisition and construction of natural gas processing and crude oil transportation infrastructure. In 2014, we expect to spend approximately $1.7 billion on system enhancements and other projects associated with our liquids and natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. We expect to receive funding of approximately $1.2 billion from our General Partner based on our joint funding arrangement for the Eastern Access Projects and Mainline Expansion Projects and $145.0 million from MPC based on joint funding arrangement on the Sandpiper Project. We recognized capital expenditures of $1.1 billion for the six month period ending June 30, 2014, including $59.3 million on maintenance capital activities, $17.3 million in contributions to the Texas Express Pipeline and $612.9 million of expenditures that were financed by contributions from our General Partner and MPC via joint funding arrangements. At June 30, 2014, we had approximately $1.1 billion in outstanding purchase commitments, before contributions from our joint funding arrangements with our General Partner, attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2014.

Acquisitions

We continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing them. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under our Credit Facilities and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

Forecasted Expenditures

We categorize our capital expenditures as either maintenance capital or enhancement expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or completing its useful life. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as maintenance capital expenditures. Enhancement expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. The following table sets forth our estimates of capital expenditures we expect to make for system enhancement and maintenance capital for the year ending December 31, 2014. Although we anticipate making these expenditures in 2014, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, regulatory permitting, changes in supplier prices or poor economic conditions, which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets. For the full year ending December 31, 2014, we anticipate the capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
Liquids Projects	
Eastern Access Projects	$ 930
U.S. Mainline Expansions	730
Sandpiper	390
Line 6B 75-mile Replacement Program	10
Line 3 Replacement	115
Liquids Integrity Program	335
System Enhancements	320
Maintenance Capital Activities	75
	2,905
Less joint funding from:	
General Partner [(1)]	1,245
Third parties	145
Liquids Total	$1,515
Natural Gas Projects	
Beckville Cryogenic Processing Plant	$ 105
System Enhancements	180
Maintenance Capital Activities	60
	345
Less joint funding from:	
MEP [(2)]	160
Natural Gas Total	185
TOTAL	$1,700

(1) No joint funding of the Line 3 Replacement is included in this line item as the joint funding agreement with Enbridge Inc. has not been finalized and approved by a special committee of independent directors of the board of EEP.

(2) Joint funding is based upon six months of MEP at a 39% ownership of Midcoast Operating and six months of MEP at a 51.6% ownership of Midcoast Operating.

We maintain a comprehensive integrity management program for our pipeline systems, which relies on the latest technologies that include internal pipeline inspection tools. These internal pipeline inspection tools identify internal and external corrosion, dents, cracking, stress corrosion cracking and combinations of these conditions. We regularly assess the integrity of our pipelines utilizing the latest generations of metal loss, caliper and crack detection internal pipeline inspection tools. We also conduct hydrostatic testing to determine the integrity of our pipeline systems. Accordingly, we incur substantial expenditures each year for our integrity management programs.

Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature, while expenditures to inspect and test our pipelines are usually considered operating expenses. The capital spending components of our programs have increased over time as our pipeline systems age.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital will continue to increase due to the growth of our pipeline systems and the aging of portions of these systems. Maintenance capital expenditures are expected to be funded by operating cash flows.

We anticipate funding system enhancement capital expenditures temporarily through borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate.

Environmental

Lakehead Line 6B Crude Oil Release

During the six month period ended June 30, 2014, our cash flows were impacted by the approximate $65.0 million we paid for the environmental remediation, restoration and cleanup activities resulting from the crude oil releases that occurred in 2010 on Line 6B of our Lakehead system. We expect to pay the majority of the total remaining estimated cost of $224.5 million related to the Order received from the EPA during 2014.

In March 2013, we and Enbridge filed a lawsuit against the insurers of our remaining $145.0 million coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of $42.0 million from the other remaining insurers during the third quarter 2013 and have since amended our lawsuit, such that it now includes only one carrier. While we believe that our claims for the remaining $103.0 million are covered under the policy, there can be no assurance that we will prevail in this lawsuit.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and interest rates and to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices or interest rates.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at June 30, 2014 for each of the indicated calendar years:

	Notional	2014	2015	2016	2017	2018	Total
			(in millions)				
Swaps							
Natural gas (1)	63,567,773	$(0.7)	$(0.3)	$(0.1)	$—	$—	$(1.1)
NGL (2)	2,765,780	(5.2)	(1.0)	—	—	—	(6.2)
Crude Oil (2)	2,209,443	(6.1)	1.8	0.2	—	—	(4.1)
Options							
Natural gas—puts written (1)	3,297,000	(0.1)	(0.6)	—	—	—	(0.7)
Natural gas—puts purchased (1)	7,870,000	0.1	1.0	0.4	—	—	1.5
Natural gas—calls written (1)	2,924,500	—	(0.2)	(0.3)	—	—	(0.5)
Natural gas—calls purchased (1)	1,277,500	—	0.2				0.2
NGL—puts purchased (2)	2,011,650	1.3	4.3	1.3	—	—	6.9
NGL—calls purchased (2)	46,000	0.1	—	—	—	—	0.1
NGL—calls written (2)	1,034,000	(0.6)	(2.1)	(1.8)	—	—	(4.5)
Crude Oil—puts purchased (2)	986,700	—	1.2	1.5	—	—	2.7
Crude Oil—calls written (2)	986,700	—	(4.9)	(3.4)	—	—	(8.3)
Forward contracts							
Natural gas (1)	233,150,574	0.5	0.5	0.1	0.1	—	1.2
NGL (2)	20,891,067	5.1	1.2	—	—	—	6.3
Crude Oil (2)	999,242	(2.3)	—	—	—	—	(2.3)
Power (3)	29,510	(0.2)	—	—	—	—	(0.2)
Totals		$(8.1)	$ 1.1	$(2.1)	$ 0.1	$—	$(9.0)

(1) Notional amounts for natural gas are recorded in MMBtu.
(2) Notional amounts for NGLs and crude oil are recorded in Barrels, or Bbl.
(3) Notional amounts for power are recorded in Megawatt hours, or MWh.

The following table provides summarized information about the timing and estimated settlement amounts of our outstanding interest rate derivatives calculated based on implied forward rates in the yield curve at June 30, 2014 for each of the indicated calendar years:

	Notional Amount	2014	2015	2016	2017	2018	Thereafter	Total (1)
				(in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$1,200.0	$ (4.2)	$(8.2)	$ (5.1)	$(0.4)	$ 0.1	$—	$ (17.8)
Pre-issuance hedges (2)	$2,350.0	(242.3)	—	25.6	—	—	—	(216.7)
		$(246.5)	$(8.2)	$20.5	$(0.4)	$ 0.1	$—	$(234.5)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $3.4 million of gains at June 30, 2014.
(2) Includes $3.3 million of cash collateral at June 30, 2014.

Cash Flow Analysis

The following table summarizes the changes in cash flows by operating, investing and financing for each of the periods indicated:

	For the six month period ended June 30, 2014	For the six month period ended June 30, 2013	Variance 2014 vs. 2013 Increase (Decrease)
	(in millions)		
Total cash provided by (used in):			
Operating activities	$ 359.6	$ 477.5	$(117.9)
Investing activities	(1,287.0)	(993.8)	(293.2)
Financing activities	1,112.5	315.7	796.8
Net increase (decrease) in cash and cash equivalents	185.1	(200.6)	385.7
Cash and cash equivalents at beginning of year	164.8	227.9	(63.1)
Cash and cash equivalents at end of period	$ 349.9	$ 27.3	$ 322.6

Operating Activities

Net cash provided by our operating activities decreased $117.9 million for the six month period ended June 30, 2014 compared to the same period in 2013, primarily due to a decrease in our working capital accounts of $229.0 million. This decrease, due to our working capital accounts, was offset by a $212.2 million increase in net income offset by non-cash items of $101.1 million for the six month period ended June 30, 2014 as compared to the same period in 2013.

Changes in our working capital accounts are shown in the following table and discussed below:

	For the six month period ended June 30, 2014	For the six month period ended June 30, 2013	Variance 2014 vs. 2013
	(in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 9.1	$ 60.1	$ (51.0)
Due from General Partner and affiliates	5.3	4.5	0.8
Accrued receivables	51.8	276.3	(224.5)
Inventory	(75.7)	(95.1)	19.4
Current and long-term other assets	(16.5)	(19.1)	2.6
Due to General Partner and affiliates	(6.0)	18.4	(24.4)
Accounts payable and other	(63.8)	(40.3)	(23.5)
Environmental liabilities	(62.9)	(32.7)	(30.2)
Accrued purchases	(3.2)	(95.3)	92.1
Interest payable	1.4	4.1	(2.7)
Property and other taxes payable	(1.6)	(14.0)	12.4
Net change in working capital accounts	$(162.1)	$ 66.9	$(229.0)

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the six month period ended June 30, 2014, compared to the same period in 2013, is primarily the result of items listed below coupled with general timing differences for cash receipts and payment associated with our third-party accounts. The main items affecting our cash flows from operating assets and liabilities include the following:

- The change in trade receivables from December 31, 2012 to June 30, 2013 was primarily due to the sale of $79.8 million of trade receivables to a subsidiary of Enbridge pursuant to the Receivables

Agreement. This sale was partially offset by increased billings due to our Bakken projects entering service in March 2013 coupled with general timing differences in billing and receipt of payments. The change in trade receivables from December 31, 2013 to June 30, 2014 was primarily due to collecting \$8.5 million more receivables than we sold for the six month period ended June 30, 2014 through the option to sale our trade receivables under the Receivables Agreement. For more information on the Receivables Agreement, refer to the discussion above Item 2. *Liquidity and Capital Resources—Sale of Accounts Receivable*;

- The change in accrued receivables from December 31, 2012 to June 30, 2013 was primarily the result of lower production of natural gas and NGLs from our facilities during the six month period ended June 30, 2013. We sold \$133.5 million of our accrued receivables under our Receivables Agreement. The decrease in accrued receivables from December 31, 2013 to June 30, 2014 was primarily due to lower prices and volumes of NGLs at our trucking and NGL marking business, partially offset by higher prices and volumes of natural gas and condensate for a net decrease of \$41.8 million. In addition, we sold \$16.2 million more receivables than we incurred for the six month period ended June 30, 2014 through the option to sale our accrued receivables under the Receivables Agreement. For more information on the Receivables Agreement, refer to the discussion above Item 2. *Liquidity and Capital Resources—Sale of Accounts Receivable*; and
- The decline in accrued purchases from December 31, 2012 to June 30, 2013 was primarily the result of lower production of NGLs from our facilities during the month of June 2013 as compared with December 2012 due to some producers electing to retain ethane in the gas stream rather than to extract it.

The above decrease was partially offset by an increase in net income of \$212.2 million offset by a \$101.1 million decrease in our non-cash items for the six month period ended June 30, 2014 compared to the six month period ended June 30, 2013. The decrease in non-cash items primarily consisted of the following:

- Decreased environmental costs of \$141.7 million mainly attributed to \$175.0 million in additional estimated costs recognized during 2013 related to the Line 6B crude oil release as a result of the Order accessed by the EPA in March 2013, while only \$33.0 million in additional estimated costs were recognized in six month period ended June 30, 2013;
- Increased derivative net losses of \$47.0 million, compared to derivative net gains in 2013, primarily as a result of fluctuations in commodity prices;
- Increased depreciation and amortization of \$29.2 million due to projects placed in service in 2013;
- Increased allowance for equity used during construction, or AEDC, of \$17.4 million mainly due to the Eastern Access Projects; and
- Decreased deferred and state income taxes for the three and six month periods ended June 30, 2014, of \$11.9 million and \$5.6 million, primarily due to the new Texas Margin Tax law passed in the second quarter of 2013 and an uncertain tax benefit adjustment for the 2012 tax year recorded in 2013, respectively.

Investing Activities

Net cash used in our investing activities during the six month period ended June 30, 2014 increased by \$293.2 million, compared to the same period of 2013, primarily due to increased additions to property, plant and equipment, net of construction payables in 2014 related to various enhancement projects of \$449.3 million, offset by the following:

- Decreased restricted cash balance of \$39.5 million consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary in accordance with the Receivables Agreement. For more information, refer to discussion above, Item 7. *Liquidity and Capital Resources—Sale of Accounts Receivable*; and

- Decreased cash contributions of $98.6 million combined with decreased allowance for interest during construction associated with our joint venture project, Texas Express NGL system, as the project went into service at the end of 2013, offset by $17.7 million in distributions in excess of cumulative earnings from our joint venture investment in the Texas Express NGL system.

Financing Activities

Net cash provided by our financing activities increased $796.8 million for the six month period ended June 30, 2014, compared to the same period in 2013, primarily due to the following:

- Increased net borrowings on our commercial paper of $1,489.7 million for the six months ended June 30, 2014;
- Increased capital contributions from noncontrolling interest in 2014 for ownership interests in the Mainline Expansion Projects, Eastern Access Projects and Sandpiper Project of $463.2 million;
- Decreased repayments on long-term debt of $200.0 million for 2014, due to us repaying in full our 4.750% Senior Notes due in 2013 compared to no payments on our Senior Notes in 2014; and
- Increased net borrowings on MEP's Credit Agreement of $140.0 million in 2014 compared to no activity in 2013.

Offsetting the increases above were the following:

- Decreased net proceeds in 2014 of $1,200.0 million due to no preferred unit issuances in 2014 while we had a preferred unit issuance in 2013 where we received $1,200.0 million in proceeds;
- Decreased net proceeds from unit issuances, including our General Partner's contributions of $278.7 million from 2013 while we had no issuances in 2014; and
- Increased distributions to our limited partners of $3.6 million and distributions to noncontrolling interest of $13.8 million.

SUBSEQUENT EVENTS

364-Day Credit Facility

On July 3, 2014, we amended our 364-Day Credit Facility to extend the revolving credit termination date to July 3, 2015, and to decrease aggregate commitments under the facility by $550.0 million. After these changes, our 364-day Credit Facility now provides to us aggregate lending commitments of $650.0 million.

Equity Restructuring Transaction

Effective July 1, 2014, the General Partner entered into an equity restructuring transaction, or Equity Restructuring, with the Partnership in which the General Partner irrevocably waived its right to receive cash distributions and allocations of items of income, gain, deduction and loss in excess of 2% in respect of its general partner interest in the Previous IDRs, in exchange for the issuance to a wholly-owned subsidiary of the General Partner of (i) 66.1 million units of a new class of Partnership units designated as Class D Units, and (ii) 1,000 units of a new class of Partnership units designated as Incentive Distribution Units. The irrevocable waiver is effective with respect to the calendar quarter ending on June 30, 2014, and each calendar quarter thereafter. See Note 2. *Net Income Per Limited Partner Unit.*

In connection with the Equity Restructuring, effective July 1, 2014, we amended and restated our partnership agreement. The amendments among other changes and in conjunction with the waiver described above, effectively modified the distribution rights provided for by our partnership agreement to waive the Previous IDRs and to provide distribution rights to the new Class D Units and Incentive Distribution Units.

These changes are discussed more fully in our Form 8-A/A filed with the SEC on July 1, 2014. Also, as part of the amendment to our partnership agreement, certain amendments were made to increase the Partnership's flexibility to maintain and increase interim distributions to unitholders until current and future growth investments by the Partnership begin to generate cash and to enhance the Partnership's ability to execute its long-term growth plans in a capital efficient and accretive manner.

Midcoast Energy Partners, L.P.

On June 18, 2014, we agreed to sell a 12.6% limited partner interest in Midcoast Operating to MEP, for $350.0 million in cash, which will bring EEP's total ownership interest in Midcoast Operating to 48.4%. This transaction closed on July 1, 2014, and represents EEP's first disposition of additional interests in Midcoast Operating since MEP's initial public offering on November 13, 2013. See Note 7. *Partner's Capital*

Distribution to Partners

On July 31, 2014, the board of directors of Enbridge Management declared a distribution payable to our partners on August 14, 2014. The distribution will be paid to unitholders of record as of August 7, 2014 of our available cash of $224.7 million at June 30, 2014, or $0.5550 per limited partner unit. Of this distribution, $187.3 million will be paid in cash, $36.7 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.8 million will be retained from our General Partner from amounts otherwise distributable to it in respect of its general partner interest and limited partner interest to maintain its 2% general partner interest.

Distribution to Series AC Interests

On July 31, 2014, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series AC interests, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $14.8 million to the noncontrolling interest in the Series AC, while $7.4 million will be paid to us.

Distribution to Series EA Interests

On July 31, 2014, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series EA interests, declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP will pay $16.7 million to the noncontrolling interest in the Series EA, while $5.6 million will be paid to us.

Distribution from MEP

On July 31, 2014, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable to their partners on August 14, 2014. The distribution will be paid to unitholders of record as of August 7, 2014, of MEP's available cash of $15.0 million at June 30, 2014, or $0.3250 per limited partner unit. MEP will pay $6.9 million to their public Class A common unitholders, while $8.1 million in the aggregate will be paid to us with respect to our Class A common units, subordinated units and to Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On July 31, 2014, the general partner of Midcoast Operating, acting in its capacity as the general partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of August 7, 2014. Midcoast Operating will pay $22.0 million to us and $23.5 million to MEP.

REGULATORY MATTERS

FERC Transportation Tariffs

Lakehead System

Effective April 1, 2013, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2013 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. This tariff rate adjustment filing also included the recovery of costs related to the Flanagan Tank Replacement Project and the Eastern Access Phase 1 Mainline Expansion Project. The Lakehead system utilizes the System Expansion Project II and the Facility Surcharge Mechanism, or FSM, which are components of our Lakehead system's overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

This tariff filing increased the transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.28 per barrel, to approximately $2.13 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

On June 27, 2014, we filed for an increase to our Lakehead system rates. These rates have an effective date of August 1, 2014. This tariff filing was in part an index filing in accordance with 18 C.F.R.342.3 and in part a compliance filing with certain settlement agreements, which are not subject to FERC indexing. This filing included the increase in rates in compliance with the indexed rate ceilings allowed by the FERC which incorporates the multiplier of 1.038858, which was issued by the FERC on May 14, 2014, in Docket No. RM93-11-000. This filing also reflected our annual tariff rate adjustment for the FSM components or our Lakehead systems' overall rate structure, as described above. As part of this rate structure our rates reflect our projected costs for 2014 and true-ups for the difference between estimated and actual costs for the prior year. Historically, we have made the Lakehead system annual tariff rate adjustment for the FSM component of rates with an effective date of April 1 and the index rate filing with an effective date of July 1, however, the filings were delayed as we were in negotiations with the Canadian Association of Petroleum Producers, or CAPP, concerning certain components of the tariff rate structure. This negotiation eliminates the SEPII surcharge and added to the FSM component of rates recovery of costs for Line 14, which is virtually the entire asset base associated with the SEPII expansion. The recent negotiation also provides for the recovery of Agreed-Upon Legacy Integrity and Agreed-Upon Future Integrity. These elements are a portion of the costs incurred by the partnership to maintain the integrity and safety of the pipeline systems. The rates also include recovery of costs related to Eastern Access Phase 2 Mainline Expansion and the 2014 Mainline Expansions.

This tariff filing increased the transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.32 per barrel, to approximately $2.49 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

*North Dakota and Ozark System*s

Effective April 1, 2013 for the North Dakota system we filed updates to the calculation of the surcharges on the two previously approve expansion, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. These expansions are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. This filing increased the average transportation rate for crude oil movements on our North Dakota System by $0.55 per barrel, to an average of approximately $2.06 per barrel.

Effective July 1, 2013, we filed FERC tariffs for our ,North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by FERC which incorporates the multiplier of 1.045923, which was issued by FERC on May 15, 2013, in Docket No. RM93-11-000.

Effective April 1, 2014, we filed updates to the calculation of the surcharges on the two previously approved expansions, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. As previously mentioned these expansions are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing increased transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.09 per barrel, to an average of approximately $2.21 per barrel.

On May 30, 2014, we filed FERC tariffs with effective dates of July 1, 2014 for our North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by the FERC which incorporates the multiplier of 1.038858, which was issued by the FERC on May 14, 2014, in Docket No. RM93-11-000.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the year ended December 31, 2013, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility of our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Interest Rate Derivatives

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional amounts and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at June 30, 2014.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate (1)	Fair Value (2) at June 30, 2014	Fair Value (2) at December 31, 2013
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (3.6)	$ (6.8)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (14.4)	$ (13.8)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ 0.2	$ 3.3
Contracts settling prior to maturity					
2014—Pre-issuance Hedges (3)	Cash Flow Hedge	$1,850	4.27%	$(242.3)	$(132.7)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 25.6	$ 60.8

(1) Interest rate derivative contracts are based on the one-month or three-month London Interbank Offered Rate, or LIBOR.

(2) The fair value is determined from quoted market prices at June 30, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $3.4 million of gains at June 30, 2014 and $7.1 million of losses at December 31, 2013.

(3) Includes $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013, respectively.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at June 30, 2014 and December 31, 2013.

	At June 30, 2014						At December 31, 2013	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	832,732	$ 4.41	$ 4.36	$ 0.1	$—	$—	$ —
	NGL	316,000	$ 62.97	$ 60.27	$ 0.9	$—	$ 0.6	$ (0.4)
Receive fixed/pay variable	Natural Gas	3,631,800	$ 4.32	$ 4.42	$ 0.3	$(0.7)	$ 0.1	$ (1.0)
	NGL	1,612,280	$ 54.87	$ 58.63	$ 1.0	$(7.1)	$ 4.8	$(12.7)
	Crude Oil	725,528	$ 94.78	$103.18	$—	$(6.1)	$ 3.4	$ (5.4)
Receive variable/pay variable	Natural Gas	32,675,300	$ 4.37	$ 4.38	$ 0.7	$(1.1)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	79,594	$ 4.36	$ 4.36	$—	$—	$—	$ —
	NGL	1,355,000	$ 35.27	$ 34.13	$ 1.6	$(0.1)	$ 0.9	$ (0.9)
	Crude Oil	81,000	$105.17	$107.05	$—	$(0.1)	$—	$ —
Receive fixed/pay variable	Natural Gas	333,893	$ 4.41	$ 4.40	$—	$—	$—	$ —
	NGL	2,403,278	$ 37.70	$ 38.51	$ 0.5	$(2.5)	$ 0.4	$ (2.6)
	Crude Oil	184,000	$103.96	$104.85	$ 0.2	$(0.3)	$—	$ (0.4)
Pay fixed	Power (4)	29,510	$ 39.57	$ 46.58	$—	$(0.2)	$—	$ (0.7)
Receive variable/pay variable	Natural Gas	107,169,373	$ 4.41	$ 4.40	$ 1.3	$(0.8)	$ 0.9	$ (0.4)
	NGL	13,859,812	$ 48.43	$ 48.03	$ 6.4	$(0.8)	$ 5.8	$ (3.7)
	Crude Oil	734,242	$101.94	$104.89	$ 0.8	$(2.9)	$ 1.1	$ (1.2)
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	19,080	$ 4.47	$ 4.54	$—	$—	$—	$ —
	NGL	82,500	$ 83.98	$ 84.84	$—	$(0.1)	$—	$ —
	Crude Oil	456,000	$ 96.90	$ 92.94	$ 1.8	$—	$—	$ —
Receive fixed/pay variable	Natural Gas	596,861	$ 4.74	$ 4.51	$ 0.1	$—	$—	$ —
	NGL	755,000	$ 53.11	$ 54.33	$ 0.9	$(1.8)	$ 1.5	$ (1.1)
	Crude Oil	959,665	$ 97.20	$ 97.13	$ 2.4	$(2.4)	$ 8.3	$ —
Receive variable/pay variable	Natural Gas	19,885,000	$ 4.29	$ 4.31	$ 0.3	$(0.7)	$ 0.1	$ —
Physical Contracts								
Receive fixed/pay variable	NGL	295,624	$ 53.31	$ 54.03	$ 0.1	$(0.3)	$—	$ —
Receive variable/pay variable	Natural Gas	79,446,592	$ 4.29	$ 4.29	$ 1.3	$(0.8)	$ 0.5	$ (0.1)
	NGL	2,977,353	$ 66.95	$ 66.50	$ 1.9	$(0.5)	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	—	$ —	$ —	$—	$—	$ 0.7	$ —
Receive variable/pay fixed	Crude Oil	68,250	$ 92.49	$ 90.00	$ 0.2	$—	$—	$ —
Receive variable/pay variable	Natural Gas	5,927,000	$ 4.09	$ 4.11	$—	$(0.1)	$—	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	32,721,379	$ 4.16	$ 4.16	$ 0.7	$(0.6)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	13,399,743	$ 4.38	$ 4.36	$ 0.2	$(0.1)	$—	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl. Our power purchase agreements are measured in MWh.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas, $/Bbl for NGL and crude oil and $/MWh for power.

(3) The fair value is determined based on quoted market prices at June 30, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses and $0.1 million of gains at June 30, 2014 and December 31, 2013, respectively.

(4) For physical power, the receive price shown represents the index price used for valuation purposes.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at June 30, 2014 and December 31, 2013.

	At June 30, 2014						At December 31, 2013	
					Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Strike Price (2)	Market Price (2)	Asset	Liability	Asset	Liability
					(in millions)			
Portion of option contracts maturing in 2014								
Puts (purchased)	Natural Gas	2,208,000	$ 3.90	$ 4.46	$ 0.1	$—	$ 0.7	$—
	NGL	386,400	$54.79	$56.17	$ 1.3	$—	$ 2.9	$—
Calls (written)	NGL	230,000	$60.92	$58.65	$—	$(0.6)	$—	$(1.0)
Puts (written)	Natural Gas	1,472,000	$ 3.90	$ 4.46	$—	$(0.1)	$—	$(0.5)
Calls (purchased)	NGL	46,000	$50.40	$45.50	$ 0.1	$—	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.22	$ 1.0	$—	$ 1.7	$—
	NGL	1,259,250	$49.40	$54.10	$ 4.3	$—	$ 6.0	$—
	Crude Oil	547,500	$85.42	$96.40	$ 1.2	$—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.22	$—	$(0.2)	$—	$(0.3)
	NGL	438,000	$57.05	$54.83	$—	$(2.1)	$—	$(1.0)
	Crude Oil	547,500	$91.75	$96.40	$—	$(4.9)	$—	$(1.9)
Puts (written)	Natural Gas	1,825,000	$ 4.08	$ 4.22	$—	$(0.6)	$—	$—
Calls (purchased)	Natural Gas	1,277,500	$ 5.05	$ 4.22	$ 0.2	$—	$—	$—
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 4.24	$ 0.4	$—	$—	$—
	NGL	366,000	$38.22	$43.67	$ 1.3	$—	$—	$—
	Crude Oil	439,200	$80.00	$91.25	$ 1.5	$—	$—	$—
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 4.24	$—	$(0.3)	$—	$—
	NGL	366,000	$47.02	$43.67	$—	$(1.8)	$—	$—
	Crude Oil	439,200	$92.25	$91.25	$—	$(3.4)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.
(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.
(3) The fair value is determined based on quoted market prices at June 30, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of gains at June 30, 2014.

Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

	June 30, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality (1)		
AAA	$ 0.2	$ 0.3
AA	(97.5)	(49.7)
A (2)	(145.9)	(40.1)
Lower than A	3.2	0.8
	$(240.0)	$(88.7)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $3.3 million and $16.7 million of cash collateral at June 30, 2014 and December 31, 2013, respectively.

Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, or the Exchange Act, within the time periods specified in the rules and forms of the Securities and Exchange Commission, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2014. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

There have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three month period ended June 30, 2014.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, "Note 9. *Commitments and Contingencies*," which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Item 6. Exhibits

Reference is made to the "Index of Exhibits" following the signature page, which we hereby incorporate into this Item.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Enbridge Energy Partners, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.
as delegate of Enbridge Energy Company, Inc.
as General Partner

Date: August 1, 2014

By: /s/ Mark A. Maki
Mark A. Maki
President and
Principal Executive Officer

Date: August 1, 2014

By: /s/ Stephen J. Neyland
Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)

Index of Exhibits

Each exhibit identified below is filed as a part of this Quarterly Report on Form 10-Q. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated.

Exhibit Number	Description
3.1	Sixth Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P., dated as of June 18, 2014 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K, filed on June 19, 2014).
10.1	Irrevocable Waiver dated as of June 18, 2014, made by Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on June 19, 2014).
10.2	Purchase and Sale Agreement by and between Enbridge Energy Partners, L.P. and Midcoast Energy Partners, L.P., dated as of June 18, 2014 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K, filed on July 19, 2014).
10.3	Amendment No. 5 to Credit Agreement and Extension and Decrease Agreement, dated as of July 3, 2014, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on July 8, 2014).
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Maki, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Enbridge Energy Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2014

By: /s/ Mark A. Maki

Mark A. Maki
President and Principal Executive Officer
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. Neyland, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Enbridge Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2014

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)

Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

The undersigned, being the Principal Executive Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014 (the "Quarterly Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: August 1, 2014

By: /s/ Mark A. Maki

Mark A. Maki
President and Principal Executive Officer
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)

Exhibit 32.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

The undersigned, being the Principal Financial Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014 (the "Quarterly Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: August 1, 2014

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

JULY 30 2012

1200 New Jersey Avenue, SE
Washington, D.C. 20590

<u>VIA CERTIFIED MAIL AND FAX TO: 832-325-5473</u>

Mr. Richard Adams
Vice President, US Operations
Enbridge Energy, LP
City Center Office
1409 Hammond Avenue
Superior, WI 54880-5247

Re: CPF No. 3-2012-5017H

Dear Mr. Adams:

Enclosed is a Corrective Action Order issued in the above-referenced case. It finds that operation of the 24-inch diameter Line 14 would be hazardous to life, property, and the environment without immediate corrective action. The Corrective Action Order requires you to take certain corrective actions to protect the public, property, and the environment in connection with the failure of Line 14 that occurred on July 27, 2012, near Grand Marsh, Wisconsin. Service is being made by certified mail and facsimile. Your receipt of this Corrective Action Order constitutes service of that document under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon receipt.

We look forward to the successful resolution of the concerns arising out of this failure in a manner that will ensure the safe operation of the pipeline. Please direct any questions on this matter to David Barrett, Director, Central Region, OPS, at [redacted]

[redacted]
Associate Administrator
for Pipeline Safety

Enclosure: Corrective Action Order and Copy of 49 C.F.R. §190.233

cc: Mr. Alan Mayberry, Deputy Associate Administrator for Field Operations, OPS
Mr. David Barrett, Director, Central Region, OPS
Mr. Mark Maki, President, Enbridge Energy Management, LLC
Mr. Steve Wuori, President, Liquids Pipelines, Enbridge Pipelines Inc.

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
	)	
Enhridge Energy, LP,	)	**CPF No. 3-2012-5017H**
	)	
Respondent.	)	

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order (Order) is being issued, under authority of 49 U.S.C. § 60112, to Enbridge Energy, LP (Enbridge or Respondent), the operator of the 24-inch diameter hazardous liquid pipeline designated as Line 14 that runs from Respondent's Superior Terminal and pump station in Superior, Wisconsin, to its Mokena delivery facility in Mokena, Illinois (Affected Pipeline). This Order finds that continued operation of the pipeline without corrective action would be hazardous to life, property, or the environment and requires Respondent to take immediate corrective action to ensure the safe operation of the pipeline.

On July 27, 2012, Respondent experienced a failure on the Affected Pipeline near Grand Marsh, WI (Failure), in Adams County. Respondent estimates the volume of product spilled to be approximately 1,200 barrels of crude oil.

Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), initiated an investigation of the Failure. OPS has determined that the release originated from the Affected Pipeline but the cause of the Failure has not yet been determined. The preliminary findings of the investigation are as follows:

Preliminary Findings

- The Affected Pipeline originates at the Superior Terminal in Wisconsin, proceeds southeast for approximately 467 miles, and terminates at the Mokena delivery facility near Chicago, Illinois.

- At approximately 2:41 pm CDT on July 27, 2012, Respondent's control center staff noted indications of a release on the Affected Pipeline. Respondent initiated shut down of the pipeline and notified field personnel in Wisconsin at 3:00 pm CDT.

- At approximately 2:45 pm CDT on July 27, 2012, Respondent received a call from a landowner who reported that crude oil was spraying on the pipeline right-of-way. The local sheriff's office also called the control center at 2:50 pm CDT.

- At approximately 2:55 pm CDT on July 27, 2012, Respondent isolated the failed pipe section by closing remotely controlled valves located upstream and downstream of the Failure site.

- At 3:27 pm CDT on July 27, 2012, Respondent's field personnel confirmed the location of the Failure as being approximately 5.7 miles east of Grand Marsh, Wisconsin, at 2487 County Road G in Adams County. The Failure site was located at milepost (M.P.) 232 on the Affected Pipeline.

- At 5:16 pm CDT on July 27, 2012, Respondent notified the National Response Center of the discharge of crude oil (NRC Report No. 1019189). Respondent reported 1,200 barrels of crude oil were released.

- Two households were evacuated due to their proximity to the Failure site. Several cattle and horses required veterinary attention. No further injuries cahave been reported.

- The Affected Pipeline crosses multiple rivers, including a navigable waterway, i.e., the Illinois River in the Chicago area, and intersects multiple High Consequence Areas (HCAs), including drinking water sources, "Other Populated Areas," "High Population Areas," and ecological resources. The Affected Pipeline also crosses numerous state highways in Wisconsin and Illinois, and multiple interstate highways before terminating at Mokena, Illinois.

- The Failure site is 2.5 miles away from a drinking water source, which so far shows no signs of contamination.

- The Affected Pipeline was constructed in 1998 of 24-inch, API 5L grade X70, high frequency electric resistance welded (ERW) pipe manufactured by the Stupp Pipe Corporation, with wall thicknesses ranging from 0.328-inch to 0.500-inch. The pipe at the Failure site has a 0.328-inch nominal wall thickness. The Affected Pipeline has a fusion bonded epoxy coating and an impressed-current cathodic protection system.

- Just prior to the time of the Failure, the discharge pressure at the Adams pump station (M.P. 227.4), located approximately 4.6 miles upstream of the Failure site, was 1,329 psig. The established maximum operating pressure (MOP) of the pipeline is 1,378 psig.

- Respondent performed a hydrostatic test of the pipeline in 1998 from M.P. 227.49 to M.P. 253.15 to a test pressure of 1,875 psig, which included the Failure site.

- The cause of the Failure is unknown but PHMSA has is continuing an onsite investigation. PHMSA investigators observed a 4.18-foot-long split in the high frequency ERW seam of the pipe with a maximum opening of 6.25 inches. The pipeline currently remains out of service.

- During construction of the Affected Pipeline in 1998, radiography of girth welds revealed lack-of-fusion defects in the ERW seams at multiple locations along the Affected Pipeline.

- On January 1, 2007, a rupture of the Affected Pipeline occurred in Atwood, Wisconsin, releasing 1,500 barrels of crude oil. The rupture was located at M.P. 149.4, approximately one mile downstream of Respondent's Owen pump station in Clark County, Wisconsin. The OPS investigation of the 2007 failure found that a pre-existing lack-of-fusion defect in the ERW seam had grown to failure by a fatigue mechanism due to cyclic loads and that the chemical and mechanical properties of the pipe joint fracture surface also had indications of low toughness of the ERW seam.

- Following the January 1, 2007 failure, Respondent utilized ultrasonic crack detection technology to assess the Affected Pipeline. Multiple crack anomalies associated with the ERW seam were reported by the inline inspection (ILI) vendor. Based on the ILI results, Respondent made repairs to the Affected Pipeline for a 1.25 x MOP factor of safety. Calculations performed by Respondent in 2008 predicted that Line 14 would not fail for a minimum of 10 years based on a crack growth analysis that considered the operating pressure spectrum.

- Respondent performed an ILI of the Affected Pipeline in the area of the Failure in 2011 utilizing high-resolution geometry and magnetic flux leakage (MFL) tools. An ultrasonic crack detection technology ILI inspection was scheduled to be performed in the area of the failure in August 2012.

- The history of failures on Respondent's Lakehead Pipeline system, of which the Affected Pipeline is a part, the defects originally discovered during construction, and the 2007 failure indicate that Respondent's integrity management program may be inadequate.

Determination of Necessity for Corrective Action Order and Right to Hearing

Under 49 U.S.C. § 60112 and 49 C.F.R. § 190.233, the Associate Administrator for Pipeline Safety (Associate Administrator) may issue a corrective action order after providing reasonable notice and the opportunity for a hearing if he finds that a particular pipeline facility is or would be hazardous to life, property, or the environment. The terms of such an order may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or any other action as appropriate. The Associate Administrator may also issue a corrective action order without providing any notice or the opportunity for a hearing if he finds that a failure to do so expeditiously will result in likely serious harm to life, property or the environment. The opportunity for a hearing will be provided as soon as practicable after the issuance of the CAO in such cases.

After evaluating the foregoing preliminary findings of fact, I find that the continued operation of the pipeline without corrective measures would be hazardous to life, property and the environment. Additionally, after considering the age and failure history of the pipe, the circumstances surrounding the Failure, the proximity of the pipeline to populated areas, water bodies, drinking water resources, public roadways, and High Consequence Areas, the hazardous nature of the product being transported, 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 likely result in serious harm to life, property, and the environment. Accordingly, this Corrective Action Order is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by fax at (202) 366-4566. The hearing will be held in Kansas City, Missouri, or Washington, DC, on a date that is mutually convenient to PHMSA and Respondent.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken. Respondent will be notified of any additional measures required and amendment of this Order will be considered. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Action

Pursuant to 49 U.S.C. § 60112, Enbridge Energy, LP, is ordered to immediately take the following corrective actions to ensure the safe operation of the Affected Pipeline:

1. Develop and submit a written re-start plan for prior approval of the Director, Central Region, OPS (Director). Obtain written approval from the Director prior to resuming operation of the Affected Pipeline. Submit the written plan to the Director at the Pipeline and Hazardous Materials Safety Administration, 901 Locust Street, Suite 462, Kansas City, MO 64106-2641. The plan must provide for adequate patrolling of the Affected Pipeline during the restart process to ensure the prompt detection of leaks, include a daylight restart, and detail advance communications with local emergency response officials.

2. After receiving approval from the Director to restart, maintain a minimum twenty percent (20%) pressure reduction in the operating pressure of the Affected Pipeline. Submit the operating pressures for each pump station on the Affected Pipeline at the time of failure and the reduced discharge pressure limits for approval by the Director in the restart plan referenced in Item 1. The reduced discharge pressure limits must also consider any ILI features and anomalies that are present in the Affected Pipeline to provide for continued safe operation while further corrective actions are completed. The approved pressure restrictions will remain in effect until written approval to increase the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director pursuant to

Item 12. Respondent must maintain documentation to show that these requirements have been met.

Review the pressure restrictions monthly, taking into account any ILI features present in the pipeline and analysis of operating pressure cycle data. Based on the monthly review, Enbridge must immediately reduce operating pressure accordingly to maintain safe operations. Submit results of the monthly review, the current discharge set points, including any additional reductions, and any exceedance of discharge set points, in the reports pursuant to Item 10.

3. Within 45 days of receipt of this Order, complete mechanical and metallurgical testing and failure analysis of the failed pipe and other pipe removed, including analysis of soil samples and any foreign materials. Complete the testing and analysis as follows:

   A. Document the chain-of-custody when handling and transporting the failed pipe section and other evidence from the failure site;

   B. Submit the testing protocols and the selection of the testing laboratory to the Director for prior approval.

   C. Prior to commencing the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow a PHMSA representative to witness the testing; and

   D. Ensure that the testing laboratory distributes all resulting reports in their entirety (including all media), whether draft or final, to the Director at the same time as they are made available to Respondent.

4. Within 30 days of receipt of this Order, conduct an evaluation of the previous inline inspection (ILI) results, including a review and reporting by the ILI vendors' analysts (including raw data) of the Affected Pipeline as follows:

   A. Submit any and all reports from the 2007 ILI runs as received from the vendors;

   B. Re-evaluate the 2007 inline inspection results to determine whether any features were present in the failed pipe joint and other pipe removed. Determine if any features with similar characteristics are present elsewhere on the Affected Pipeline. Submit to the Director the scheduled dates, times, and locations of meetings with the ILI vendors to allow PHMSA representatives to attend;

   C. Submit a report describing the ILI features present in the failed joint and other pipe removed, the process used to re-evaluate ILI results, and the results of the re-evaluation including characterization of the size and location of similar features on the Affected Pipeline.

5. As recommended in PHMSA Advisory Bulletin 2012–06, verify the records for the Affected Pipeline relating to operating specifications for maximum operating pressure

(MOP). Within 45 days of receipt of this Order, submit a report on this record verification and copies of these records to the Director.

6. Within 90 days following receipt of this Order, complete an evaluation utilizing multiple root cause failure analysis techniques, including a Management Oversight and Risk Tree (MORT) analysis, to determine the underlying causes and contributing factors to the Failure, including preventive measures employed by Enbridge. Within 10 days of receipt of this Order, submit a list of proposed independent third-party contractors for prior approval by the Director, along with contractor qualifications and scope of work. The scope of the evaluation must include, but not be limited to: Enbridge's procedures; failure, operating and maintenance history; use of safety factors; review of ILI results; application of assessment methods, analysis and monitoring of pressure cycles in determining assessment intervals and operating pressures; decision processes regarding repair methods, including pipe replacement; a detailed review of the adequacy of the operator's spill prevention plans; and a detailed review of all emergency response activities, including initial controller response. All reports in their entirety (including all media), whether draft or final, shall be submitted to the Director at the same time they are made available to Respondent. Submit the final report for the Director's approval.

7. Within 90 days following receipt of this Order, submit an integrity verification and remedial work plan (Work Plan) for implementing continuing long-term periodic testing to the Director for approval. The Work Plan must provide for the verification of the integrity of the pipeline and must address all factors known or suspected in the July 27, 2012 failure, including, but not limited to the following:

    A. The integration of the results of the failure analyses and other actions required by this Order, with all relevant operating data, including all historical repair information, construction, operating, maintenance, testing, metallurgical analysis or other third-party consultation information, and assessment data for the Affected Pipeline. Data gathering activities must include a review of the failure history of the pipeline (including in-service and pressure test failures) and development of a written report to be approved by the Director containing all available information regarding locations, dates, and causes of leaks and failures;

    B. The performance of additional field testing, inspections, and evaluations to determine whether and to what extent the conditions associated with the failures, or any other integrity-threatening conditions are present elsewhere on the Affected Pipeline. At a minimum, the inspections and evaluations must consider use of in-line inspection that can reliably detect and identify anomalies. Include a detailed description of the criteria to be used for the evaluation and prioritization of any integrity threats and anomalies that are identified (accounting for uncertainties in anomaly and defect sizing by the ILI vendor and field non-destructive examination), establishing a minimum 1.39 x MOP factor of safety upon completion of testing, inspections, evaluations, replacements and repairs as described in this Order;

C. The performance of repairs or other corrective measures that fully remediate the conditions associated with the pipeline failures and any other integrity-threatening condition everywhere along the Affected Pipeline. The plans must be based on the known history and condition of the pipeline, and must be scheduled to be completed as follows: (1) repairs must be completed within 6 months of receipt of the ILI vendor's final report; (2) confirmatory hydrostatic pressure testing of the Affected Pipeline by December 31, 2013; and (3) replacement of the Affected Pipeline or portions thereof by July 31, 2015. Include a detailed description of the criteria and methods to be used in undertaking any repairs, replacements, or other remedial actions to establish a minimum 1.39 x MOP factor of safety.

8. The approved Work Plan will be incorporated into this Order. Respondent must revise the Work Plan as necessary to incorporate the results of actions undertaken pursuant to this Order and whenever necessary to incorporate new information obtained during the failure investigation and remedial activities. Submit any such plan revisions to the Director for prior approval. The Director may approve plan elements incrementally.

9. Implement the Work Plan as it is approved by the Director, including any revisions to the plan.

10. Submit monthly reports to the Director that: (1) include all available data and results of the testing and evaluations required by this Order; and (2) describe the progress of the repairs or other remedial actions being undertaken. The first monthly report for the period from August 1 through August 31, 2012 shall be due by September 7, 2012.

11. It is requested that Respondent maintain documentation of the costs associated with implementation of this Corrective Action Order. Include in each monthly report submitted, the to-date total costs associated with: (1) preparation and revision of procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

12. The Director may allow the removal or modification of the pressure restriction set forth in Item 2 upon a written request from Respondent demonstrating that the hazard has been abated and that restoring the pipeline to its pre-failure operating pressure is justified based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies and operating parameters of the pipeline.

The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted demonstrating good cause for an extension.

With respect to each submission that under this Order requires the approval of the Director, the Director may: (a) approve, in whole or part, the submission; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove in whole or in part, the submission, directing that Respondent modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Respondent must take all actions required by the submission as approved or modified by the Director. If the Director disapproves all or any portion of the submission, Respondent must correct all deficiencies within the time specified by the Director, and resubmit it for approval. If a resubmitted item is disapproved in whole or in part, the Director may again require Respondent to correct the deficiencies in accordance with the foregoing procedure, and the Director may otherwise proceed to enforce the terms of this Order.

Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), you must provide, along with the complete original document, a second copy of the document with those portions you believe qualify for confidential treatment redacted, along with an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

In your correspondence on this matter, please refer to "CPF No. 3-2012-5017H" and for each document you submit, please provide a copy in electronic format whenever possible. The actions required by this Corrective Action Order are in addition to and do not waive any requirements that apply to Respondent's pipeline system under 49 C.F.R. Part 195, under any other order issued to Respondent under authority of 49 U.S.C. § 60101 et seq., or under any other provision of Federal or State law.

Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

The terms and conditions of this Corrective Action Order are effective upon receipt.

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

7/30/2012
Date Issued

Login(/user/login)

KINDER MORGAN (http://www.kindermorgan.com/)

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Press Releases(/press-releases/all/all/all)
Multimedia Gallery(/multimedia-gallery)
In the News (/news-stories)
Media Kit (/media-kit)

Safety & Environment(http://www.kindermorgan.com/pages/responsibility)
Fact Sheet(http://ir.kindermorgan.com/sites/kindermorgan.investorhq.businesswire.com/files/doc_library/file/Corporate_Fact_Sheet.pdf)
Presentations & Webcasts(/presentations-webcasts)
Annual & Quarterly Reports(/annual-quarterly-reports)
SEC Filings(/sec-filings)
Dividend History(/dividend-history)
Calendar(/events-calendar)
Corporate Governance(http://www.kindermorgan.com/about_us/kmi_corporate_governance.aspx)
Stock Quote(/stock-chart)
Request an Investor Kit(/investor-kit)
Investor FAQs(/investor-faqs)
Analyst Coverage(/analyst-coverage)
o-
statements)
Hiland Bond Holders(http://portal.kindermorgan.com/docs/Hiland/SitePages/Home.aspx)
com)
Reports(/archive/historical-annual-quarterly-reports)
History(/archive/distribution-dividend-history)
Releases(/archive/historical-press-releases)
KMI Acquisition of KMP, KMR & EPB(http://www.kindermorgan.com/pages/investor/kmi_transaction.aspx)
KMR Form 8937(/report/form-kmr-8937/kmr-form-8937)

Enbridge, TransCanada, Kinder Morgan working together to evaluate aerial-based pipeline safety technologies

Tuesday, April 28, 2015 3:44 pm EDT

"We are committed to identify, develop and test new technologies to further progress key areas of pipeline safety, such as leak detection. Through collaboration with committed industry partners, we continue to make important advancements with leak detection technology"

Three North American pipeline industry leaders – Enbridge Pipelines Inc., TransCanada Corporation, and Kinder Morgan Canada – have signed a Joint Industry Partnership (JIP) agreement to conduct research into aerial-based leak detection technologies, in the interest of enhancing across-the-board pipeline safety.

This partnership illustrates a spirit of collaboration among TransCanada, Kinder Morgan and Enbridge in the continued common pursuit of industry-wide safety and operational excellence. It also demonstrates the partners' commitment to investing in the leading-edge tools and technologies that can bolster safety and reliability, while at the same time addressing public demands for responsible pipeline development.

The goal of the project is to identify technologies capable of viably detecting small leaks from liquid petroleum pipeline systems to improve pipeline safefy. The project is expected to involve laboratory research and field trials to evaluate the feasibility of commercially available aerial-based leak detection technologies, for use with crude oil and hydrocarbon liquids pipelines. The partnership includes a funding commitment from all three companies. Data analysis will be conducted by Alberta Innovates - Technology Futures, and testing will be carried out by project research partner C-FER Technologies (1999) Inc. of Edmonton.

A previous Joint Industry Partnership (JIP) – which was established by TransCanada and Enbridge, and now includes Kinder Morgan – has already yielded groundbreaking leak detection research using a state-of-the-art pipeline simulator known as the External Leak Detection Experimental Research (ELDER) test apparatus.

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We are committed to identify, develop and te t new technologies to further progress key areas of pipeline safety, such as leak detection. Through collaboration with committed industry partners, we continue to make important advancements with leak detection technology," says Kirk Byrtus, Enbridge's Vice President of Pipeline Control. "This extension to the Joint Industry Partnership is another great example of the pipeline indu try connecting to make important advancements with leak detection technology, and we look forward to closely working with our partners, TransCanada and Kinder Morgan."

"Pipelines are widely accepted as the safest and most efficient way to transport oil and gas, and TransCanada continues to strive for zero leaks or safety incidents on our pipelines," says Vern Meier, TransCanada's Vice President of Pipeline Safety and Compliance. "Joining forces with Kinder Morgan and Enbridge helps us maximize research potential and reach new levels of technological innovation to improve our industry as a whole."

"Kinder Morgan is pleased to be participating in this project as part of our systematic approach to leak detection, and our fundamental philosophy of continuous improvement and safe operations," says Dan Carter, Director of Central Region and Control Centre, Kinder Morgan Canada. "We look forward to working collaboratively with TransCanada, Enbridge, C-FER Technologies, and the participating vendors as part of this evaluation process."

Kinder Morgan, Enbridge, and TransCanada have each committed $200,000 to this partnership agreement. All three companies involved in this partnership agreement will share equally in the new knowledge and advancements that can be applied directly to improve safety and efficiency in their respective operations.

Potential technologies to be tested may include infrared camera-based systems, laser-based spectroscopy systems, and flame ionization detection systems, with sensors suitable for mounting on light aircraft or helicopters. Representatives of Enbridge and C-FER Technologies are currently surveying commercial vendors of these airborne leak detection technologies to validate their feasibility for liquid hydrocarbon pipelines. Project research and trials are expected to begin during the third quarter of 2015.

"The challenge with airborne leak detection systems is not with the aircraft, but with selecting appropriate sensors to detect liquid hydrocarbon leaks before they reach the surface," says Brian Wagg, Director of Business Development and Planning for C-FER Technologies.

"This program helps operating companies understand which technologies are best suited for detecting these leaks, and will provide vendors with unique information on what leaks actually look like. This information will help those vendors fine-tune their systems to detect leaks with greater reliability."

(https://www.youtube.com/channel/UCGodkFZt8Ca8Gb9DVtbigmQ)

Meanwhile, work on the ELDER leak detection project, originally announced in December 2013 by Enbridge and TransCanada, continues at C-FER Technologies' Edmonton research facility.

Enbridge and TransCanada have each committed $1.6-million to the ELDER project, while Kinder Morgan has committed $1-million. The project has a total funding commitment of more than $6-million.

Engineers from C-FER Technologies, Enbridge and TransCanada performed a series of tests throughout 2014 on four external leak detection technologie vapor en ing tubes, fiber-optic distributed temperature sensing (DTS) systems, hydrocarbon-sensing cables and fiber-optic distributed acoustic sensing (DAS) systems. All engineering and test data is shared among committed project partners.

Since 2013, the ELDER program has carried out four tests, and collected data from the 13 participating vendors, representing hundreds of recorded leaks in the ELDER apparatus. Data analysis is ongoing, but some participating vendors have already reviewed test results with the intention of using them to improve their systems. The ELDER program is expected to continue into 2016.

(NOTE TO MEDIA: Photos of aerial based leak-detection technologies at work are available upon request.)

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Fiber optics on the Flanagan South line

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Piping Up For Technology Series (Part 7)

Innovation never stands still [illegible] constantly testing commercially available technologies, and looking for opportunities to enhance existing technologies, in the areas of design, prevention, monitoring and leak detection, to keep our pipelines safe.

Our Piping Up For Technology Series, on the @enbridge blog, offers a glimpse of various research projects we're engaged in, and the efforts we're making to adapt and harness technology for safety's sake. These proactive investments in innovation are intended to add another layer of safety and security to our pipeline network – and, ultimately, to the energy transportation industry as a whole.

It's a groundbreaking research project, and it's now entered the soil of the Show-Me State.

Two years ago, Enbridge announced a joint industry partnership to begin using the External Leak Detection Experimental Research (ELDER) test apparatus, a tool designed by Enbridge to assess and validate external leak detection technologies on crude oil pipelines

After simulating pipeline products, soil characteristics, and other environmental factors with the large-scale ELDER tool, and gleaning some invaluable test results in an Edmonton laboratory, we've taken this project outside.

Specifically, central Missouri, where we've buried fiber optic cable alongside a 20-mile (32-kilometer) stretch of our newly built Flanagan South pipeline.

"Essentially, our testing of external leak detection systems is increasing to an even larger scale with this fiber optic pilot project in Missouri," says Cam Meyn, a supervisor of testing and research in Enbridge's Leak Detection department.

"ELDER gave us some great information in a controlled environment. Other factors, like longer-term system reliability and the effects of weather, are hard to simulate," adds Meyn. "This stage of the project will give us a more complete picture. It will allow us to test the capabilities of the system to detect leaks, while also providing us with the opportunity to explore the benefits related to damage prevention.

"The two stages of the process essentially fit hand-in-glove."

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Enbridge's fiber optic leak detection pilot project in Missouri is a $4-million endeavor, involving more than 30 Enbridge employees and contractors, with structured testing activities occurring until mid-2016.

Thanks to data collected from the ELDER project, we've shortlisted the number of third-party vendors involved, and we'll be testing both distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) systems at various locations along that 20-mile segment of the Flanagan South line.

With the help of a purpose built field leak simulator assembled by Lake Superior Consulting of Duluth, MN, we'll be using water, heat-trace and acoustic-based instrumentation in the soil to replicate leaks and test the systems' capabilities.

"We're looking for a leak detection system that can quickly and reliably identify very small leaks, and provide an accurate leak location," says Tania Rizwan, an Edmonton-based senior research engineer with Enbridge. "We hope to demonstrate its value in providing an incremental benefit to our other leak detection systems."

These systems, if proven effective through this pilot project, could provide enhanced leak detection in high-consequence areas along Enbridge's crude oil pipeline network, including areas of high urban population and environmentally sensitive areas. If broadly applied, the fiber optic infrastructure also has the potential to provide a communications backbone for SCADA (supervisory control and data acquisition) and other IT systems, as well as a means of incident prevention by detecting nearby excavation or unauthorized activity along the pipeline right-of-way.

The Flanagan South pipeline "is not a test lab. This is an operating asset, we have real-world expectations to which these systems must perform, and we will also be performing these tests with operational safety as priority No. 1," says Scott Medynski, a project manager with Enbridge.

"While it may take some time to see this technology fully tuned for real-world performance, we feel strongly about its potential to become an integral component of the leak detection system on Flanagan South."

Watch for upcoming posts from our Piping Up For Technology series on the @enbridge blog channel.

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Technical Review of Leak Detection Technologies

Volume I

Crude Oil Transmission Pipelines

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ACRONYM DEFINITIONS

ADEC	Alaska Department of Environmental Conservation
API	American Petroleum Institute
BAT	Best Available Technology
CFR	Code of Federal Regulations
CPM	Computational Pipeline Monitoring
DOT-OPS	U.S. Department of Transportation Office of Pipeline Safety
EPA	U.S. Environmental Protection Agency
LDS	Leak Detection System
MTU	Master Terminal Unit
PLC	Programmable Logic Controller
RTTM	Real Time Transient Modeling
RTU	Remote Terminal unit
SCADA	Supervisory Control and Data Acquisition

PREAMBLE

Analysis of recent data from the U.S. Department of Transportation Office of Pipeline Safety (DOT-OPS) indicates that, despite stricter regulations and enforcement, the rate at which pipeline accidents occurs has not significantly changed over the last two decades (Hovey and Farmer, 1999). The statistics suggest that short pipelines will have at least one reportable accident during a 20-year lifetime and longer pipelines (800 or more miles of line pipe) can expect a reportable incident every year.

Research indicates that the best opportunities to mitigate pipeline accidents and subsequent leaks are through prevention measures such as aggressive controller training and strict enforcement of safety and maintenance programs (Hovey and Farmer, 1999; Borener and Patterson, 1995). The next most productive enhancement comes from implementing better pipeline monitoring and leak detection equipment and practices. Early detection of a leak and, if possible, identification of the location using the best available technology allows time for safe shutdown and rapid dispatch of assessment and cleanup crews. An effective and appropriately implemented leak detection program can easily pay for itself through reduced spill volume and an increase in public confidence.

Recognizing the importance of leak detection in the prevention of oil spills and the need for a more thorough understanding of the use and effectiveness of leak detection technologies used by the Alaska oil industry, the Alaska Department of Environmental Conservation (ADEC) developed best available technology (BAT) regulations for inclusion in their spill prevention assessment program. ADEC issued a contract to identify, analyze, and report on technologies and systems that can be used to detect leaks in crude oil transmission pipelines to meet the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv). Identifying strengths and weaknesses in leak detection technologies will help the Industry Preparedness and Pipeline Program of ADEC make further improvements in preventing oil spills via strategic implementation of the BAT regulations.

Ideally leak detection vendors could state exactly how their systems would perform on a given pipeline configuration prior to installation. In practice, predicting performance is often difficult due to variability in product characteristics (density, viscosity), pipeline parameters (diameter, length, elevation profile), and process instrumentation variables (flow, temperature, pressure). The focus of this manual is to identify the various types of leak detection systems (LDSs), define a set of criteria for evaluating the performance of these systems that can be adapted to a wide range of operating pipeline systems, and provide a general evaluation of each leak detection technology to facilitate both choosing the appropriate system and evaluating the system according to BAT regulations. This manual should be regarded as a dynamic tool for BAT evaluations and should be updated periodically.

1 INTRODUCTION

1.1 OBJECTIVES

The overall purpose of this project is to identify strengths and weaknesses in industry crude oil pipeline leak detection operations and gain enough information for strategic implementation of the State of Alaska best available technology (BAT) regulations. This manual is to be used as a guidance document by the Alaska Department of Environmental Conservation (ADEC), oil industry representatives, and the public.

Project background information, regulatory framework, and research methodology are discussed in the main body of this document. Also presented are detailed discussions of the various types of leak detection systems available today. Individual evaluations for each leak detection technology are presented by vendor name under the tab "Leak Detection System Evaluations".

1.2 PROJECT BACKGROUND

In response to questions from industry and the regulatory community regarding the BAT regulations, ADEC issued a contract to identify, analyze, and report on technologies and systems that can be used to detect leaks on crude oil transmission pipelines. The technology set reviewed under this scope of work was intended to include any potential candidate technology selected by the oil industry interests in Alaska to meet the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

Due to recent changes in the regulations, BAT reviews are a required element of Oil Discharge Prevention and Contingency Plan documentation. The Plan must identify and include a written analysis of all available leak detection technologies using the applicable criteria in 18 AAC 75.445(k)(3); and include written justification that the proposed technology is the best available for the applicant's operation. The technical and performance information may be used by ADEC, industry representatives, and the public as a reference aid to determine an individual technology's suitability with respect to the general requirements of 18 AAC 75.055(a), and specific requirements of 18 AAC 75.445(k)(3). In addition, the information in this report may assist pipeline controllers in preparing the written analysis contained in BAT reviews for pipeline leak detection systems (LDSs).

1.3 REGULATORY FRAMEWORK

The U.S. Department of Transportation's Office of Pipeline Safety (DOT-OPS) regulates the transportation of hazardous liquids under the Code of Federal Regulations as legislated through the Pipeline Safety Act and its reauthorizations (49 CFR 195). These regulations were originally adapted from national standards, such as the ASME B31.4, but have evolved over time to address specific concerns of the public and Congress, typically in response to a highly visible pipeline release.

Beginning July 6, 1999, under 49 CFR Part 195, DOT-OPS will require all controllers of hazardous liquids pipelines engaged in pipeline leak detection known as computational pipeline monitoring (CPM) to use, by reference and with other information, American Petroleum Institute (API) document API 1130 *Computational Pipeline Monitoring*. Noteworthy sections of the rule include 195.2 which defines CPM; 195.3 which incorporates API 1130 into Part 195; Subpart C Design Requirements (195.134) which outlines the requirement for a CPM system; and Subpart F Operation and Maintenance (195.444) which outlines compliance with API 1130.

API 1130 defines CPM as an algorithmic, computer-based monitoring tool which allows the pipeline controller to respond to an anomaly that may indicate product release. Controllers who have no such computer-based leak-detection system are not required to install one, but those currently running such a system, or installing one in the future, must consult API 1130 in designing, evaluating, operating, maintaining, and testing their CPM systems.

BAT regulations applicable to Alaskan oil facilities and vessels became effective on April 4, 1997. All oil discharge prevention and contingency plans or plan renewals submitted to ADEC after this date must undergo a BAT review before they are approved. Elements of operations requiring the BAT review are specified in 18 AAC 75.425(e)(4). The pipeline leak detection requirement under 18 AAC 75.055(a) states that a crude oil transmission pipeline must be equipped with an LDS capable of promptly detecting a leak, including:

- If technically feasible, the continuous capability to detect a daily discharge equal to not more than one percent of daily throughput;
- Flow verification through an accounting method, at least once every 24 hours; and
- For a remote pipeline not otherwise directly accessible, weekly aerial surveillance, unless precluded by safety or weather conditions.

Under the leak detection requirement, applicants must identify all available and proven technology alternatives. Each alternative must then be evaluated in relation to the technology in place or proposed based on the criteria provided in 18 AAC 75.445(k)(3) and summarized below:

- Availability;
- Transferability;
- Effectiveness;
- Cost;
- Age and Condition;
- Compatibility;
- Feasibility; and
- Environmental Impacts.

Once this evaluation has been completed, the applicant must then provide written justification for each applicable technology determined to be the best available for the applicant's operation.

2 RESEARCH/DATA COLLECTION

The approach to researching available pipeline leak detection technologies included performing internet and literature searches for viable leak detection vendors and technologies, attending related workshops, and contacting and soliciting information from vendors and industry users. The reference materials obtained during the research phase of this project were cataloged and are available at ADEC Division of Spill Prevention and Response in Anchorage.

2.1 INTERNET SEARCH

An Internet search for leak detection vendors and oil companies using LDSs was performed. The search identified approximately 50 potential vendors and several oil companies, both domestic and foreign. Another 20 to 30 vendors were identified in the literature. Several of these vendors were immediately eliminated because they were no longer "in the business" or they dealt solely with fuel storage tank leak detection measures.

2.2 LITERATURE SEARCH

A great deal of leak detection literature was obtained from a variety of sources including API, the U.S. Environmental Protection Agency (EPA), the Oil and Gas Journal database, and Gulf Publishing. A complete set of references is available for review at ADEC. An alphabetized list of references is presented in Section 5.

2.3 WORKSHOPS AND CONFERENCES

ARCO Alaska Inc. and British Petroleum-Amoco sponsored a one-day leak detection workshop on April 6, 1999. One vendor, EFA Technologies, Inc., and industry representatives from ARCO, BP-Amoco, and Alyeska Pipeline Service Company were present. The workshop included a presentation on leak detection regulatory requirements, an overview of pipeline LDSs, and analyses of operational and proposed LDSs on Alaska crude oil transmission pipelines.

ADEC's contractor also attended the annual API Pipeline Conference in Dallas, Texas (April 20-21, 1999). A variety of leak detection information was obtained from vendors and oil industry representatives.

2.4 VENDORS

Sixty-seven leak detection vendors were contacted via email, fax, or phone and were sent a detailed questionnaire. Vendors were asked to complete the questionnaire and return it with product literature and a client reference list. Approximately 20 responses were received. Credible references identified by vendors were contacted to determine the veracity of vendor claims. A complete list of viable pipeline LDS vendors identified and evaluated is presented below.

- Acoustic Systems, Inc.
- Controlotron Corporation
- DETEX International
- EFA Technologies, inc.
- EnviroPipe Applications, Inc.
- FCI Environmental, Inc.
- LICEnergy, Inc.
- Løgstør Rør
- National Environmental Services Company (NESCO)
- PermAlert
- Physical Acoustics Corporation

- Raychem Corporation
- Siemens AG
- Simulutions Inc.
- Stoner Associates
- Tracer Research Corporation

2.5 INDUSTRY

Several companies in Alaska, the lower 48, and around the world were contacted, interviewed, and sent questionnaires to assess the effectiveness of pipeline LDSs presently being used in the field. Industry representatives were also interviewed at the annual API Pipeline Conference. A list of industry representatives that directly or indirectly participated in this project is presented below.

- Alyeska Pipeline Services Company
- Amoco Canada Petroleum Company. Ltd.
- ARCO Alaska, Inc.
- Bahrain Petroleum Company
- Boeing Petroleum Services
- British Petroleum-Amoco Alaska
- Buckeye Pipeline Company
- Cenex Pipeline
- Cook Inlet Pipeline Company
- CrossTimbers Operating Company
- Enbridge Pipeline
- Federated Pipelines Ltd.
- Marathon Oil Company
- Mid-Valley Pipeline
- Pennzoil Company
- Phillips Petroleum Company
- Shell Oil Products
- Sun Pipeline Company
- Texaco Company
- TransAlpine Company
- Trans Mountain Pipeline Company
- Unocal Corporation
- U.S. Defense Fuel Supply Command

3 PIPELINE LEAK DETECTION SYSTEMS

Methods used to detect product leaks along a pipeline can be divided into two categories, externally based (direct) or internally based (inferential). Externally based methods detect leaking product outside the pipeline and include traditional procedures such as right-of-way inspection by line patrols, as well as technologies like hydrocarbon sensing via fiber optic or dielectric cables. Internally based methods, also known as computational pipeline monitoring (CPM), use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation (API, 1995a).

The method of leak detection selected for a pipeline is dependent on a variety of factors including pipeline characteristics, product characteristics, instrumentation and communications capabilities, and economics (Muhlbauer, 1996). Pipeline systems vary widely in their physical characteristics and operational functions, and no one external or internal method is universally applicable or possesses all the features and functionality required for perfect leak detection performance. However, the chosen system should include as many of the following desirable leak detection utilities as possible (API, 1995a):

- Possesses accurate product release alarming;
- Possesses high sensitivity to product release;
- Allows for timely detection of product release;
- Offers efficient field and control center support;
- Requires minimum software configuration and tuning;
- Requires minimum impact from communication outages;
- Accommodates complex operating conditions;
- Is available during transients;
- Is configurable to a complex pipeline network;
- Performs accurate imbalance calculations on flow meters;
- Is redundant;
- Possesses dynamic alarm thresholds;
- Possesses dynamic line pack constant;
- Accommodates product blending;
- Accounts for heat transfer;
- Provides the pipeline system's real time pressure profile;
- Accommodates slack-line and multiphase flow conditions;
- Accommodates all types of liquids;
- Identifies leak location;
- Identifies leak rate;
- Accommodates product measurement and inventory compensation for various corrections (i.e., temperature, pressure, and density); and

- Accounts for effects of drag reducing agent.

The following sections present a detailed discussion of the major components of a typical computer-based pipeline LDS, as well as descriptions of several externally and internally based leak detection technologies. For each technology, a list of evaluated vendor-specific systems is presented.

3.1 MAJOR COMPONENTS OF A COMPUTER-BASED LDS

The utilization of computer systems in pipeline monitoring allows the greatest amount of data to be collected, analyzed, and acted upon in the shortest amount of time. For these reasons, most pipeline systems today employ some form of computer-based monitoring using commercially available or custom-designed software packages to run the system (Furness and van Reet, 1998). Leak detection is just one of many functions that can be performed with computer-based systems, which generally consist of two major elements: instrumentation and a supervisory computer with associated software and communications links.

3.1.1 Instrumentation

Instrumentation includes the flow meters, pressure transducers, sensors, and cables situated along the pipeline (externally or internally) which measure parameters such as line pressure, temperature, flow, product characteristics, and the presence of hydrocarbons. Because the effectiveness of any pipeline LDS is limited primarily by the sensitivity and accuracy of the installed instrumentation, it is critical to select the best performing setup for a given operating scenario. Instrument specifications should be prudently compared to a pipeline's operating design to make the best use of the manufacturer's declared accuracy and linearity (API, 1995a). Additionally, all practical means should be taken to reduce sources of instrument noise[1], which can inhibit the performance of an LDS. Mechanical resonance and electrical interference are primary sources of instrument noise. Mechanical resonance must be considered during the design of process piping and placement of the instrument package. Proper instrument grounding and the use of shielded signal cables will serve to reduce electrical noise. If these measures of noise reduction are not successful, signal conditioning (bandwidth adjustment, digital filters, or data smoothing programs) may be required.

Another means of reducing the impact of mechanical noise on pipeline systems is the use of inline surge or divert tanks. Popular in the lower 48 states and used on at least one North Slope line, surge tanks lessen the impact of pressure wings and system noise on meters that could potentially result in measurement errors, damage, or undue wear. Surge tanks may result in an increase in leak detection sensitivity by allowing the operator to lower alarm thresholds.

McAllister (1998) provides some general guidelines to follow when selecting field instrumentation:

- Choose instrumentation based on performance and not economic grounds. It is better to install fewer high quality pieces of equipment than numerous poor ones.
- Equipment compatibility is important. Use transducers, interface modules, and other hardware that use standard communications protocol.

[1] Noise is that part of a signal that does not represent the quantity being measured (API, 1995a). Fluctuations around a fixed or moving mean are considered noise.

- Where possible, install instruments that are self-checking or self-diagnosing, or install dual systems.
- Seek independent references, user experience, or validation of the instruments chosen. Most equipment performs differently in real applications than under the published ideal conditions.

Pipeline flow meters and pressure transducers are described below. Other sensors, cables, and instruments specific to LDSs are described in Sections 3.2 or 3.3, as appropriate. To supplement this discussion, API Publication 1149, *Pipeline Variable Uncertainties and Their Effects on Leak Detectability*, also documents the importance of field instrumentation to leak detection performance.

3.1.1.1 Flow Meters

Flow measurement is the most important process variable in the operation and control of pipelines; therefore, flow meters are one of the most important instruments installed on a system (McAllister, 1998). Several different types of flow meters are used on pipelines including orifice plates (differential pressure), turbine, positive displacement, mass flow (Coriolis type), and ultrasonic time-of-flight (clamp-on)[2]. This section describes the various types of flow meters, their accuracies, advantages, and disadvantages.

The flow meters most often installed on pipelines are sharp-edged orifice plates, a differential pressure type of meter. Although the use of these types of meters is very common in processes such as the metering of natural gas, their use as accurate instrumentation for pipeline leak detection is questionable. The biggest problem is the measurement uncertainty associated with these instruments. Vendors claim orifice plates are accurate to within 0.5% of flow; however, when all the other variables that can affect uncertainty measurement are considered—fluid composition changes, temperature and pressure variations, conversion and computational errors, etc.—it is unreasonable to assume that accuracies better than 3 to 5% can be achieved (McAllister, 1998).

Turbine meters are flow-measuring devices with rotors that sense the velocity of flowing liquid in a closed conduit. The flowing liquid forces the rotor to move with a tangential velocity proportional to the volumetric flow rate (API, 1995c). Turbine meters are used extensively on pipelines, especially those carrying petroleum hydrocarbons (McAllister, 1998). Among the instruments in this family of flow meters are the custody transfer meters used to bring oil to market. Turbine flow meters tend to be more accurate than other types (i.e., custody transfer meters are reportedly accurate to within 0.05% of throughput), but still suffer from limitations such as calibration shift. Their volumetric accuracy depends on the measured dimensions of the pipeline section, the amount of drag in the turbine's rotor, and the degree of system proving. Fortunately, recent developments have resulted in self-diagnosing twin rotor meter designs, which can detect shifts in calibration caused by bearing wear and blade damage (McAllister, 1998). The microprocessors in these twin rotor meters can also check the integrity of the data generated by the meters and provide alarm output for verified problems. Other variables that may affect turbine meter performance are variations in flow rate, viscosity, temperature, density, and pressure (API, 1995c).

[2] Regardless of how volumetric flow is measured or computed, API standards require that all meters be "proven" or regularly calibrated against a known and accepted standard.

Positive displacement meters measure flow by moving the liquid through a pipe section of known volume. The claimed accuracy of these meters is 0.1 to 0.2% of flow. The accuracy of these meters depends on the accuracy to which the dimensions of the pipe section are known, the extent to which it effectively contains the product, and the temperature and pressure conditions under which the measurements are made (Diane Hovey, EFA Technologies, written commun., 1999).

Another flow meter that is slowly gaining acceptance and being incorporated into the pipeline industry is the Coriolis direct mass meter (McAllister, 1998). The accuracy of these instruments is approximately +/-0.5% of reading or better. The advantage of direct mass measurement over the more common volumetric assessment is that the integration of the instrument signal provides the pipeline fluid inventory directly. Additional measurements of temperature, pressure, and equation of state to determine fluid density are not necessary. The principal disadvantage is the current size range of the meters. Most major pipelines are in the 500 to 2,000 millimeter (mm) bore range, but the largest available direct mass meter is only 150 mm bore. This means that several Coriolis meters would have to be installed in parallel to be effective. Additionally, API does not envision that these meters will be used for custody transfer measurements in the near future.

The ultrasonic transit-time flow meters are installed on the outside of the pipeline. These clamp-on flow meters are reportedly accurate to within 0.001 ft/sec at any flow rate, including zero. However, measurement engineers hold the installed accuracy of these meters to be no better than 2% of flow (McAllister, 1998). Ultrasonic meters have the advantages of negligible headloss and the ability to install additional instrumentation without line shutdown.

3.1.1.2 Pressure Transducers

Pressure-measuring devices may be divided into three groups: those based on measurement of the height of a liquid column; those based on measurement of the distortion of an elastic pressure chamber; and electronic sensing devices. Conventional pressure transducers found on pipelines generally are of the electronic sensing type with various means of discerning pressure (piston, diaphragm, strain gauge, piezoelectric sensors, variable capacitance, and variable element). Pipeline pressure is measured by the displacement of these devices in response to fluid pressure and is converted electronically to an appropriate current, voltage, or digital output signal. The sensors typically are ceramic, silicon, or stainless steel. Ceramic is corrosion and abrasion resistant, has superb electrical isolation, and a high natural frequency. Silicon, an elastic drift-free material, offers low cost and is the most common material used. The accuracy of these transducers is typically +/-0.1% of span.

Recent developments in microprocessing have resulted in the creation of a new generation of “smart” pressure transducers. These intelligent sensors rely on the properties of silicon and microelectronics for optimum performance (McAllister, 1989). The advantages of these transducers are listed below.

- Signal processing is digital and algorithms can be written to cope with any signal/pressure curve, provided it is repeatable;
- Advanced communications capabilities, including remote access and online instrument rearranging;
- On-line temperature compensation;

- Built in diagnostics; and
- Claimed accuracies of better than +/-0.1% of span.

Another type of pressure transducer that has potential pipeline applications is the vibrating wire sensor. This transducer operates on the premise that as pressure changes, the tension on a tungsten wire enclosed in a silicon diaphragm is altered, and the result is a measurable change in the resonating frequency of the wire (McAllister, 1998). The change in frequency is sensed and amplified, and data are provided to the pipeline controller. Pressure and temperature compensation is accomplished within the instrument. While it has shown considerable reduction in size and manufacturing costs from other sensors, this technology is still in the experimental stage and has not been extensively applied in the field.

3.1.2 SCADA/Communications

The Supervisory Control and Data Acquisition (SCADA) system is a computer-based communications system that monitors, processes, transmits, and displays pipeline data for the controller (API, 1995a; Borener and Patterson, 1995). SCADA systems may be used directly for leak detection, they may provide support for an LDS, or an LDS may operate independently of SCADA. Generally, a pipeline LDS will use the data generated by a SCADA system to aid in assessing the potential for a product release.

SCADA systems collect real-time data from field instruments using Remote Terminal Units (RTUs), Programmable Logic Controllers (PLCs), and other electronic measurement devices, which are placed at intervals along the pipeline. Communication with these devices can occur in many ways, including microwave, cellular, satellite, leased line, etc., but the most common media are dedicated phone circuits and terrestrial- and satellite-based radio systems (API, 1995a). An emerging trend is to use multiple methods of communicating based on the concept that each method will have a cost or performance advantage for a given installation (Whaley and Wheeler, 1997).

Data from RTUs or PLCs are gathered into a Master Terminal Unit (MTU) which consists of one or more central computers built around a real-time, memory-resident database. The MTU displays the current operating conditions for the controller, who, in turn, can act on these data if necessary. Messaging between the field devices and the MTU is known as the communications protocol (API, 1995a). The protocol is considered “polled” when the MTU requests data from each device consecutively. When the last device is scanned, the MTU will automatically request information from the first one, creating a ceaseless polling cycle. The SCADA system polling rate, the time between successive communications between the RTU and MTU, has steadily improved over the years and has been reduced to less than 0.25 seconds in high priority areas on some pipelines (Ed Farmer, presentation, April 1999). SCADA communications may also be non-polled. For example, RTUs may report without being polled on a time-scheduled basis or when field conditions change. LDSs that rely on the SCADA system to receive operating data are directly affected by the polling rate. Longer polling cycles typically translate to degraded leak detection sensitivity.

Most modern SCADA systems include quality checking software to assess the validity of the data before any calculations are computed and displayed (McAllister, 1998). Research suggests that this type of continuous quality control greatly improves the sensitivity of the system. In addition, advanced SCADA systems can include predictive modeling to assess “what if” operating scenarios, handle automatic startup and shutdown routines, and evaluate operating strategies for cost-benefit optimization (McAllister, 1998).

For additional discussion of SCADA system design factors and their effects on the quality and timeliness of the data required by an LDS, see API Document 1130, *Computation Pipeline Monitoring* (1995a).

3.2 INTERNAL LEAK DETECTION SYTEMS

Results of the literature search have shown that the main category of inferential leak detection in pipelines is known as computational pipeline monitoring (CPM). CPM refers to algorithmic monitoring tools that are used to enhance the abilities of a pipeline controller to recognize anomalies which may be indicative of a product release (API, 1995a). CPM operates by providing an alarm and displaying other related data to the controller who, in turn, would investigate the reason for the alarm and initiate a response if the anomaly represents a product release. CPM does not include externally based LDSs which operate on the non-algorithmic principle of physical detection of a product leak (API, 1995a). Externally based leak detection methods are presented in Section 3.3.

CPM mainly relies on the data collected from the field instruments, which are continuously input into a computer program that mathematically or statistically analyzes the information. Analysis results are produced in the form of parameter estimates, which in turn are subjected to some probability law or decision criteria to determine if a leak is present (API, 1995b). The degree of complexity in analyzing field data ranges from the comparison of a single element (i.e., pressure) relative to a threshold limit to extensive analyses of multiple elements with dynamic thresholds. Without the computer program and associated algorithms, the data would be difficult if not impossible to interpret in a timely manner. Consequently, the heart of any CPM system is the computer program. The classes of CPM are differentiated by the types of instruments and programs (or algorithms) used. There are three basic types of CPM: volume (or mass) balance, pressure analysis (rarefaction wave monitoring), and real time transient modeling (RTTM). Note that some of the leak detection systems offered by vendors include more than one type of leak detection method (i.e., both volume balance and pressure analysis). Additionally, most of the volume balance and RTTM leak detection systems use some sort of pressure analysis to locate leaks.

3.2.1 Volume Balance

The volume balance method of leak detection, also known as line balance, compensated volume balance, or mass balance, is based on measuring the discrepancy between the incoming (receipt) and outgoing (delivery) product volumes of a particular pipeline segment (API, 1995a). During a unit time interval, the volume of product that enters a pipe may not be equal to the measured volume exiting the pipe. The difference is accounted for by uncertainties in line pack and flow measurement. This relationship is stated below:

$$\left|Q_{in} - Q_{out}\right| \leq dQ_m + \frac{dV_s}{\Delta t}$$

Where,
Q_{in} = Measured Inflow
Q_{out} = Measured Outflow

dQ_m = Bound of uncertainty in flow measurement
dV_s = Bound of uncertainty in line pack change over a time interval Δt

If a leak exists it can only be detected if the following relationship is fulfilled:

$$Q_l = Q_{in} - Q_{out} > dQ_m + \frac{dV_s}{\Delta t}$$

Where,
Q_l = Flow rate of the leak

The principal differences among the various volume balance methods are outlined below.

- Basic line balance does not compensate for changes in line pack due to pressure, temperature, or product composition.
- Volume balance is an enhanced, automated technique, which does account for line pack correction by assessing changes in volume due to temperature and/or pressure variations. A representative bulk modulus is used for line pack calculations.
- Compensated volume balance is an enhanced volume balance technique which accounts for volume change using a dynamic bulk modulus to assess line pack correction.
- Mass balance accounts directly for product density (i.e., with online densitometers).

Ultrasonic systems detect leaks via transient-compensated volume or mass balance; therefore, they are included under this heading. These systems typically operate through accurate tracking of flow rate, computation of pressure, temperature, and product characteristics, and determination of sonic profiles using external clamp-on instruments configured with data processing equipment.

Compared to other leak detection methods, volume balance is particularly useful in identifying small leaks. However, leaks are generally detected more slowly and flow metering at each end of the line or pipeline segment will not identify the location of the leak. Most of the software-based volume-balance systems incorporate additional algorithms for leak location based on pressure analysis.

Volume balance LDSs that were evaluated for this project include EFA Technologies, Inc.'s MassPack™ (part of their LEAKNET™ system) and EnviroPipe Applications, Inc.'s LEAKTRACK 2000. Ultrasonic systems include Controlotron Corporation's System 990LD™ and DETEX International's Series 2000. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.2.2 Pressure Analysis (Rarefaction Wave Monitoring)

The rarefaction wave (also called an acoustic, negative pressure, or expansion wave) method of leak detection is based on the analysis of pipeline pressure variations. When product breaches the pipeline wall there is a sudden drop in pressure at the location of the leak followed by rapid line repressurization a few milliseconds later. The resulting low-pressure expansion wave travels at the speed of sound through the liquid away from the leak in both directions. Instruments placed at intervals along the pipeline respond as the wave passes. If a leak occurs in the middle of a line segment with uniform construction, the rarefaction wave should be seen at opposite ends of the line simultaneously. If the leak is closer to one end, it should be seen first at the close end and later at the far end. The time evidence recorded at each end of the monitored line or segment is used to calculate the location of the leak. Most volume balance and RTTM leak detection systems use pressure analysis to locate leaks. Models also use pressure measurements as boundary conditions.

Since the rarefaction wave travels at significant speeds, on the order of one mile per second, this method of leak detection is particularly useful in identifying large leaks rapidly. Smaller leaks typically take longer to detect and very small, pinhole leaks may go undetected. The success of a rarefaction wave LDS largely depends on the frequency and sensitivity of instrument measurements. Because of the sensitivity of this type of technology to operational changes that result in large transient pressure waves, leak detection performance generally falls off under highly transient, slack-line, and multi-phase flow conditions.

The principal difference among the various rarefaction wave technologies is how the wave is identified and monitored. Some sensors or transducers monitor for the leading edge of the wave while others evaluate the shape of the wave.

Pressure analysis (rarefaction wave monitoring) LDSs that were evaluated for this project include EFA Technologies Inc.'s Pressure Point Analysis (PPA)™ (part of the LEAKNET™ system), Acoustic Systems Inc.'s WaveAlert®, and Tracer Research Corporation's LeakLoc®. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.2.3 Real Time Transient Modeling

The most sensitive, but also the most complex and costly leak detection method in use is real time transient modeling (RTTM). RTTM involves the computer simulation of pipeline conditions using advanced fluid mechanics and hydraulic modeling (Borener and Patterson, 1995). Conservation of momentum calculations, conservation of energy calculations, and numerous flow equations are typically used by the RTTM system. RTTM software can predict the size and location of leaks by comparing the measured data for a segment of pipeline with the predicted modeled conditions. This analysis is done in a three-step process. First, the pressure-flow profile of the pipeline is calculated based on measurements at the pipeline or segment inlet. Next, the pressure-flow profile is calculated based on measurements at the outlet. Third, the two profiles are overlapped and the location of the leak is identified as the point where these two profiles intersect. If the measured characteristics deviate from the computer prediction, the RTTM system sends an alarm to the pipeline controller. The more instruments that are accurately transmitting data into the model, the higher the accuracy of and confidence in the model. Note that models rely on properly operating and calibrated instruments for optimum performance. Calibration errors can result in false alarms or missed leaks, and the loss of a critical instrument could require system shutdown.

The advantage RTTM provides over other methods is its ability to model all of the dynamic fluid characteristics (flow, pressure, temperature) and take into account the extensive configuration of physical pipeline characteristics (length, diameter, thickness, etc.), as well as product characteristics (density, viscosity, etc.) (API, 1995a). Additionally, the model can be tuned to distinguish between instrument errors, normal transients, and leaks. The distinct disadvantages of this LDS are the costs associated with implementing RTTM and the complexity of the system, which requires numerous instruments and extensive controller training and system maintenance.

RTTM LDSs that were evaluated for this project include LICEnergy Inc.'s Pipeline Leak Detection System (PLDS), Simulutions Inc.'s LEAKWARN, and Stoner Associate's SPS/Leakfinder. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.3 EXTERNAL LEAK DETECTION SYSTEMS

3.3.1 Acoustic Emissions

Leak detection in pipelines using acoustic emissions technology is based on the principle that escaping liquid creates an acoustic signal as it passes through a perforation in the pipe. Acoustic sensors affixed to the outside of the pipe monitor internal pipeline noise levels and locations. These data are used to create a baseline "acoustic map" of the line. When a leak occurs, the resulting low frequency acoustic signal is detected and analyzed by system processors. Deviations from the baseline acoustic profile would signal an alarm. The received signal is stronger near the leak site thus enabling leak location.

Acoustic sensing can be applied externally to buried pipelines by using steel rods driven into the ground to conduct the sound to a sensor mounted on the rod. The rods are inserted at intervals along the pipeline.

Physical Acoustic Corporation's Acoustic Emissions LDS was evaluated for this project. The BAT evaluation for this technology is presented under the tab "Leak Detection System Evaluations".

3.3.2 Fiber Optic Sensing

With this technology, fiber optic sensing probes are driven into the soil beneath or adjacent to the pipeline. In the presence of hydrocarbons, the patented covering of the sensor changes its refractive index. This change is registered optically by the sensor and converted to a parts-per-million reading of hydrocarbons.

FCI Environmental, Inc.'s PetroSense® was the only LDS based on fiber optics evaluated for this project. The BAT evaluation for this technology presented under the tab "Leak Detection System Evaluations".

3.3.3 Liquid Sensing

Liquid sensing cables are buried beneath or adjacent to a pipeline and are specifically designed to reflect changes in transmitted energy pulses as a result of impedance differentials induced by contact with hydrocarbon liquids. Safe energy pulses are continuously sent by a microprocessor through the cable. The pulses are reflected and returned to the microprocessor. Based on the specific installation of the cable, a baseline reflection map is stored in the memory of the microprocessor. When a leak occurs, the cable is saturated with fluid. The fluid alters the impedance of the sensing cable, which in turn alters the reflection pattern returning to the microprocessor. The change in signal pattern causes the microprocessor to register a leak alarm at the location of the altered impedance. Controller interface software is available to provide real-time information on leak detection and record keeping. Specific cable types are chosen for each application based on the specific fluid being monitored.

Liquid sensing leak detection is typically marketed as a self-contained leak detection and location system, including all hardware and software. Advantages include relatively high accuracy in determining leak location, no modifications to existing pipeline, and easy software configuration and maintenance. Disadvantages include very high installation costs and extensive power and signal wiring requirements.

Liquid-sensing cable LDSs that were evaluated for this project include PermAlert's PAL-AT®, Raychem Corporation's TraceTek, and Løgstør Rør's LR-Detector. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.3.4 Vapor Sensing

Hydrocarbon gas sensing systems are more frequently used in storage tank systems but can also be applicable to pipelines. Leak detection using vapor-monitoring techniques is a fairly straightforward concept. When a liquid seeps into the soil, vapors migrate from into the surrounding soil pore spaces. Probes are arranged in the soil so that a vacuum may be applied to them. The soil vapors are collected for laboratory or field analysis. Tracers or chemical markers may be added to the product being monitored so that it may be identified from naturally occurring background vapors. When the tracers or markers are encountered during analysis of the vapors, it can be surmised that a leak has occurred.

The vapor sensing tube leak detection method involves the installation of a secondary conduit along the entire length of the pipeline. The conduit may be a small-diameter perforated tube attached to the pipeline or it may completely encompass the pipeline, allowing the annular headspace to be tested. Air gas samples are drawn into the tube and analyzed by hydrocarbon vapor sensors to determine the presence of a leak. Because of the logistical problems associated with any system installed along the entire length of a pipeline, vapor-sensing tubes are usually only employed on short lines.

Vapor-sensing LDSs that were evaluated for this project include National Environmental Services Company's Soil Sentry 12XP, Tracer Research Corporation's Tracer Tight®, and Siemens AG LEOS® system. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.4 PERFORMANCE ISSUES

The LDSs discussed in this report are affected by operational factors that may contribute to a deterioration of performance. This section discusses these factors as performance issues limiting the quality of data acquired by the LDS. A more detailed discussion of the limitations of CPM systems may be found in API Publication 1130, *Computational Pipeline Monitoring*.

3.4.1 Multiphase and Slack-Line Effects

Multiphase flow, the simultaneous flow of oil and gas or of oil, gas, and water through one pipe, can occur as a number of different flow patterns (McAllister, 1998):

1. Bubble flow — bubbles of gas flow along the upper part of the pipe at about the same velocity as the product;
2. Plug Flow — the bubbles of gas coalesce into large bubbles which occupy the large part of the cross-sectional area of the pipe;

3. Laminar Flow — the gas-liquid interface is relatively smooth with gas flowing in the upper portion of the pipe;
4. Slug Flow — the tops of some waves on the surface of the liquid reaches the top of the pipe. These slugs move with high velocity;
5. Annular Flow — the liquid flows along the walls of the pipe and the gas moves through the center with high velocity; and
6. Spray Flow — the liquid is dispersed within the gas.

Multiphase flow can occur in a petroleum pipeline for a number of reasons. In the case of crude oil gathering lines, water and gas can be produced with the oil in production wells of mature fields where water flood enhanced oil recovery is used to maintain field pressures, and/or the gas/oil ratio has become elevated following the removal of oil from the reservoir. Multiphase flow may be communicated to a delivery line fed by a production facility in the event its water or gas removal system malfunctions, or cannot keep up with surges of gas and water from gathering lines.

Because water, oil, and natural gas have significantly different physical characteristics, multiphase flow can cause line pressures to change as they pass a point in the line; thus, confounding attempts to gauge internal line pressures on a real-time basis. The erratic pressure swings caused by multiphase flow adversely affect the signal from pressure transducers and may lead to poor-quality input data and/or multiple false alarms.

Slack-line conditions occur where flow is not sufficient to keep the entire volume of the pipe filled with liquid. Under this condition, the pipeline will have "pockets" of volume not occupied by flowing liquid. These regions will be related to line topography and flow rates and, in effect, represent a transient storage term in modeling pipeline flow characteristics. Real time transient modeling is capable of dealing with this transient storage effect, albeit at degraded sensitivities, whereas volume balance methods may misinterpret loss to and gain from the slackline as a leak from or false input to the pipeline. Pressure analysis may also provide erratic results based on slackline volume changes and associated changes in the pressure-volume relationship within the slack-line areas.

3.4.2 Pre-Existing Leaks

Leaks existing during startup of a pressure analysis system will not be detected, rather, the pressure data used to calibrate and run the system will include the perturbation from the leak as the normal baseline condition. Similarly, small leaks that become larger may not be detected until their effect exceeds the rate-of-change boundary condition criteria set for the instruments. However, these situations are rare. Line and volume balance methods will detect such conditions provided the leak rate is greater than the precision limits of the metering devices used.

3.4.3 Variations in Temperature, Pressure, & Flow Conditions

Most RTTM, compensated volume balance, and pressure analysis systems are capable of correcting for pressure/temperature/volume (i.e., line pack) relationships within the pipeline. Line balance or other systems that do not account for these relationships may send false alarm signals because of apparent pressure or volume losses related to temperature changes.

3.4.4 Connected Production Areas

LDSs placed in a pipeline between two or more production areas may respond to flow rate and pressure fluctuations coming from upstream or downstream directions. Thus, operational transients in one production area or pipeline segment may be sensed as a leak by an LDS component assigned to another. Pressure analysis leak detection with leak location software should be capable of isolating the source area of suspect pressure anomalies within a section of pipeline. Sources of pressure change coming from outside the pipe segment being monitored by a given system will be flagged as foreign by the leak detection software. One way to minimize the effects of pressure anomalies on leak detection is to install in-line surge tanks, which reduce pipeline noise and enhance leak detection sensitivity (see Section 3.1.1).

3.4.5 False Alarms

As discussed, many factors contribute to an elevated signal-to-noise ratio with an internal LDS. Some factors are known (i.e., engineered production rate changes, well shut-ins, and diversion to and from tank storage), others are less predictable (slugging, effects from pipeline feed changes in connected production areas). Over time, repetitious false alarms may degrade the quality of response to future alarms irrespective of their cause. If possible, a threshold level of alarms per week or month may be prescribed based on systematic causes. This fine tuning may be achieved through the adjustment of SCADA analog deadband threshold settings or through the use of data filtering programs that eliminate, or at least flag, line perturbations caused by normal system fluctuations. Dangers exist in relying solely on changed settings to reduce the frequency of leak detection alarms. First, the precision required to detect a leak of a desired size may be lost if thresholds or filters attenuate or block the signal significantly. Second, the quality of the response to future alarms may become degraded if controllers become accustomed to long periods of time without reacting to them.

Use of rules-based logic or expert systems within an LDS will be a major enhancement in terms of reducing or eliminating the number of false alarms in the near future (Whaley and Wheeler, 1997). Most LDSs currently include simple rules for alarming when high or low limits are exceeded or when measured values change too rapidly. The problem with these simple limits is that they lead to a proliferation of frequently meaningless alarms and are unable to evaluate situations involving multiple points or sites. Rules-based logic has the potential of reducing the amount of data controllers must review while increasing the amount of meaningful information. Rules do this by automating the analysis performed by a controller to check out the meaning of limit alarms and by allowing more complex checks of multiple sites or values. Drawbacks to the use of these systems include the high cost of purchasing a third-party artificial intelligence package and the high degree of technical expertise required to set up and maintain it.

The number of false leak alarms appropriate for a given system is site and application specific. The frequency of false alarms and the appropriate response to them should be part of the operational program in a facility using any leak detection technology.

3.4.6 Instrumentation

Instrumentation used to detect changes in pressure, temperature, and flow, must be calibrated and checked routinely. API recommends that each pipeline company implement a test and calibration plan as part of a CPM operating and maintenance procedure. The calibration and testing of instrumentation in the LDS should be based on manufacturer recommendations and on historical LDS performance.

Additionally, the devices selected for incorporation into an LDS must afford sensitivity necessary to attain leak detection goals. For example, turbine meters may be selected over orifice meters for greater than one percent accuracy in flow modeling.

The sensitivity of a volume balance LDS is ultimately determined by the combined or aggregate accuracy of the flow meters themselves. Aggregate accuracy typically is evaluated in terms of the standard deviations of the individual meters involved in closing the mass balance, or the "root-sum-squared" method (D. Hovey, written commun., 1999). The basic formula is presented below.

Aggregate Meter Accuracy = Square Root ($a_1^2 + a_2^2 + a_3^2 + ...+ a_n^2$)

Where a_n is the accuracy of the nth meter.

For example, a system with two meters, each 2 percent accurate, would have an aggregate accuracy of 2.8 percent. If one of these meters is replaced by a meter that is 0.1 percent accurate, the aggregate accuracy would become 2.0 percent. Note that the accuracy of the least accurate meter controls this equation. Ideally, a system should be designed with the fewest number of high-quality sensing devices as practical.

3.4.7 Controller Training

Because of the complexity of LDS technology, the pipeline controller should be trained to recognize the significance of alarms and their potential causes. The significance of the measurement data and credibility of alarms generated by any LDS may be lost if the ability to perform this type of analysis is compromised. API divides alarms into three categories: data failure, transient pipeline operating condition, and possible product release. The pipeline controller must have adequate training to discriminate between the various causes of alarms and respond appropriately. Controller training should include response to a minimum number of false alarms and the use of tests simulating releases.

3.4.8 Redundant Systems

It should be emphasized that in some situations more than one LDS might be appropriate for attaining BAT. Redundant systems may offer faster detection speeds and lower leak volume thresholds than a single system. For example, a combination of mass balance (which can detect small volume leaks) and rarefaction wave analysis (which can detect large leaks very rapidly) would offer a combination of sensitivity, speed, and a leak location ability that might be considered BAT for a particular application.

4 LEAK DETECTION TECHNOLOGY EVALUATION

As noted in Section 1.3, the ADEC BAT evaluation is focused on the performance and suitability criteria listed in 18 AAC 75.445(k)(3). These criteria were combined with related performance and limitation considerations to construct a leak detection technology evaluation strategy. Note that ADEC's Age and Condition[3] criterion will not be used in the evaluation because it is a pipeline-specific parameter. Additionally, due to the variability in pipeline sizes and operating conditions, the leak detection Cost criterion is evaluated only qualitatively for each technology.

The evaluation criteria used in this assessment constitute just one set of general information that a pipeline company can use to determine the best available leak detection technology for their particular pipeline. They must also, on a pipeline-specific basis, be capable of performing the following functions:

- Identify any additional contractual or legal requirements relating to leak detection
- Characterize the pipeline in terms of its possible leak mechanisms and the likelihood that one of them will result in a leak. Factors include, but are not limited to, length and volume of the pipeline; pressure, temperature, and flow rate envelope; terrain; product characteristics; and pipeline operating and maintenance procedures;
- Determine the leak detection potential of the pipeline. A generic spreadsheet prepared by Enbridge Pipelines Inc. and based on principles outlined in API Publication 1149 (*Pipeline Variable Uncertainties and Their Effects on Leak Detectability*) is available on the floppy disc accompanying this manual or at ADEC; and
- Perform an assessment of definite and potential costs associated with incorrectly declaring leak alarms, missed alarms, late alarms, and any other deviation from ideal leak detection system performance (API, 1995b).

4.1.1 Applicability/Availability

The applicability criterion simply serves to ensure that any technology selected for use on a crude oil pipeline system was designed for that intended use. Availability refers to the commercial availability of an LDS and its components.

4.1.2 Effectiveness

Effectiveness deals primarily with the performance related aspects of an LDS and is evaluated in terms of sensitivity, accuracy, reliability, and robustness. Unfortunately, focus on attaining ideal performance in one area, say sensitivity, usually results in some degradation of the other criteria. To exemplify this, consider the following hypothetical leak detection systems (API, 1995b):

System I: This system employs a sensitive leak detection algorithm. The system is normally very reliable, but will frequently generate alarms during normal pipeline operations.

[3] This criterion refers to the age and condition of the leak detection technology in use by the applicant. If the existing leak detection system is being maintained in reliable operating condition, and is shown to have the capability to achieve the same expected results as a new technology, then ADEC may determine that there is no benefit in replacing the existing technology.

System II: This system employs an alternative algorithm which is somewhat less sensitive than that of System I, but generates only a fraction of the alarms.

System III: This system employs the same sensitive leak detection algorithm as System I, but inhibits leak detection during pipeline operations that can cause it to generate alarms.

System IV: This system normally employs the same sensitive leak detection algorithm as System I, but switches to the less sensitive algorithm of System II when it senses conditions that generate alarms.

In order to maintain a high level of sensitivity, the designers of System I have sacrificed a degree of reliability, whereas the designers of System II have decided to sacrifice some degree of sensitivity in order to achieve a high level of reliability. By disabling the leak detection capability under certain conditions, the designers of System III have sacrificed a degree of robustness in order to achieve higher levels of sensitivity and reliability. System IV represents and attempts to achieve a more robust system at the expense of sensitivity and reliability.

Most leak detection technologies attempt to attain a satisfactory tradeoff between sensitivity, accuracy, reliability, and robustness by understanding the specific operating conditions of a pipeline and the controller's expectations. The LDS ultimately selected by a pipeline company will depend upon the performance requirements specific to that company. No one LDS technology is suitable for all pipeline applications.

4.1.2.1 Sensitivity

Sensitivity is defined as the composite measure of the size of leak that a system is capable of detecting, and the time required for the system to issue an alarm in the event that a leak of that size should occur (API, 1995b). The relationship between leak size and the response time is dependent upon the nature of the LDS. Some systems manifest a strong correlation between leak size and response time, while with others, response time is largely independent of leak size. Note that there are no known systems that tend to detect small leaks more quickly than large leaks.

Sensitivity is evaluated according to ADEC regulations specifying that a technology have the continuous capability to detect a leak equal to not more than one percent of daily throughput. In terms of response time, the regulations specify only that a system be capable of detecting leaks "promptly." Response times from field performance data are presented in the evaluation, but it is the pipeline controller's responsibility to establish an appropriate response time for his/her pipeline.

4.1.2.2 Accuracy

Accuracy is a measure of LDS performance related to estimation parameters such as leak flow rate, total volume lost, and leak location (API, 1995b). A system that estimates these parameters within an acceptable degree of tolerance, as defined by the pipeline controller/company, is considered to be accurate. Often times an LDS will use existing pipeline instrumentation such as flow meters and pressure transducers in their processes. The accuracy of these systems is evaluated in terms of the accuracy, repeatability, and precision of the recommended or provided pipeline instruments themselves. Instrument accuracy represents the measurement performance of the instrument relative to that of an ideal device. Repeatability is a measure of the instrument's ability to consistently return the same reading for a given set of conditions.

Precision is a measure of the smallest change that can be seen in the output of the instrument.

For this project, leak location accuracy is discussed in terms of the capability of a technology to locate the leak within a certain percentage of a given pipe segment or within so many feet of an indicating sensor.

4.1.2.3 Reliability

Reliability is a measure of the ability of an LDS to render accurate decisions about the possible existence of a leak on a pipeline (API, 1995b). It is directly related to the probability of detecting a leak, given that a leak does in fact exist, and the probability of incorrectly declaring a leak, given that no leak has occurred. A system which incorrectly declares leaks is considered to be less reliable; however, if the system has the capability to use additional information to disqualify, limit, or inhibit an alarm, a high rate of leak declarations may be considered less significant.

Reliability pertains only to the leak detection hardware and software, not the SCADA system, pipeline instrumentation, communication equipment, or any other factor beyond the control of the vendor. Reliability can be managed through controller response and established procedures; however, unless the LDS automatically adjusts to decision thresholds, these procedures cannot be used to discriminate between systems. For this project, the reliability of a leak detection technology is evaluated in terms of the frequency and cause of reported false alarms on operating pipeline systems, and the ability of the LDS to automatically evaluate line conditions and adjust alarms thresholds.

4.1.2.4 Robustness

Robustness is a measure of an LDS's ability to continue to function and provide useful information, even under changing conditions of pipeline operation (API, 1995b). A system is considered robust if it continues to perform its principle functions under less than ideal conditions. For this project, robustness is evaluated in terms of the capability of the LDS to distinguish between normal transient operating conditions and real leak events, and the ability to automatically make temporary system adjustments or disable certain leak detection functions as needed. Robustness is also evaluated in terms of the ability of an LDS to continue to perform in the event that an instrument is lost or goes off line.

4.1.3 Transferability/Feasibility

This criterion requires a close examination of expected pipeline operating conditions. The performance issues presented in Section 3.4 outline some typical operating conditions that may preclude the installation or limit the effectiveness of certain LDS technologies. Regional considerations should also be used in determining whether a specific LDS technology will be transferable or feasible for use on a specific pipeline. A sound understanding of existing and expected pipeline conditions together with LDS system limitations is necessary for the successful implementation of any LDS technology. Advantages and operational situations that should be avoided are presented for each leak detection technology.

4.1.4 Compatibility/System Requirements

The operating requirements of each LDS, including instrumentation, communications, sampling frequency, and controller training are presented under this criterion to enable the potential user to further evaluate whether the LDS is compatible with a specific pipeline system.

4.1.5 Environmental Impacts

Environmental impacts are assessed under the BAT regulations by determining “whether the environmental impacts of each alternative technology, such as air, land, water, energy, and other requirements, may offset any anticipated environmental benefits.” Internally installed LDSs typically do not represent a significant change to the surrounding environment. Externally installed systems may require excavation or other disturbances to the environment surrounding the pipeline system.

4.1.6 Regional Considerations

Regional considerations are key in selecting LDSs for Alaskan pipeline operations. Alaskan operations are characterized by long distances, large and rapid changes in elevation, large changes in throughput due to weather events in production or terminal areas, annual temperature variations of up to 160 °F, and limited ground access along some pipe segments. These regional considerations may be key in the selection of an LDS alternative, its communications system, or both.

Long distance pipelines require multiple pump stations to maintain line pressure. The selected LDS must be capable of highly accurate inventory, or be segmented between pump stations, to compensate for use of surge tanks and operational changes at individual stations.

Elevation changes create pressure differentials within the pipe and, under lower throughput, may cause slack-line conditions to exist in downhill segments. If appropriate, the selected LDS must be able to compensate for large pressure variations (for pressure differential-based systems) or for transient storage terms (for pipeline volume-balance based modeling systems).

Not all pipelines are ground-accessible throughout the year. Therefore, to limit costs, pipelines in such areas should rely on LDSs that do not require frequent maintenance or calibration events.

4.1.7 Field Performance

The evaluation of actual LDS field performance is essential to substantiate vendor claims of system sensitivity, accuracy, reliability, and robustness. Industry references provided by the vendors and ADEC were contacted to verify and comment on the performance of their LDS.

4.1.8 Cost

Vendors were extremely reluctant to provide absolute hardware and software costs for their leak detection systems because there is no way to accurately extrapolate the numbers to a pipeline without knowing its exact configuration. They also indicated that there is a great deal more to the cost of owning an LDS than the bare bones system price (i.e., the relative cost of instruments, maintenance or life cycle costs, and costs associated with adding more lines to the system). For these reasons and unless the vendors provided actual numbers, the costs associated with each technology are discussed only qualitatively. A general LDS pricing discussion is presented in the paragraph below. There are often tradeoffs between the price of an LDS and its performance. Highly effective systems (sensitive, accurate, reliable, and robust) ultimately will cost more to implement and maintain. It is up to the pipeline company to establish pipeline-specific performance standards and weigh the costs and benefits of an LDS.

In general and excluding costs for additional instrumentation and maintenance, installed and tuned software-based volume balance and pressure analysis systems are available for less than $200,000. Ultrasonic volume balance systems typically are more expensive because they require the purchase of vendor-specific clamp-on flow meters at about $35,000 to $40,000 each. Real time transient models run between $200,000 and $1,000,000, depending on pipeline configuration. External liquid-sensing and fiber optics cables are about $5 to $15 per foot installed. Accompanying hardware and software is required for each cable segment at prices between $10,000 and $50,000. Costs for soil gas/tracer sensing technologies are about $15 per probe (a probe needs to be installed about every 20 feet) with additional costs for installing field stations every two miles (approximately $50,000), and a central computer with specialized software ($10,000-$20,000). Acoustic emissions *AE* system can be installed on a single pipeline segment of 200 to 300 feet (i.e., 2 sensor systems with a 2-channel ALM) for $5,000 to $12,000. Each additional segment requires a channel at an added cost of approximately $3,000.

5 REFERENCES

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6 GLOSSARY

Accuracy (Evaluation Criterion): The measure of leak detection system performance related to estimation parameters such as leak flow rate, total volume lost, and leak location. A system that estimates these parameters within an acceptable degree of tolerance, as defined by the pipeline controller/company, is considered to be accurate.

Accuracy (Instrument): The measurement performance of the instrument relative to that of an ideal device.

Alarm: A visual or audible notification to the pipeline operator that an anomaly has been detected that is outside the preset limits.

Algorithm: A mathematical rule or procedure for solving a problem.

Applicability/Availability: A best available technology evaluation criterion. Applicability ensures that any technology selected for use on a crude oil pipeline system was designed for that intended use. Availability refers to the commercial availability of a leak detection system and its components.

Best Available Technology: As defined under 18 AAC 75.990(9), means the best proven technology that satisfies the applicable requirements of 18 AAC 75.425(e)(4) and criteria of 18 AAC 75.445(k).

Bulk Modulus: The bulk modulus of a liquid is the reciprocal of its compressibility.

Compatibility/System Requirements: A best available technology evaluation criterion. The operating requirements of each leak detection system, including instrumentation, communications, sampling frequency, and controller training.

Computational Pipeline Monitoring (CPM): Algorithmic monitoring tools that are used to enhance the abilities of a pipeline controller to recognize anomalies which may be indicative of a product release. Also known as internal leak detection.

Cost: A best available technology evaluation criterion. The hardware and software costs associated with a vendor-specific leak detection system.

Effectiveness: A best available technology evaluation criterion dealing with the performance related aspects of a leak detection system. Effectiveness is evaluated in terms of sensitivity, accuracy, reliability, and robustness.

Environmental Impacts: A best available technology evaluation criterion. As defined in the regulations (18 AAC 75.445(k)), “whether the environmental impacts of each alternative technology, such as air, land, water, energy, and other requirements, may offset any anticipated environmental benefits.”

External Leak Detection System: Externally based methods detect leaking product outside the pipeline and include traditional procedures such as right-of-way inspection by line patrols, as well as technologies like hydrocarbon sensing via fiber optic or dielectric cables.

False Alarms: Transient alarms that are not caused by an actual product release.

Field Performance: A best available technology evaluation criterion. The evaluation of actual field performance to substantiate vendor claims of system sensitivity, accuracy, reliability, and robustness.

Filter: A device or algorithm to remove unwanted components from a process signal.

Flow Meter: Devices installed on pipelines to measure product flow through the line. Several different types of flow meters are used in the industry including orifice plates (differential pressure), turbine, positive displacement, mass flow (Coriolis type), and ultrasonic time-of-flight (clamp-on).

Internal Leak Detection System: Internally based methods use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation. Also known as computational pipeline monitoring.

Line Pack: The actual volume of product in a pipeline segment. It is a function of pipe diameter, wall thickness and material, the thermal expansion coefficient of the pipe material, the reference density of the product, pressure, and temperature.

Master Terminal Unit (MTU): A component of the SCADA system, usually located in the control room, that gathers and displays process data from the field remote terminal Units (RTUs) and programmable logic controllers (PLCs).

Multiphase: The condition where a pipeline contains liquid product, gas-phase product, and water.

Noise: An unwanted component in a process signal or the part of a signal which does not represent the quantity being measured.

Pig: A device designed to move through a pipeline for purposes of cleaning, product separation, or information gathering.

Pipeline Controller: A person who is responsible for the monitoring and direct control of the pipeline.

Polling: A type of SCADA communications protocol in which sequential requests for process data from field units are issued by the master terminal unit (MTU).

Precision: A measure of the smallest change that can be seen in the output of the instrument.

Pressure Analysis: A leak detection method based on the analysis of pipeline pressure variations and the identification of the rarefaction wave produced when product breaches the pipeline wall. Most internal leak detection systems also use pressure analysis to locate leaks.

Pressure Transducer: Instruments installed on pipelines to measure the pressure of the product within the line. Conventional pressure transducers generally are of the electronic sensing type with various means of discerning pressure (piston, diaphragm, strain gauge, piezoelectric sensors, variable capacitance, and variable element). Pipeline pressure is measured by the displacement of these devices in response to fluid pressure and is converted electronically to an appropriate current, voltage, or digital output signal.

Product characteristics: The physical properties of a product as defined by its density, specific weight, pressure, surface tension, bulk modulus of elasticity, vapor pressure, and viscosity.

Programmable Logic Controller (PLC): A SCADA system component, typically installed at a field site, that gathers process data from instruments for transfer to the MTU.

Protocol: The specifications of the messages between remote terminal units (RTUs) or programmable logic controllers (PLCs) and the master terminal unit (MTU).

Rarefaction Wave: Also called an acoustic, negative pressure, or expansion wave. It is the undulation resulting when product breaches the pipeline wall and there is a sudden drop in pressure at the location of the leak followed by rapid line repressurization a few milliseconds later. The resulting low-pressure wave travels at the speed of sound through the liquid away from the leak in both directions.

Real Time Transient Modeling (RTTM): A leak detection method involving the computer simulation of pipeline conditions using advanced fluid mechanics and hydraulic modeling. RTTM software can predict the size and location of leaks by comparing the measured data for a segment of pipeline with the predicted modeled conditions.

Regional Considerations: A best available technology evaluation criterion assessed in terms of Alaskan pipeline operations (i.e., long pipeline distances, large and rapid changes in elevation, energetic submarine/underwater environments, annual temperature variations of up to 160 °F, and limited ground access along some pipe segments).

Reliability: A measure of the ability of a leak detection system to render accurate decisions about the possible existence of a leak on a pipeline.

Remote Terminal Unit (RTU): A SCADA system component, typically installed at a field site, that gathers process data from instruments for transfer to the MTU.

Repeatability: A measure of an instrument's ability to consistently return the same reading for a given set of conditions.

Robustness: A measure of a leak detection system's ability to continue to function and provide useful information, even under changing operating conditions.

SCADA: An acronym for Supervisory Control and Data Acquisition, the technology that makes it possible to remotely monitor and control pipeline facilities.

Segment (of a Pipeline): A pre-defined portion of pipe that has its own unique indivisible identity and is usually bounded by flow measurement and/or pressure transducer instrumentation.

Sensitivity: The composite measure of the size of leak that a system is capable of detecting, and the time required for the system to issue an alarm in the event that a leak of that size should occur

Slack Line: The condition where a pipeline segment is not entirely filled with product or is partly void.

Transferability/Feasibility: A best available technology evaluation criterion requiring a close examination of expected pipeline operating conditions. Pertains to the advantages and operational situations that should be avoided for each leak detection technology.

Transient: Any unsteady flow or pressure condition in a pipeline. Transients typically arise from operations such as valve changes and pump starts or shutdowns. They are also created when a leak occurs on a pipeline. For non-leak events, transients result in line pack changes that must be accounted for in leak detection.

Volume Balance: A leak detection method based on measuring the discrepancy between the incoming (receipt) and outgoing (delivery) product volumes of a particular pipeline segment.

7 VENDOR INDEX

Listed by vendor name in alphabetical order, with leak detection method and system name. Specific product details available on cd-rom from:

[redacted]

1. Acoustic Systems, Inc. - Internal Pressure Analysis (Rarefaction Wave Monitoring) - WaveAlert®
2. Controlotron Corporation - Internal Mass Balance Clamp-On Ultrasonic Flow Meters - System 990LD®
3. DETEX International - Internal Mass Balance Clamp-On Ultrasonic Flow Meters - Series 2000™
4. EFA Technologies Mass Pack - Internal Mass Balance - MassPack™ (part of LeakNet™ package)
5. EFA Technologies PPA - Internal Pressure Analysis (Rarefaction Wave Monitoring) - Pressure Point Analysis™ (Part of LeakNet™ package)
6. EnviroPipe Applications, Inc. - Internal Mass Balance - LEAKTRACK 2000
7. FCI Environmental, Inc. - Fiber Optic Chemical Sensor - PetroSense®
8. LICEnergy, Inc. - Internal Real Time Transient Modeling (RTTM) - Pipeline Leak Detection System (PLDS)
9. Løgstør Rør - External Liquid Sensing Cable - LR-Detector
10. National Environmental Services Co. (NESCO) - External Soil Vapor Detection - Soil Sentry Twelve-XP
11. PermAlert - External Acoustics Emissions - Acoustic Emissions (AE)
12. Physical Acoustics Corporation - External Liquid Sensing Cable - PAL-AT®
13. Raychem Corporation - External Liquid Sensing Cable - TraceTek
14. Siemens AG - External Sensing Tube - LEOS®
15. Simulations Inc. - Internal Real Time Transient Modeling (RTTM) - LEAKWARN
16. Stoner Associates - Internal Real Time Transient Modeling (RTTM) - SPS/Leakfinder
17. Tracer Research Corporation - Internal Pressure Analysis (Rarefaction Wave Monitoring) - LeakLoc®
18. Tracer Research Corporation - External Vapor Sensing Leak Detection System - Tracer Tight®

questions whether Enbridge has complied with the terms of the Easement and with various state and federal laws with respect to its operation of Line 5. This is probably not the place or time to litigate these potential causes of action.

The court should take judicial notice of the fact the Governor of the State of Michigan has appointed a Michigan Pipeline Advisory Board which has just hired contractors to perform a year- long study of the risks and alternatives to Line 5. The Advisory Board will issue its recommendations to the State in late 2017. Either the current Governor or the governor to be elected in November, 2018 will be taking some action on Line 5 which is almost certain to trigger court review. The people of the State of Michigan may also elect to enforce the Easement or seek enforcement of state law with regard to Line 5.

The SACCPJE therefore requests that Paragraph 193 be clarified to make it clear that the Consent Decree will have absolutely no impact on any potential or future litigation involving Enbridge's operation of Line 5.

Respectfully submitted,

Leonard R. Page
Attorney for Straits Area Concerned Citizens for Peace, Justice, and the Environment
P-18584

[redacted]
Cheboygan, Mi [redacted]

Comment 9

To: ENRD, PUBCOMMENT-EES (ENRD)[PENRD3@ENRD.USDOJ.GOV]
From: youneek one
Sent: Sun 8/7/2016 9:56:01 PM
Importance: Normal
Subject: Enbridge Energy Line 3 'replacement'
Received: Sun 8/7/2016 9:58:03 PM
consent_decree_response_8_4_16.pdf

I'm writing to ask that particular attention be paid to a consent decree proposed by Canadian company Enbridge Energy about what they are ca 'replacement' of Line 3 oil pipeline in Minnesota. Reference United States v. Enbridge Energy, Limited Partnership,et al., D.J. Ref No 90-5-1-1- A replacement would occupy the same area and include a decommission of the old line, correct? Enbridge is proposing a different location and promising they won't repair and reuse the old. This indicates that proposed Line #3 is actually a new addition, not a replacement, and thus the could be two lines rather than one.

If there truly IS any urgency as Enbridge implies, the proper action would be for Enbridge to immediately stop using the old line, correct? And the URGENCY to approve a completely new line - in fact, the better it is studied with a complete EIS, the better the chance for the most safe plan to place. (Even the necessity of a new line should be subject to further review. Enbridge themselves have invested billions of dollars in recent yea alternative energy - and perhaps this makes more sense than building MORE lines for oil, especially with the current drops in price and product

Please see the attached copy of a letter for some finer points. This was recently sent to the Minnesota Public Utilities Commission by The Minne For Environmental Advocacy. I believe their points summarize what is most important.

Thank you for your attention to these details, which truly could mean the difference between a thriving future for the people and pristine waters of and an environmental disaster of untold proportion.

Nancy Oldham
[redacted]

Minnesota Center for
Environmental Advocacy

Using law, science, and research to protect Minnesota's environment, its natural resources, and the health of its people.

[redacted]

info@mncenter.org
www.mncenter.org

August 4, 2016

Mr. Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101

VIA ELECTRONIC SERVICE

Re: *In the Matters of the Application of Enbridge Energy, Limited Partnership for a Certificate of Need and Routing Permit for the Line 3 Replacement Project*

MPUC Docket Nos. PL-9/CN-14-916
PL-9/PPL-15-137

Dear Mr. Wolf:

We write to express our concern about Enbridge's apparent effort to use a recent proposed consent decree to leverage the Commission into rushing the Line 3 proposed replacement. In this letter, MCEA and FOH provide the history of the Consent Decree and the reasons why this proposed consent decree is irrelevant to the Commission's schedule for, and final decision on, Line 3.

On July 26, 2010, Enbridge's Line 6B, a 30-inch pipeline carrying crude oil, burst near Marshall, Michigan and spilled over a million gallons of crude oil into the Kalamazoo River. Heavy rains carried the oil at least 35 miles downstream.[1] After the rupture occurred, three shifts of Enbridge employees ignored the alarms and continued to pump oil through the pipeline for 17 hours.[2] The delay resulted in the release of over 1,000,000 gallons of crude oil. The National Transportation Safety Board compared the Enbridge employees' response to the warning signs of the

[1] Details about the spill and spill response as provided by the U.S. Environmental Protection Agency may be found at https://www.epa.gov/enbridge-spill-michigan.
[2] "Enbridge Employees Compared to 'Keystone Cops' in 2010 Kalamazoo River Oil Spill," Michigan Radio, July 10, 2012, available at http://michiganradio.org/post/enbridge-employees-compared-keystone-cops-2010-kalamazoo-river-oil-spill.

rupture to the "Keystone Kops."[3] Enbridge employees twice tried to restart the line, pumping additional oil into the river. The oil saturated surrounding wetlands, and hundreds of local residents were sickened from exposure to toxic components of crude oil.[4] Cleanup costs are estimated at $1.21 billion.[5] Five years after the spill, more than 1 million gallons of oil have been recovered, but some areas will never be cleaned up.

In the wake of this spill, Enbridge has agreed to pay $61 million in civil penalties in a proposed consent decree.[6] However, the proposed consent decree also includes language obligating Enbridge to replace Line 3. It states that "Enbridge shall replace the segment of the Lake head System Line 3 oil transmission pipeline that spans approximately 292 miles from Neche, North Dakota, to Superior, Wisconsin ("Original US Line 3")." It also states that Enbridge "shall complete the replacement of Original US Line 3 and take Original US Line 3 out of service, including depressurization of Original Line 3, as expeditiously as practicable after receiving required regulatory approvals and permits for new Line 3," and that Enbridge "shall seek all approvals necessary for the replacement of Original US Line 3... as expeditiously as practicable."[7]

Enbridge is already using this language to attempt to rush the process, telling media that Enbridge is "hopeful that the settlement will instill a new sense of urgency at all relevant levels of Minnesota government, from the Governor's office to the agencies to the PUC."[8]

The irony of Enbridge attempting to take a consent decree in which it pays millions in civil settlement penalties for damages caused by one of the largest inland oil spills in US history, and using it to leverage the state of Minnesota into hurrying along a new pipeline should not be lost on the Commission, the Department of Commerce, or the Governor's office. The lesson of the Kalamazoo spill and spills across the country is that caution must not be sacrificed in the name of speed. If Line 3 is currently so degraded that it is dangerous to operate, the appropriate action would be to decommission the pipeline to prevent oil spills, not to continue to operate a dangerous pipeline while trying to rush the permitting process for its replacement.

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[3] "Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations." National Transportation Safety Board Office of Public Affairs, July 10, 2012, available at http://www.ntsb.gov/news/press-releases/Pages/PR20120710.aspx.
[4] *Id.*
[5] "New Price Tag for Kalamazoo River Oil Spill Cleanup: Enbridge Says $1.21 Billion," MLive, November 5, 2014, found at http://www.mlive.com/news/grand-rapids/index.ssf/2014/11/2010_oil_spill_cost_enbridge_1.html.
[6] The proposed consent decree also includes $1 million in fines for a spill in Illinois, and $110 million in other fines. https://www.epa.gov/enforcement/enbridge-clean-water-act-settlement
[7] Proposed Consent Decree, p. 25, available at https://www.epa.gov/sites/production/files/2016-07/documents/enbridge-cd.pdf.
[8] "Enbridge Agrees to $177M Settlement for 2010 Oil Pipeline Spills," MPRNews, July 20, 2016, available at https://www.mprnews.org/story/2016/07/20/enbridge-oil-spill-settlement.

We write to provide our own reading of the proposed consent decree. We submit that Enbridge's alleged "urgency" as a result of this proposed consent decree is a self-serving attempt to control a permitting process that is exclusively delegated to state authorities, and should not prompt the state to change its current course on the EIS for Line 3 or the permitting procedures.

First, this is merely a proposed consent decree, not a final one. It is still subject to a comment period and approval by the Department of Justice as well as a federal judge. It is premature at best for Enbridge to use this document for any purpose, except negotiations with the Department of Justice.

Second, the DOJ has carefully crafted the language of this agreement to ensure that it does not infringe on state processes in any way. The proposed consent decree only obligates Enbridge to seek approval for Line 3 replacement, which it has already done, and to replace Line 3 quickly *once it has obtained necessary approvals*. It does not and cannot, by its own terms, influence in any way the ongoing permitting process in our state. It cannot bind the state to act quickly or to approve any permits, for neither the DOJ nor any other federal agency has any authority over crude oil pipeline permitting in Minnesota, and there is no federal judge that can order any changes to the state's ongoing permitting process. The Department of Justice cannot require Minnesota to permit a pipeline, nor does it purport to do so.

Nor could Enbridge agree to such a thing, even if it were proposed. Enbridge cannot agree to a consent decree where performance is out of its control. Enbridge cannot replace Line 3 without the approval of the Public Utilities Commission, regardless of a consent decree.

Perhaps most significantly, this proposed consent decree contemplates something that Enbridge has never disclosed to this Commission—the possibility that Enbridge might decommission the existing Line 3, and then maintain and re-commission it for future use. The proposed consent decree states that Enbridge must provide notice to DOJ if it intends to reuse the existing Line 3 after decommissioning it, and must complete certain testing and repairs before doing so. The consent decree contemplates no such future for Line 6b; it "permanently enjoin[s]" Enbridge from reusing Line 6b for the transport of oil, gas, or other hazardous substance. Enbridge could have agreed to similar language on the old Line 3, but it did not.

The possibility of reuse of the old Line 3 significantly alters the proposed Line 3 project, and how it must be evaluated in an EIS. It raises the possibility that even if Enbridge is able to "replace" Line 3, the new Line 3 will not be a "replacement" at all but an additional pipeline, and Enbridge will continue to use the existing Line 3. If Enbridge does not agree to permanently decommission the old Line 3 as a condition of a "Line 3 replacement," the Commission should treat the proposed "Line 3 Replacement" as a new pipeline that will be additional to, and not in replacement of, existing Enbridge pipeline capacity in the state.[9]

Put simply, if the need to replace Line 3 was so urgent, Enbridge should have planned better, and applied for a replacement earlier. Enbridge cannot use this aging pipeline as an excuse to short-circuit required legal processes in which Minnesotans are entitled to participate, including a full and robust EIS and contested case hearings based on all information included in the EIS. FOH and MCEA acknowledge that Line 3 is aging and may encounter increasing safety problems as it ages, as happens with all infrastructure. But this is not new information. Enbridge chose to apply to build Sandpiper first in November 2013, and delayed its applications on Line 3 until April 2015. Nothing has changed since then, except that Line 3 is a little older. Enbridge's responsibilities toward the existing Line 3 are the same as it would have towards any of its pipelines – to maintain it and ensure its safe operation. The PUC and DOC cannot prevent a recurrence of the Kalamazoo spill by hastening the permitting of the Line 3 replacement; that responsibility lies solely with Enbridge, the pipeline operator. If Line 3 cannot be operated safely, operations on the line must cease.

Every new pipeline in Minnesota poses new risks of a spill, and it is only by sheer luck that Minnesota has not been forced to undergo a cleanup on the same scale as Michigan's. The July 26, 2010 Enbridge pipeline rupture that is subject of this consent decree occurred about 45 miles from Grand Rapids, Michigan. The media has reported that it was the biggest on land oil spill in U.S. history, with 1.1 million gallons leaking from the line. But in fact, the media are wrong. On March 3, 1991, the Lakehead Pipeline, now owned by Enbridge, ruptured only a mile or two from another city called Grand Rapids. This release was 1.7 million gallons near Grand Rapids, Minnesota. The leak occurred only a short distance from the Mississippi River, but it occurred on land and in winter. The cold slowed the oil, which did reach the ice-covered Prairie River not far upstream of the Mississippi. As in Kalamazoo, a delayed response in shutting down the pipeline increased the volume of the spill.[10] But booms placed on the ice stopped the flow, and coupled with the favorable locations and frozen ground, clean-up was relatively easy. This event is only forgotten due to luck. If it had occurred in summer, and closer to the Prairie River, FOH and MCEA doubt that the State of Minnesota would be struggling to make the proper decisions on these new Enbridge projects. If volumes of oil of that magnitude had reached the fast-moving and large Mississippi, oil might have travelled much farther downstream than the 38 miles of the Kalamazoo River in Michigan in 2010.

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[9] Enbridge's Certificate of Need Application is in conflict with the proposed consent decree, as both state that "Enbridge is permanently taking the existing Line 3 out of service once the Project goes into Service." Certificate of Need Application, Line 3 Replacement Project, MPUC Docket No. PL-9/CN-14-916, April 2015 at 11-1. Thus, to be consistent, Enbridge should modify its application or change the proposed consent decree. At a minimum, it owes the Commission an explanation as to why it is seeking to preserve the right to reuse Line 3 in the proposed consent decree, while representing to the Commission that it is planning on permanently abandoning it.

[10] See Lakehead Pipeline Company incident report, available at https://incidentnews.noaa.gov/incident/6793

In sum, nothing in the proposed consent decree should cause Judge O'Reilly, the Department of Commerce or the Public Utilities Commission to rush through the EIS or permitting processes. The hasty construction of a crude oil pipeline only enhances the risk of future spills; it does not reduce it. If Enbridge is permitted to replace Line 3, either in its proposed corridor or elsewhere, Minnesotans will live with this pipeline for 30 to 50 years. A few extra months to ensure that this process is done safely is small in comparison.

Sincerely,

/s/ Kathryn M. Hoffman
Kathryn M. Hoffman
Staff Attorney

KMH/km

Comment 10

To: ENRD, PUBCOMMENT-EES (ENRD)[PENRD3@ENRD.USDOJ.GOV]
From: [redacted]
Sent: Sun 8/7/2016 12:04:14 AM
Importance: Normal
Subject: Enbridge oil spill and fine
Received: Sun 8/7/2016 12:04:18 AM

To the DOJ,

I attended a news conference for the Enbridge Oil Spill Fine at Saylors landing on July 20, 2016 As I listen to Pat Miles, US Attorney for Michigan, and EPA Regional Administrator Robert Kaplan and others talk I heard how Enb was negligent in many different parts of the pipeline management. I also heard how all of the State and Federal organization were praised for the fantastic support in the cleanup effort and how the river is beautiful, healthy and wildlife because of them. As I live on the Kalamazoo River down river about 3.75 miles from the pipeline failure, I give a different view. I have watched and dealt with Enbridge, EPA, DNR, DEQ, Calhoun County Health Departme others during the last 6 years as many of them were in my backyard. I would like to thank the Enbridge personal a contractors that they used for the first class cleanup operation.

In regards to the pipeline operation and pipe failure there are some unanswered questions. There has been no inv with the U.S. Department of Transportation"s Pipelines and Hazardous Materials Safety Administration {PHMSA) National Transportation Safety Board (NTSB) or National Association of Pipleline Safety Representatives (NAPSR These are the Government groups the are responsible for construction, operation, maintenance, inspections and enforcement of regulations. What was their involvement both before and after the spill? If these government group payed for with the taxpayers money to enforce the operation and safety regulations what have they been doing? fines and penalties have been imposed on them? If the EPA and Calhoun County Health Department are respons protecting human health and the environment what were the penalties imposed on them for their neglect of duties had no contact for days and no warnings about the dangers of the oil release. It was 4 days after the spill that we from neighbors about the offer to stay at off site accommodations to avoid possible health issues from the oil fume Many days later it was questionable about the well water contamination that people in the area might be having in homes. It certainly appears that if Enbridge has been found negligent in their operation the investigation that took would have found the the same claims against the many departments and people that were had the responsibility laws and regulations and had some fines and penalties for them.

The government speakers made it very clear that this meeting was for the press and the public should keep quite taxpayers pay their salary and their are suppose to represent the people. They have made no contact with me livi river, anyone in the neighborhood or had any meetings to see the public opinion. They made comments of kayaki the river recently to get their opinion but could not stop to talk to the people or land owners. They had no time for t public and very blunt with the two questions that the public did get to ask. Very rude. At least Enbridge had neighb meetings, community meetings and an help center open for people with questions and concerns.

For the DOJ, this is a complaint about your Enbridge oil spill complaint/suit/case. How can this amount of penalty directed to Enbridge and the government departments mentioned above have no responsibility? Very unfair and o sided. I live on the river, 3.75 miles from the release site. Enbridge was the only representative that contacted us o concerns. No Calhoun county health department, no EPA, no MDEQ, no MDNR. The air samples that were taken taken from the street in front of our house. Our house is 200 feet from the river, it is also 200 feet away from the ro I guess they were more concerned about the people driving down the road then the people living on the river. I thi investigation and fine should have included the people and departments that make and enforce the laws and regu They also neglected their duties. I have received responses from these departments all saying what a wonderful j did and how everything was Enbridge's fault. Tell me why the taxpayer supports these departments that what no responsibility. It is all about money. You place all the fault and fines against Enbridge, that makes the public pay m money, while the taxpayers keep paying for the government departments that are not responsible for anything. Can you tell me how to get a civil suit against those departments.

Lynn Gildea, Marshall Michigan

Comment 11

To: ENRD, PUBCOMMENT-EES (ENRD)[PENRD3@ENRD.USDOJ.GOV]
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From: Claire Wood
Sent: Wed 8/24/2016 6:41:18 PM
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Subject: FLOW's Public Comments to the DEQ and USACE on Enbridge's Joint Application for Anchoring Supports on Line 5
Received: Wed 8/24/2016 6:43:04 PM
FLOW 8-24-16 Final Letter to DEQ USCOE Joint App Enbridge for Supports GLSLA, CWA.pdf
FLOW FINAL Corps Ltr re Anchor Supports (08-22-16).pdf

Dear Mr. Simon and Ms. Kuhn,

Please accept FLOW's submission of public comments on Enbridge's joint application to the DEQ and Corps to Occupy Great Lakes Bottomlands for anchoring supports, No. 2HBVGKO-35JE. Please see the appendices to the letter on FLOW's website: Appendix A and Appendix B.

Respectfully submitted,
Claire Wood, FLOW

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Claire Wood
Program Coordinator
FLOW (For Love Of Water)
[redacted]
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FLOW
FOR LOVE OF WATER

Protecting the Common Waters of the Great Lakes Basin
Through Public Trust Solutions

August 24, 2016

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VIA ELECTRONIC SUBMISSION

RE: PUBLIC COMMENTS ON THE JOINT APPLICATION OF ENBRIDGE ENERGY TO OCCUPY GREAT LAKES BOTTOMLANDS FOR ANCHORING SUPPORTS TO TRANSPORT CRUDE OIL IN LINE 5 PIPELINES IN THE STRAITS OF MACKINAC AND LAKE MICHIGAN [NO. 2HB-VGKO-35JE]

Applicable Laws Include: Great Lakes Submerged Lands Act, MCL 324.32501 et seq., Common Law Public Trust, the Michigan Environmental Protection Act, MCL 324.1701 et seq.; Joint Application with US Army Corps of Engineers, Rivers and Harbors Act, Sec. 10, 33 U.S.C. § 403; Clean Water Act, 33 U.S.C.§ 404.

Dear Michigan Department of Environmental Quality Director Grether, Officials, and Staff:

For Love of Water ("FLOW") is a Michigan nonprofit corporation dedicated to researching, evaluating, and providing sound law and policy to protect the waters of Michigan and the Great Lakes, their bottomlands, aquatic resources, and the public trust in these lands, waters, and their protected public trust uses. With respect to crude oil pipeline transport in the Great Lakes, FLOW has submitted several reports to the Governor, Attorney General, Michigan Department of Environmental Quality ("MDEQ"), Michigan Department of Natural Resources ("MDNR"), the Michigan Petroleum Pipeline Task Force ("Task Force") and Michigan Pipeline Safety Advisory Board ("Advisory Board") on the high risks associated with Line 5, including the segment in the Straits of Mackinac.[1] These reports concluded the following:

(1) the high risk of catastrophic harm from a crude oil release in the Straits and Lake Michigan and Lake Huron is unacceptable;
(2) there are a number of suitable alternatives and capacity (with reasonable adjustments) within the Great Lakes and Midwest existing crude oil pipeline system to meet existing and future demand and needs; and
(3) interim measures should be immediately implemented to remove crude oil transport from Line 5 given the high risk, magnitude of harm, and suitable alternatives.

This letter is submitted as a primary comment on the above-referenced application to address the scope, purpose, laws, rules, and standards that govern the application. It also provides a brief background to place the application in proper context for your consideration and determination required by such laws, rules, and standards. FLOW appreciates the opportunity to submit these initial comments, and reserves the right to submit additional or supplemental comments before August 28, 2016 or in any extended or new public comment time period.

I. LEGAL FRAMEWORK AND BACKGROUND ON PUBLIC TRUST LAWS AND 1953 EASEMENT WITH STATE

Upon joining the Union in 1837, Michigan took title to navigable waters and the lands beneath them in public trust for the benefit of all citizens, as legal beneficiaries of this trust.[2] The public trust includes fish, aquatic resources, and habitat within the boundaries of

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[1] Appendix A: FLOW Composite Report on Line 5 Risks and Recommendations, with Appendices, submitted to Michigan Petroleum Pipeline Task Force (FLOW, Apr. 30, 2015); A Scientific and Legal Policy Report on the Transport of Oil in the Great Lakes: (1) Recommended Actins on The Transport of Oil Through Line 5 under the Straits of Mackinac; (2) Supplemental Comments to the Michigan Petroleum Pipeline Task (FLOW, Sept. 21, 2015); A Report on the Legal and Pipeline Systems Framework for the Alternatives Analysis of the Pipeline Transport of Crude Oil in the Great Lakes Region, Including Line 5 under the Straits of Mackinac, submitted to Michigan Pipeline Advisory Board (FLOW, Dec. 20015).

[2] *Illinois Central R.R. v Illinois*, 146 US 387, 436-37, 453-59 (1892); *Obrecht v National Gypsum Co.*, 361 Mich 399, 412, 414-16 (1960).

the Great Lakes and tributary navigable waters. The public trust protects preferred public trust uses of these waters and lands, including navigation, boating, fishing, swimming, fowling, drinking water, and sustenance dependent on the integrity of these public trust lands and waters. The public trust imposes an affirmative "solemn" and "perpetual" duty on the state, as trustee, to protect and prevent impairment of these public trust uses, lands, and waters.[3] These public trust waters and bottomlands can never be alienated, public control cannot be surrendered, and these waters and their public trust uses must be protected from risk of impairment.[4]

There are only two very narrow exceptions[5] within which the state may authorize a use or occupancy by conveyances, leases, or agreements for public or private use. The state must determine in due recorded form that (1) the purpose is primarily related to the protection and promotion of these public trust interests and uses; and (2) the proposed use or conduct will not likely result in an unacceptable risk of impairment or harm to these public trust waters, bottomlands of public trust uses, now or for future generations.[6] If these standards are not considered, determined, and established, the use can never be authorized. Because the public trust is perpetual in nature, any private use of public trust waters and lands is subject to changes in knowledge, understanding, and new circumstances.[7] In other words, the public trust is an inherent limitation on any use of public trust resources, and a state trustee is never foreclosed from terminating or modifying a use to protect or prevent harm to the public trust resources or their preferred or protected uses.

In 1952, Enbridge Energy, then Lakehead Pipe Line Company ("Lakehead"), wanted to construct a pipeline from Alberta to Sarnia, Ontario. To do so, it considered two routes: (1) south around the bottom of Lake Michigan and across the Lower Peninsula, and (2) through the Upper Peninsula, across the Straits and down through the Lower Peninsula to Port Huron and under the St. Clair River to Sarnia. Lakehead chose the shorter and less expensive 645-mile route traversing the Upper Peninsula, the heart of the Great Lakes, and the Lower Peninsula.[8]

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[3] *Collins v Gerhardt*, 237 Mich 38, 211 NW 115, 118 (1926).
[4] *Obrecht* 361 Mich at 412; *Illinois Central R.R*, 146 US at 436-37.
[5] *Obrecht*, 361 Mich at 412; Great Lakes Submerged Lands Act, §§ 32502, 32503.
[6] *Obrecht* 361 Mich at 412; *Illinois Central R.R.* 146 US at 436-37.
[7] *State v St. Clair Fishing Club*, 127 Mich 580 (1901); *State v Venice of America Land Co*., 125 NW 770 (1910); *Illinois Central R.R.* 146 US at 436-37; *Obrecht* 361 Mich at 412.
[8] Ironically, in 1969, Lakehead obtained state approval to construct another pipeline system around the southern end of Lake Michigan and across the Lower Peninsula known as Line 6B. In 2010, this pipeline ruptured nearly a million gallons of heavy tar sands into the Kalamazoo River, causing the largest and most expensive inland oil spill disaster in U.S. history. Enbridge then took this opportunity to replace Line 6B and doubled its capacity without attracting the same level of scrutiny Keystone XL faced. Charged with the siting and construction of pipelines like the new Line 6B, the Michigan Public Service Commission ("MPSC") quickly determined it was deemed to be in the "public interest" without conducting a comprehensive impact and alternative study to evaluate the entire Lakehead system and the potentially inessential nature of Line 5. MPSC Approves Enbridge Energy Limited Partnership Request to Construct Part of Line 6B Pipeline Along Alternative Route in Marysville September 24, 2013.
http://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-313062--,00.html

In order to build "Line 5," the Attorney General of Michigan advised Lakehead that legislative authority was necessary to obtain an easement from the state to occupy the Straits public trust bottomlands and waters. In less than two months, the legislature passed Public Act 10 of 1953 ("Act 10"), which authorized state agencies to grant public utilities easements to run lines over public lands or in public trust bottomlands and waters of the Great Lakes. Any such easement, if approved, would remain subject to the state's and citizens' public trust in the public trust lands and waters of the Great Lakes. Lakehead also obtained approvals from the Michigan Public Service Commission ("MPSC") to acquire rights of way for the entire 645-mile pipeline across the Upper Peninsula, under the Straits, and to Sarnia.[9]

On April 23, 1953, the Michigan Department of Conservation granted Lakehead an easement to transport 120,000 barrels/day ("bbls/day") of petroleum products in the Straits segment of Line 5 subject to express covenants, conditions, and the public trust.[10] Specifically, the easement recognizes Enbridge's use and operations are subject to Act 10's reservation that the state's bottomlands are "held in trust" and cannot be subordinated in favor of a private concern. The easement also requires that Enbridge exercise the due care of a reasonably prudent person to protect public (public trust lands and waters, public infrastructure) and private property (riparian or other related interests), and uphold a continuing obligation to comply with all federal and state laws.[11] Express conditions include a 75-foot maximum unsupported span requirement and other structural measures to stabilize the two 20-inch pipelines in the Straits segment.

In 1955, the legislature passed the Great Lakes Submerged Lands Act ("GLSLA") to authorize leases or deeds on proper findings for bottomlands previously filled and occupied.[12] The purpose of the GLSLA at the time was to bring these previously filled and occupied bottomlands under control and protection of the state. Subsequently, the GLSLA was amended to allow leases, conveyance or occupancy agreements, and permits for filling, dredging, and other lawful structures; key to all applications was the fundamental requirement that the proposed public or private use would not impair or substantially injure the public trust in the Great Lakes.[13]

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[9] Michigan Public Service Commission, Opinion and Order, In the matter of the Application of Lakehead Pipe Line Company for approval of construction and operation of a common carrier oil pipeline (Case D-3903-53.1, March 31, 1953) http://www.michigan.gov/documents/deq/Appendix_A.3_493982_7.pdf; Act 16, Public Acts 1929, and other siting and police power laws and regulations.

[10] Straits of Mackinac Pipe Line Easement Conservation Commission of the State of Michigan to Lakehead Pipe Line Company, April 23, 1953 (hereinafter 1953 Easement Agreement). http://www.michigan.gov/documents/deq/Appendix_A.1_493978_7.pdf; Today, the public trust lands and waters are controlled or regulated by the Department of Natural Resources and Department of Environmental Quality.

[11] 1953 Easement, Section A.

[12] Now Part 325, NREPA, MCL 324.32501 *et seq.*

[13] *Id.*, *see generally* Bertram C. Frey and Andrew Mutz, *The Public Trust in the Surface Waters and Submerged Lands in the Great Lakes,* 4 U. Mich J. L. Reform 907-993 (2007).

In 1963, the people of Michigan adopted a new constitution. Article 4, Section 52 mandatorily requires the legislature to pass laws that protect the state's paramount concern for the air, water, natural resources, or public trust interest in those resources from pollution or impairment.

In 1970, the legislature passed the Michigan Environmental Protection Act ("MEPA"),[14] which prohibits likely pollution, impairment, or destruction of the air, water, natural resources or the public trust, except where it is considered and determined by a state or local governmental body or court that there exists no feasible and prudent alternative.[15] The MEPA imposes a duty on governmental and private entities to prevent and minimize environmental degradation or impairment of air, water, or natural resources or public trust.[16] In addition, under a separate legal duty, the MEPA applies to state and local governments, and requires them in any permit, licensing or other similar proceeding, such as the GLSLA or siting of pipelines by the MPSC, to consider and determine likely effects and whether there exist alternatives that better comply with the duty to prevent or minimize harm or impairment to air, water, natural resources and the public trust.[17]

III. ENBRIDGE'S PURPOSE AND STRATEGIC EXPANSION OF LINE 5 AND ENTIRE LAKEHEAD SYSTEM

MPSC documents reveal that Line 5 was originally designed for 120,000 bbls/day with the option to increase to 300,000 bbls/day through the addition of 4 pump stations.[18] In 2013, Enbridge invested $100 million to increase capacity and flow volumes to 540,000 bbls/day through 12 pump stations and anti-friction injection facilities—an expansion of 80 percent the original design capacity.[19] Despite a manifold increase from original volume or capacity and expanded use of Line 5, Enbridge applications to the MPSC have characterized the additional approval of pump stations and other equipment as mere maintenance."

Similarly, in the past several years, Enbridge has implemented its plan to greatly expand its crude oil transport system to 800,000 bbls/day from Alberta and North Dakota through its Lakehead System[20] in the Great Lakes and Midwest region of the U.S. Numerous press

[14] Part 17, NREPA, MCL 324.1701 *et seq*.
[15] *Id*., MCL 324.1703(1); MCL 324.1705; *Ray v Mason Co Drain Comm'r*, 393 Mich 294; 224 NW2d 883 (1975); *State Hwy Comm'n v Vanderkloot*, 392 Mich 159; 220 NW2d 416 (1974).
[16] *Id*. *Ray,* 393 Mich at 294.
[17] MCL 324.1705; *Vanderkloot*, 392 Mich at 159; *Buggs v. Michigan Public Service Comm'n,* 2015 WL 15975 (Mich Ct. App, Jan. 13, 2015)(*unpublished*) (Court ruled that the MPSC failed to sufficiently consider environmental impacts and feasible and prudent alternatives to a proposed pipeline as required by the Michigan Environmental Protection Act, MCL 324.1701 *et seq*).
[18] *See* MPSC Opinion and Order, p. 6, March 31, 1953.
[19] Appendix 2A, pp. 1-6, FLOW Report, Sept. 17, 2015.
[20] "Enbridge's Lakehead Pipeline System ("Lakehead System") includes a network of pipelines that are grouped within right-of-ways that collectively span 1,900 miles from the international border near Neche, North Dakota to delivery points in the Midwest, New York, and Ontario. The products transported by these pipelines allegedly include natural gas liquids and a variety of light and heavy crude oils." The Lakehead System is the part of Enbridge's larger Mainline System with more than 3,000 miles of pipeline corridors in the United States and Canada and is the single largest conduit

releases, news reports, articles, and Enbridge applications to MPSC, and other agencies, and MPSC records, findings, and decisions show a massive expansion through a multi-billion dollar investment to increase capacity through changes to its pipeline infrastructure.[21] For example, after the Line 6B disaster in 2010, Enbridge filed a number of applications to the MPSC to add a new replacement Line 6B parallel to the failed line based on a stated purpose of "preventive maintenance." In fact, the new Line 6B has doubled the capacity for transport of light and heavy crude up to 800,000 bbls/day,[22] making Line 5 inessential.[23] To date, the MPSC has never considered or determined the environmental impacts and feasible and prudent alternative pipeline system and adjustments of this massive expansion in either Line 5 or Line 6B.

In effect, as opposition to the north-south route of Keystone XL in the West mounted, Enbridge expanded its own pipeline system and Michigan and the Great Lakes region have ended up with its own "Great Lakes XL" crude oil pipeline,[24] without full disclosure and consideration of purpose, impacts, and alternatives as required by law and regulation.

IV. Enbridge's Chronic Violations of the Easement's Maximum Unsupported Span Provision and Current 2016 Application Seeking Additional Supports in the Straits[25]

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of liquid petroleum into the United States, delivering on-average 1.7 million barrels of oil into the U.S. each day – a figure that accounts for 23% of the U.S. crude oil imports. *See* USEPA v Enbridge Energy LP, Civil Action No. 1:16-cv-914, Proposed Consent Decree, (July 20, 2016), pp 191-193, 207.https://www.epa.gov/sites/production/files/2016-07/documents/enbridge-cd.pdf

[21] *See the following documents, which are hereby incorporated by reference:* Enbridge Energy Partners Announces Major Expansions of Its Lakehead System (May 15, 2012) http://www.marketwired.com/press-release/enbridge-energy-partners-announces-major-expansions-of-its-lakehead-system-nyse-eep-1658358.htm; Application for Enbridge Energy 2012 for Amendment to the August 3, 2009 Presidential Permit for Line 67 to Increase Operational Capacity of Pipeline Facilities http://www.state.gov/e/enr/applicant/applicants/202433.htm; In re Enbridge Energy, Limited Partnership Application Case No. U-17020, Pre-Filed Direct Testimony of Mark Sitek And Exhibits, pp. 6-7, 12, 20-21, 25 https://efile.mpsc.state.mi.us/efile/docs/17020/0010.pdf; MPSC Approves Enbridge Energy Crude Oil and Petroleum Pipeline Running Through 10 Michigan Counties (Jan. 31, 2013) http://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-294097--,00.html; MPSC Approves Enbridge Energy Limited Partnership Request to Construct Part of Line 6B Pipeline Along Alternative Route in Marysville (Sept. 24, 2013) http://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-313062--,00.html

[22] FLOW Sept. Report, text, I.i.(i), Appendix 2A, 1-6; Appendix 2B, 2-3,

[23] In re Enbridge Energy, Limited Partnership Application Case No. U-17020, Pre-Filed Direct Testimony of Mark Sitek And Exhibits, p 25. https://efile.mpsc.state.mi.us/efile/docs/17020/0010.pdf.

[24] *See* Sierra Club. *Enbridge Over Troubled Water: The Enbridge GXL System's Threat to the Great Lakes.* February 2016. https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/Enbridge%20Over%20Troubled%20Water%20Report.pdf

[25] A more detailed technical and engineering analysis on this issue will be provided in subsequent or additional comments.

Section A (10) of the easement provides that: "The maximum span or length of pipe unsupported shall not exceed 75 feet." This specific engineering requirement was critical to ensuring that these heavy steel twin 20-inch underwater pipelines would be adequately supported both to withstand the currents of the Straits and to prevent collapse from gravitational force.

Dating back to at least 1963, however, sections of Line 5 under the Straits have not had the required support structures demanded by the express terms of the easement, according to Enbridge's 2014 submission to the State of Michigan.[26]

Table 2 ROV Inspection and Span Support Installation History of Line 5 Straits of Mackinac

Year of ROV Inspection	Follow up Actions (Anchor Support Installation)	Type of Support Installed
1963	None	
1972	None	
1975	3	Grout Bags
1979	None	
1982	None	
1987	7	Grout Bags
1989	None	
1990	None	
1992	6	Grout Bags
1997	None	
2001	8	Grout Bags and mechanical support
2003	16	Mechanical Screw Anchors
2004	16	Mechanical Screw Anchors
2005	14	Mechanical Screw Anchors
2006	12	Mechanical Screw Anchors
2007	None	
2010	7	Mechanical Screw Anchors
2012	17	Mechanical Screw Anchors

[26] Enclosure to June 27, 2014 Letter To Hon. Schuette & Hon. Wyant Responses to Questions and Requests for Information Regarding the Straits Pipelines, Table 2 ROV inspection and span support installation history of Line 5 Straits of Mackinac p. 9 http://mediad.publicbroadcasting.net/p/michigan/files/201410/Attachment_to_Response_letter_State_of_Michigan_Final.pdf

While the full history of Line 5's support structures is not entirely known, it is clear from publically available information that Enbridge has struggled to address this chronic engineering issue for decades due to the powerful and unpredictable nature of the currents in the Straits of Mackinac. As a result, Enbridge has been out of compliance with the easement's 75-foot maximum unsupported span requirement repeatedly[27] and placed the public trust waters and bottomlands at high risk, yet has only recently admitted to violating this easement provision in 2014 and again in 2016 following their bi-annual underwater inspections.

Since 2001, as Enbridge's Table 2 reveals, the company has attempted to correct these violations by adding mechanical screw anchors to the bottomlands of the lake bed. In 2001 Enbridge, in what it characterized as an "emergency," applied for a joint MDEQ and Corps permit under the GLSLA and Rivers and Harbors Act ("RHA")/Clean Water Act ("CWA") "to provide support underneath our pipelines in sections where the pipeline shows spans unsupported over too great a distance."[28] Ever since then Enbridge has repeatedly continued to apply for "maintenance" permits under the GLSLA to install more screw anchor structures on the bottomlands of the Straits,[29] but has not completed the process as evidenced by the pending permit application before the MDEQ and the Corps.

Enbridge's most significant attempts to stabilize this underwater pipeline infrastructure took place in 2014 when the state and public became aware of Enbridge's Line 5 crude oil pipeline located in the Straits and Great Lakes. Governor Snyder formed the Michigan Petroleum Pipeline Task Force in 2014. Although the Task Force did not issue its report until the summer of 2015, the MDEQ issued Enbridge a GLSLA permit in July 2014 for an additional 40 screw anchor supports for the pipelines in the Straits; the stated purpose for these added improvements occupying public trust bottomlands was again "maintenance." By claiming this narrowly defined purpose, Enbridge avoided comprehensive review of impacts and alternatives associated with its concurrent 80 percent increase of crude oil transport in Line 5 and 10 percent increase in pressure. Although the MDEQ could have approved temporary or conditional emergency permits and demanded a comprehensive review of potential or likely impacts and alternatives to the expansion of Line 5,[30] the department did not do so.

Following the completion of these additional 40 anchors in 2014, Enbridge represented to the State of Michigan that its "predictive maintenance model . . . has confirmed that pipeline spans will not exceed 75 feet."[31]

On July 20, 2016, the U.S. Environmental Protection Agency ("USEPA") and the Department of Justice ("DOJ") filed a proposed Consent Decree to settle Enbridge's case

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[27] See Appendix B.
[28] Oil & Water Don't Mix Campaign letter to Governor Snyder, Attorney General Bill Schuette et al. (July 1, 2014) http://flowforwater.org/wp-content/uploads/2014/06/2014-07-01-FINAL-Line-5-Governor-Ltr-Sign-On.pdf (pp. 3-4, Exhibit 4).
[29] *Id.* p. 4, Exhibit 5.
[30] MCL 324.32514(2).
[31] Letter from Enbridge to State of Michigan dated November 19, 2014. http://www.michigan.gov/documents/deq/Appendix_B.4_493991_7.pdf

for civil penalties and other relief for CWA violations arising out of the rupture of its Line 6B in 2010. As part of the decree, measures were added to Enbridge's entire Lakehead System, including 19 more anchor supports in the Straits for Line 5. However, the Consent Decree has been noticed for public comment as required by law and has not been approved by the federal district court; moreover, until approved, USEPA can withdraw from any or all of the decree.[32] Significantly, the decree states that it does not affect the requirement for Enbridge to comply with all state and other federal laws and regulations.[33]

On July 26, 2016, Enbridge filed a joint permit application to the MDEQ and the Corps to install up to 19 additional screw anchor supports; the application stated: "Four of the nineteen anchor locations are required per the...Easement, the remaining fifteen anchor locations are being installed for *preventative maintenance*."[34] Enbridge concludes that the impact of each anchor support will be "minimal" or none,[35] and that doing nothing "presents a future risk to the pipeline and is not a viable option."[36] For the reasons described below, this is not factually or legally accurate.

On August 3, 2016, Michigan's Attorney General, MDEQ Director, and MDNR Director then sent a demand letter to Enbridge to cure violation of the 1953 Easement for failure to provide, at a minimum, supports every 75-feet along the pipelines. In addition, the state demanded that Enbridge explain within 14 days how and why the predictive maintenance model had failed. It is unlikely that Enbridge can actually provide a reliable model that can predict "washouts" along the pipeline. As recently as 2010, Enbridge admitted to MDEQ: "we do not have the future structure locations determined at this point," "nor the scope of the projects to come…"[37]

A review of Enbridge's permitting history demonstrates that the company was fully aware of its planned major expansion of crude oil pipeline transport in Michigan, and that Enbridge has circumvented full review under the GLSLA and public trust by characterizing these new support structures and its expanded use of Line 5 as mere "maintenance." In reviewing Enbridge's permit applications (past and present) for these new structures and expanded use, the MDEQ must require Enbridge to complete a GLSLA application for Line 5, with public notice, hearings, full and careful review, and due findings and determinations regarding impacts and alternatives in compliance with the statute and public trust law. Moreover, the applicant has not submitted the required approvals or consent from both local units of governments and adjacent landowners as required by MCL 325.32504(2). If Enbridge does not satisfy these requirements, the application is not

[32] USEPA v Enbridge Energy LP, Civil Action No. 1:16-cv-914, Proposed Consent Decree, (July 20, 2016), pp 191-193, 207.
[33] *Id*.
[34] *Id*.; Attorney General et al. letter, Aug 3, 2016.
[35] Sec. 4, Project Description, Enbridge Application, p. 1.
[36] *Id*.
[37] *See* Oil & Water Don't Mix Campaign letter to Governor Snyder, Attorney General Bill Schuette et al. (July 1, 2014) http://flowforwater.org/wp-content/uploads/2014/06/2014-07-01-FINAL-Line-5-Governor-Ltr-Sign-On.pdf fn 6 (Email from Enbridge Jacob Jorgenson to Scott Rasmussen (DEQ) and Gina Nathan (ACE), Nov. 18, 2010).

administratively complete for proper review and decision, and accordingly, MDEQ cannot authorize or approve the application.

V. PROPER LEGAL SCOPE AND PURPOSE DEMAND FULL REVIEW OF IMPACTS AND ALTERNATIVES FOR ENBRIDGE APPLICATION

Enbridge's application and supporting documents avoid the proper scope and review required by law. A hard look at the true purpose of Enbridge's actions and intent to massively expand capacity throughout its existing Great Lakes pipeline system is warranted.

Beyond the 1953 Easement and the self-serving "maintenance" strategy of Enbridge, there is an overarching legal duty of the MDEQ and state officials to protect the Great Lakes, including the public trust and environment. This duty arises out of the GLSLA, the MEPA, and common law of public trust, and requires a comprehensive review of the overall purpose and expansion of Enbridge in Michigan, and specifically the Straits and waters and bottomlands of the Great Lakes. As noted above, the public trust and duties under the MEPA are continuing and perpetual. The 1953 Easement is by its terms subject to public trust and state laws like the GLSLA and the MEPA, as well as federal laws and regulations, like the CWA, RHA, and the National Environmental Policy Act ("NEPA") (with the environmental impact and alternative process).[38] In each GLSLA application for a permit, lease, deed, or agreement, the MDEQ shall not grant approval unless it has "determined *both* of the following:

(a) That the adverse effects to the environment, public trust, and riparian interests of adjacent owners are minimal and will be mitigated to the extent possible;
(b) That there *is no feasible and prudent alternative* to the applicant's proposed activity consistent with the reasonable requirements of the public health, safety and welfare."[39]

In other words, the standards for purpose, public necessity, and public trust in the GLSLA and under public trust law demand a comprehensive review of environmental impact, public trust resources impact, and use impact, and alternatives or options assessments and determinations.[40] Thus, the state cannot allow the status quo in the use of Line 5 on public trust bottomlands or overlying waters *unless* Enbridge can demonstrate – as required by the easement, the GLSLA, public trust state laws, and federal laws – that these 4.09 mile submerged pipelines will not likely harm public trust waters, the ecosystem, fishing, commerce, navigation, recreation, drinking water and other uses that depend on these waters.

In addition, MEPA requires a consideration of such effects and whether there exist "feasible and prudent alternatives."[41] Moreover, MEPA requires compliance by an agency

[38] 42 U.S.C. 4332(2)(C).
[39] R 322.1015 (emphasis added).
[40] *Obrecht*, 361 Mich at 412
[41] MEPA, Section 1705; *Vanderkloot*, 392 Mich at 159; *Buggs* 2015 WL at 15975; *Genesco v MDEQ*, 250 Mich App 45 (2002).

with the affirmative duty to prevent and minimize impairment or pollution,[42] and an independent duty to consider likely environmental impacts and alternatives to the fundamental purpose for which the project is being implemented.

The Task Force report recommends two separate, independent, and "comprehensive" analyses on Line 5's risks and alternatives.[43] The law of impact and alternative statements and assessments demands comprehensive and full studies, including a proper scope and purpose that addresses all potential impacts and all alternatives such as other pipeline routes and adjustments within the overall pipeline system in question.[44]

The Advisory Board is providing oversight of these studies, which are being done by contract with the state through the Attorney General's Office (risk study) and the MDEQ (alternatives study). This current state-led process slated for completion in late 2017/early 2018 is neither under rule of law nor complies with the GLSLA, public trust, MEPA, or NEPA impact and alternative assessment requirements. These studies, therefore, should be coordinated with the MDEQ's permit application assessments as required under rule of law.

By the express terms of the easement and privilege to use public trust bottomlands and waters of Michigan, Enbridge's easement interest is subordinate[45] to and must comply with the legal agreement along with all federal and state laws. In addition, Enbridge is subject to state laws authorizing the company to locate and operate crude oil pipelines in Michigan. Accordingly, it is up to the state to fully apply the laws within the scope and purpose that addresses the full risks and alternatives concerning transport of crude oil in Michigan.

The time has come for the MDEQ and State of Michigan to consider and determine the purpose and scope of impact and alternative review, assessments and decisions. Under the GLSLA, MEPA, CWA, RHA, the MDEQ, MDNR, and state, and the Corps are required to and should do so. Anything short of this reasonable prudent approach breaches the public trust, the GLSLA, MEPA, CWA, and NEPA.

VI. CONCLUSION

Based on the above, we object to Enbridge's current application. It does not state the basic or fundamental purpose or activity regarding the expansion of Line 5, does not contain an adequate study and assessment of potential adverse effects of Line 5 and the Straits section, does not address alternative pipeline routes, adjustments to capacity or the system, and violates the express requirements of the GLSLA, MEPA, public trust, and CWA and RHA.

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[42] *Id.*; *Ray,* 393 Mich at 294.
[43] Task Force Report, p 47.
[44] *See* FLOW Alternatives Legal Framework report to Michigan Pipeline Advisory Board, Dec. 2016, at pp. 10-12, supra fn 1; *see* also NEPA, 40 CFR 1502.1, calling for "full" discussion of alternatives; 40 CFR 1502.14 for "rigorous" exploration of alternatives.
[45] *State v St. Clair Fishing Club*, 127 Mich 580 (1901); *State v Venice of America Land Co*., 125 NW 770 (1910); *Illinois Central R.R.* 146 US at 436-37; *Obrecht* 361 Mich at 412.

The MDEQ, state, and the Corps are requested to exercise their legal authority to review the overall Enbridge project purpose, not the "toe of the tiger." Such review demands both the state and federal agencies to conduct a full and comprehensive environmental impact statement and alternatives assessment under Michigan and federal law as described above.

In addition, the MDEQ and the Corps are requested to set the application for public hearing as provided in Section 32514 of the GLSLA and R 322.1017 (Rule 17), along with proper notice and additional time for public comment.

Finally, this case presents a high risk of substantial likely impairment and safety concerns about the integrity of Enbridge's twin underwater pipelines, as well as the mandatory state legal duties to protect health, safety, and welfare; these dual goals are not inconsistent and therefore warrant interim or temporary conditional measures to be ordered, including shutting down temporarily the transport of oil in Line 5. In fact, it would be prudent to do so given the established high and unacceptable risk of harm to the Great Lakes and economy endangered by Line 5, and available alternatives, including the doubled capacity to 800,000 bbls/day in the new Line 6B. In the alternative, the statute authorizes the agency to issue conditional emergency permits to protect the public health, safety, welfare and the environment. Accordingly, the MDEQ could conditionally approve – without prejudice to the State's comprehensive review and final decision – the four anchor supports in violation by the easement as identified by the Attorney General et al. in the August 3, 2016 letter.[46] Such conditional permit can state that it does not affect or foreclose any decision on the record of the application within the authority granted by statute, regulation, or common law.

Once again, we appreciate the effort moving forward to comply with these laws and the public trust duties and principles that apply. Should you want to discuss further or have any questions, we are willing to meet with you at your earliest convenience.

Thank you.

Sincerely yours,

[redacted]

James M. Olson
President

[redacted]

Elizabeth R. Kirkwood
Executive Director

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[46] The GLSLA expressly authorizes "conditional permits" or actions in "emergency" "to protect public property or public health, safety or welfare." MCL 324.32514(2). There is ample authority for MDEQ to take any action on a temporary emergency basis to protect health and safety to suspend transport of crude oil in light of the risks and dangers and lack of full understanding of the currents and other physical circumstances giving rise to such pipeline risk of failure.

CC: Charles Simon, Chief, Regulatory Office, Corps Detroit District
Kerrie Kuhn, Chief, Permits, Corps Detroit District
Michigan Governor Rick Snyder
Michigan Attorney General Bill Schuette
MDNR Director Keith Creagh
U.S. Senator and Hon. Gary Peters
U.S. Senator and Hon. Debbie Stabenow

FLOW
FOR LOVE OF WATER

Protecting the Common Waters of the Great Lakes Basin
Through Public Trust Solutions

August 24, 2016

Mr. Charles Simon, Chief, Regulatory Office, Corps Detroit District
U.S. Army Corps of Engineers
477 Michigan Avenue, Room 603
Detroit, MI 48226-2550

Ms. Kerrie Kuhn, Chief, Permits, Corps Detroit District
U.S. Army Corps of Engineers
477 Michigan Avenue, Room 603
Detroit, MI 48226-2550

RE: PUBLIC COMMENTS ON THE JOINT APPLICATION OF ENBRIDGE ENERGY TO OCCUPY GREAT LAKES BOTTOMLANDS FOR ANCHORING SUPPORTS TO TRANSPORT CRUDE OIL IN LINE 5 PIPELINES IN THE STRAITS OF MACKINAC AND LAKE MICHIGAN [NO. 2HB-VGKO-35JE]

Applicable Laws Include: Great Lakes Submerged Lands Act, MCL 324.32501 et seq., Common Law Public Trust, the Michigan Environmental Protection Act, MCL 324.1701 et seq.; Joint Application with US Army Corps of Engineers, Rivers and Harbors Act, Sec. 10, 33 U.S.C. § 403; Clean Water Act, 33 U.S.C.§ 404.

Dear Mr. Simon:

For Love of Water ("FLOW") is a Michigan nonprofit corporation dedicated is researching, evaluating, and providing sound law and policy to protect the waters of Michigan and the Great Lakes, their bottomlands, aquatic resources, and the public trust in these lands, waters, and their protected public trust uses.

We submit the enclosed Public Comment filed with the Michigan Department of Environmental Quality on the Enbridge Joint Application for Anchor Supports for Line 5 in Lake Michigan, Straits of Mackinac. Please include the factual and legal analysis and comments in the U.S. Army Corps of Engineers ("Corps") record for its review of this matter under the Rivers and Harbors Act ("RHA") and Clean Water Act ("CWA") and their respective applicable rules.

In addition, we incorporate by reference the comment and requests submitted by the Grand Traverse Band of Ottawa and Chippewa Indians on August 23, 2016.

Based on these facts and analysis, it is our conclusion that the Enbridge Joint Application does not qualify for a Nation-wide Categorical permit. It is abundantly clear on this record and other applications and documentation that the scope and purpose of these supports includes Enbridge's on-going implementation of its expansion plans and basic purpose to double the capacity of its Lakehead System to shippers' destinations in Canada and the United States. When properly characterized, it is also clear that Enbridge has and intends to build its own "Great Lakes XL" through the Great Lakes Basin. To date, Enbridge has done so through an unduly narrow representation of a segment-by-segment pipeline approach as pure "maintenance," when in fact it is to expand and double the entire design capacity and flow through of its Lakehead System.

Accordingly, you are requested to subject the application to the full and comprehensive review required by the RHA, CWA, their respective rules, and the environmental impact and alternative statement required by the National Environmental Policy Act, 42 U.S.C. 4332(C) and its applicable rules.

Thank you to you and your staff for your serious consideration of this letter and attached public comments. If you have any questions or would like to discuss the above, please contact us. We are willing to provide additional information by phone, email, or personal meeting.

Sincerely yours,

[redacted]

James M. Olson
President

[redacted]

Elizabeth R. Kirkwood
Executive Director

CC: Michigan Governor Rick Snyder
Michigan Attorney General Bill Schuette
MDEQ Director Heidi Grether
MDNR Director Keith Creagh
U.S. Senator and Hon. Gary Peters
U.S. Senator and Hon. Debbie Stabenow