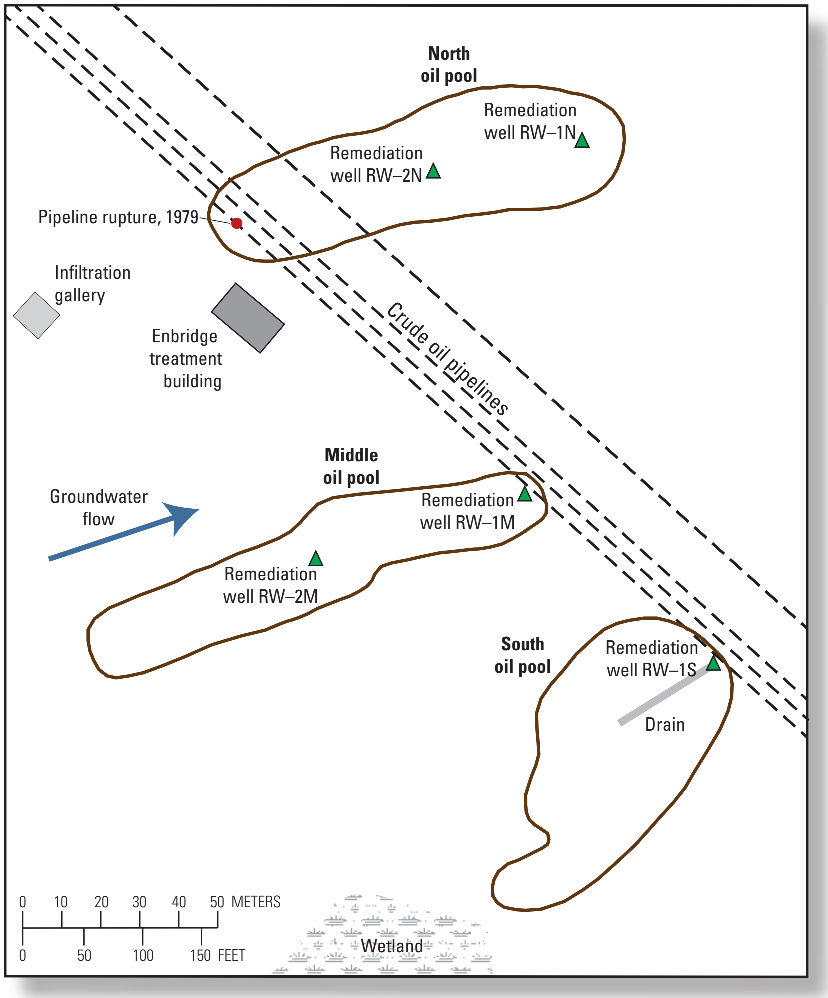
Toxic Substances Hydrology Program

Effects of a Crude-Oil Recovery Remediation System Operated 1999–2003 on Groundwater Plumes and Unsaturated-Zone Vapor Concentrations at a Crude-Oil Spill Site Near Bemidji, Minnesota



Scientific Investigations Report 2020–5111

U.S. Department of the Interior
U.S. Geological Survey

Cover figure: Features associated with the 1999–2003 crude oil remediation at the National Crude Oil Spill Fate and Natural Attenuation Research site near Bemidji, Minnesota.

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DAVID BERNHARDT, Secretary

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James F. Reilly II, Director

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We thank the numerous U.S. Geological Survey (USGS) employees who contributed their assistance with technical consultation and various analyses and data collection associated with this report. We thank in particular our USGS colleagues in the Upper Midwest Water Science Center in Minnesota for sample collection and analytical support. The authors thank USGS technical reviewers Ean Warren and Melinda Erickson for providing valuable comments that substantially improved this report. This research was supported primarily through the USGS Toxic Substances Hydrology Program with additional support through the USGS National Research Program.

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Conversion Factors

International System of Units to U.S. customary units

Multiply	By	To obtain
	Length	
centimeter (cm)	0.3937	inch (in.)
meter (m)	3.281	foot (ft)
meter (m)	1.094	yard (yd)
kilometer (km)	0.6214	mile (mi)
	Area	
square meter (m^2)	0.0002471	acre
square meter (m^2)	10.76	square foot (ft^2)
	Volume	
milliliter (mL)	0.033814	ounce, fluid (fl. oz)
liter (L)	33.81402	ounce, fluid (fl. oz)
liter (L)	2.113	pint (pt)
liter (L)	1.057	quart (qt)
liter (L)	0.2642	gallon (gal)
liter (L)	61.02	cubic inch (in^3)
	Flow rate	
cubic meter per year (m^3/yr)	0.000811	acre-foot per year (acre-ft/yr)
meter per day (m/d)	3.281	foot per day (ft/d)
meter per year (m/yr)	3.281	foot per year ft/yr)

Multiply	By	To obtain
	Flow rate—Continued	
liter per minute (L/min)	0.264172	gallon per minute (gal/min)
liter per day (L/d)	0.264172	gallon per day (gal/d)
	Transmissivity	
meter squared per second (m^2/s)	10.76	foot squared per second (ft^2/s)

U.S. customary units to International System of Units

Multiply	By	To obtain
	Length	
mile (mi)	1.609	kilometer (km)

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as follows:

$$°F=(1.8\times°C)+32$$

Datum

Vertical coordinate information is referenced to the North American Vertical Datum of 1988 (NAVD 88).

Supplemental Information

Specific conductance is given in microsiemens per centimeter at 25 degrees Celsius (µS/cm at 25 °C).

Concentrations of chemical constituents in water are given in either milligrams per liter (mg/L) or micrograms per liter (µg/L).

Abbreviations

BTEX	benzene, toluene, ethylbenzene, and xylene
GC	gas chromatograph
LNAPL	light nonaqueous phase liquid
Lo	total volume of oil per unit area
L_{rec}	recoverable oil volume per unit area
NREC	National Resources Engineering Company
NWIS	National Water Information System
PVC	polyvinyl chloride
S_{or}	residual oil saturation
USGS	U.S. Geological Survey
V_{rec}	recoverable oil volume

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Abstract

A crude-oil spill occurred in 1979 when a pipeline burst near Bemidji, Minnesota. More than 70 percent of the 1.7 million liters of spilled crude oil was removed shortly thereafter. In response to a requirement by the State regulatory agency to remove the remaining crude to a sheen in all wells, in 1998, the pipeline company installed a dual-pump recovery system at the site. This additional remediation from 1999 to 2003 resulted in removal of about 115,000 liters of crude oil, representing between 36 and 41 percent of the volume of oil (281,000–317,000 liters) estimated to be present in 1998. Effects of the 1999–2003 remediation on groundwater plumes and unsaturated-zone vapor concentrations were evaluated by the U.S. Geological Survey using several methods including measurements of oil thicknesses in wells; field water-quality properties of dissolved oxygen, specific conductance, temperature, and pH in groundwater; and vapor concentrations of methane, carbon dioxide, nitrogen, and oxygen in the unsaturated zone.

Although the recovery system decreased oil thicknesses near the remediation wells, average oil thicknesses measured in all wells at the site were not reduced substantially. Dissolved oxygen and specific conductance measurements indicate that a secondary plume was created during the remediation, caused by the disposal of pumped water from the remediation wells in an upgradient infiltration gallery. This plume expanded rapidly immediately after the start of the remediation in 1999, resulting in expansion of the anoxic zone of groundwater upgradient and beneath the existing natural attenuation plume. Beginning in 2000–1, for example, specific conductance concentrations noticeably increased in many wells at the north oil pool from about 400 to more than 700 microsiemens per centimeter. The rapid expansion of the anoxic and elevated specific conductance plume indicates that the remediation contributed substantial amounts of biodegradable dissolved organic carbon to groundwater through the infiltration gallery. The trends in vapor data collected before, during, and after the remediation generally support the research hypothesis that crude-oil removal would have an insignificant effect on vapor concentrations in the unsaturated zone. Although there were some small changes in the concentration of methane, carbon dioxide, nitrogen, and oxygen in the unsaturated zone, these changes were not coincident with the beginning or cessation of the remediation and are therefore thought to be the result of other factors affecting biodegradation rates. A decrease in methane concentrations in one representative well, for example, is thought to be the result of reduced rates of biodegradation and methane production from the increasingly more weathered crude oil. Oil-phase recovery at this site was determined to be challenging and resulted in considerable volumes of mobile and entrapped oil remaining in the subsurface despite remediation efforts.

Introduction

Although the average annual number of crude-oil spills from pipelines decreased from 4.5 to 1.5 releases per year per 1,000 miles (1,600 kilometers [km]) from 1999–2001 to 2007–9, the total amount of oil released annually (about 111,000 liters [L] per 1,600 km) is substantial (Trench, 2011). According to the U.S. Pipeline and Hazardous Materials Safety Administration (https://www.phmsa.dot.gov/, accessed on June 14, 2020), since 1986, there have been nearly 8,000 significant pipeline incidents (nearly 300 per year on average), resulting in more than 500 deaths, more than 2,300 injuries, and nearly $7 billion in damage. Since 1986, pipeline accidents have spilled an average of 288,000 L of hazardous liquids per year. Because the United States has more than 240,000 km of oil pipeline (Trench, 2003), there is a continued risk to the environment.

Remediation of crude oil is difficult because of sorption and entrapment of the oil in the unsaturated zone. Crude oil retained in the unsaturated zone and associated with the water-table capillary zone is not typically recoverable (Testa and Winegardner, 2000). Spilled crude oil does not float on the water table where it can be easily removed (Farr and others, 1990; Lenhard and Parker, 1990; Huntley and others, 1994a; Lundegard and Mudford, 1998; Charbeneau, 2000, 2003; American Petroleum Institute, 2004; Charbeneau, 2007). Direct recovery rates from pipeline spills vary widely. Based on case studies from pipeline releases across the country during 1997–2001, and data collected from the U.S. Office of Pipeline Safety, an average of 42 percent of the spilled oil was recovered (Trench, 2003). When remediation is attempted, simple and readily available methods are needed to evaluate its effectiveness.

Published, peer-reviewed evaluations of the effects of crude-oil remediation on oil thicknesses; field water-quality properties of dissolved oxygen, specific conductance, temperature, and pH in groundwater; and vapor concentrations are limited. Most of the case studies of the recovery of light nonaqueous phase liquids (LNAPLs) have been documented in consulting reports (for example, U.S. Environmental Protection Agency, 2005). Evaluation of free-phase recovery of crude oil in Araucaria, Brazil, was documented in a conference proceeding by Caicedo and others (2003). Abdul (1992) determined that LNAPL thicknesses did not vary significantly within 1 meter (m) of a dual-pump remediation well during an 829-day period when the remediation was monitored. On the other hand, a study by the U.S. Environmental Protection Agency (2005) determined that LNAPL remediation reduced crude-oil thicknesses by as much as 83 percent at some spill sites. None of the previously documented remediation studies, however, provided a long-term (20 or more year) evaluation of crude-oil remediation performances.

A long-term (20+ year), interdisciplinary research project was established by the U.S. Geological Survey (USGS) at a site near Bemidji, Minnesota, in 1983 that provides for long-term evaluation of hydrocarbon fate and remediation performances following a 1979 crude-oil spill when a pipeline burst. More than 70 percent of the 1.7 million L of spilled crude oil was removed shortly thereafter. In response to a requirement in 1997 by the Minnesota Pollution Control Agency to remove the remaining crude to a sheen in all wells, the pipeline company installed a dual-pump recovery system at the site in 1998. This additional remediation from 1999 to 2003 resulted in removal of about 115,000 L of crude oil, representing between 36 and 41 percent of the volume of oil (281,000–317,000 L) estimated to be present in 1998. Effects of the 1999–2003 remediation on groundwater plumes were evaluated by the USGS using several methods including measurements of oil thicknesses in wells; field water-quality in groundwater; and vapor concentrations of methane, carbon dioxide, nitrogen, and oxygen in the unsaturated zone.

The objective of this study was to test our hypothesis that the renewed remediation would not noticeably change the extent of the oil distribution at the site. This hypothesis resulted in part from an estimate of the remediation efficacy based on oil-saturation measurements made at the site (Herkelrath, 1999). A secondary objective was to test our hypothesis that crude-oil removal from the remediation wells would not change the observed trend in vapor concentrations in the unsaturated zone.

Background

On August 20, 1979, about 16 km northwest of Bemidji, Minn., an 86-centimeter (cm) diameter crude-oil pipeline burst along a seam weld, spilling about 1.7 million L of crude oil onto glacial outwash deposits (fig. 1; Pfannkuch, 1979; Hult, 1984; Enbridge Energy, 2008). The oil sprayed over an area of about 6,500 square meters (m^2) and collected in topographic depressions where crude oil infiltrated through the unsaturated zone to the water table. Three subsurface oil bodies, herein termed the “north, middle, and south oil pools,” formed on and adjacent to the water table (fig. 1). The spilled oil was a light, low-sulfur crude with a kinematic viscosity ranging from 1.0 to 2.5×10^{-5} square meters per second (m^2/s) and a specific gravity ranging from 0.85 to 0.87 (Eganhouse and others, 1993; Landon, 1993; Lundy, 2015). In the local aquifer, groundwater at 20 degrees Celsius (°C) has a kinematic viscosity of 1.0×10^{-6} m^2/s. After repair of the ruptured pipeline, remediation efforts by the pipeline company resulted in an estimated 1.2 million L of the spilled oil being removed, leaving about 460,000 L of crude oil in the subsurface (Hult, 1984).

A long-term (20+ year), interdisciplinary research project was established by the USGS at the Bemidji site in 1983 in response to the research and regulatory community’s need for in situ field-scale studies of hydrocarbon fate and to complement ongoing experimental and modeling efforts (Delin and others, 1998). Since about 2008, the spill site has been referred to as the “National Crude Oil Spill Fate and Natural Attenuation Research site.” Crude oil trapped in the unsaturated zone and near the water table has provided a continuous source of hydrocarbon contamination since the spill occurred in 1979. Research at this site has been oriented toward characterizing and quantifying the physical, chemical, and biological processes controlling the fate of hydrocarbons in the subsurface. Results of this and other site research are summarized in Essaid and others (2011). Much of the research results in this report were presented in Delin and Herkelrath (2014); this report provides additional data and expands the interpretive details, most notably in relation to oil-thickness measurements, field water-quality data of dissolved oxygen, specific conductance, temperature, and pH in groundwater, and vapor concentrations.

In 1997, the Minnesota Pollution Control Agency required that the pipeline company remove any remaining crude to a sheen in all wells at the Bemidji site. The crude-oil-recovery system (figs. 1 and 2) consisted of five dual-pump remediation wells: two at the north oil pool (RW–1N, RW–2N), two at the middle oil pool (RW–1M, RW–2M), and one well connected to a drain tile at the south oil pool (RW–1S) (Natural Resources Engineering Company, 1998).

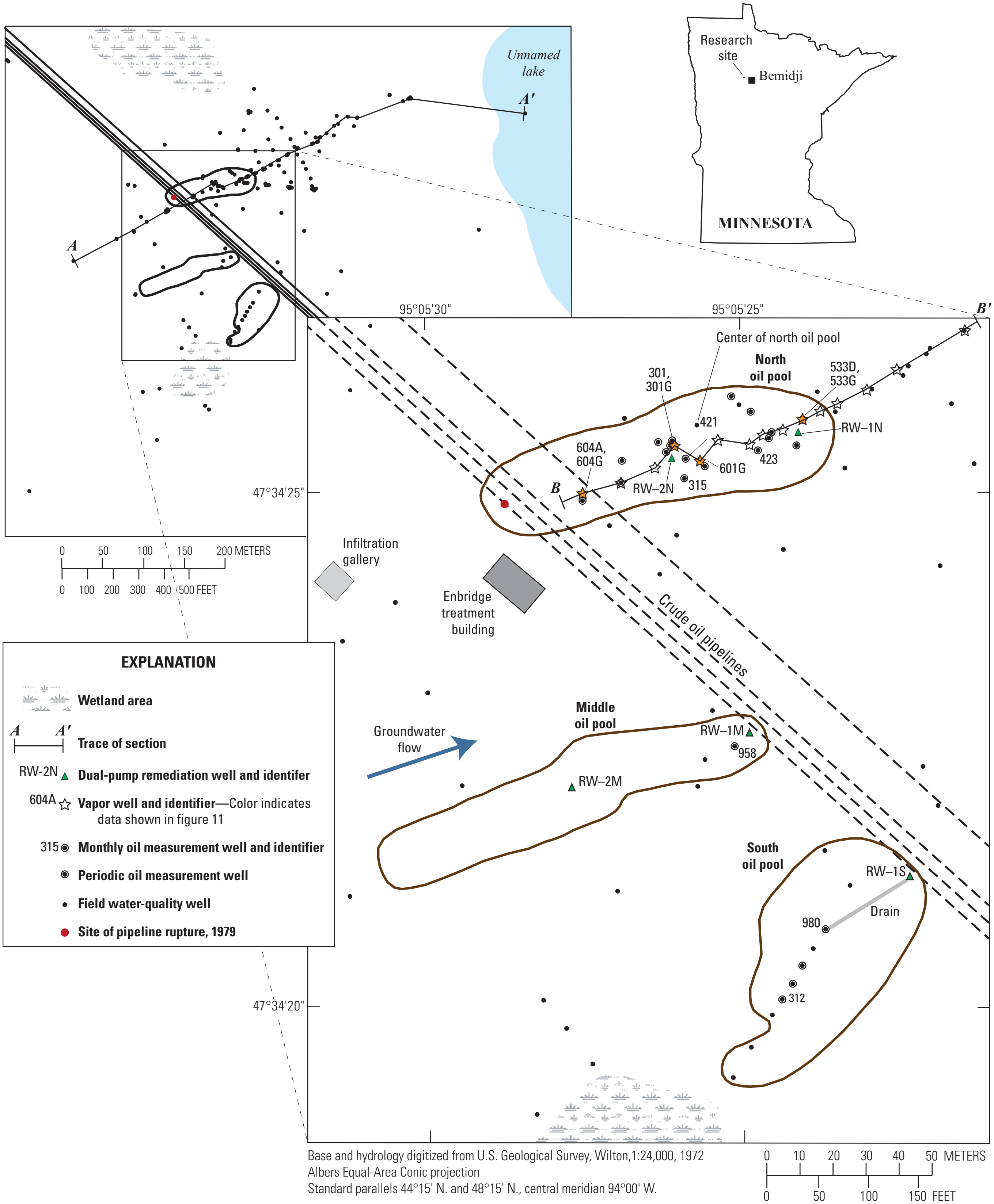


Figure 1. Observation wells at the National Crude Oil Spill Fate and Natural Attenuation Research site near Bemidji, Minnesota.

The purpose of the drain tile was to funnel the oil toward RW–1S. Each remediation well screen was 3.05 m long and extended from the water table downward. Pumping with a submersible groundwater pump placed near the bottom of the well created a depression in the water table, which caused crude oil to flow toward the well (fig. 2). The maximum total designed pumping rate for all five wells was 242 liters per minute (L/min) (Natural Resources Engineering Company, 1998, 1999). Crude oil was removed from each well using a pneumatic skimmer pump.

The water-oil mixture from each groundwater pump was discharged into a separator tank in a treatment building (fig. 1) where the oil was pumped to an adjacent storage tank and later removed from the site. Water from the separator tank had no additional treatment and was gravity fed into an infiltration gallery about 40 m west from the treatment building and upgradient from the north oil pool (fig. 1). The infiltration gallery had a surface area of about 37 m^2 and consisted of perforated drain laterals set in gravel beds 2–3 m below land surface. Most of the groundwater flowing from the infiltration gallery was intended to be intercepted and withdrawn by remediation wells RW–1N and RW–2N at the north oil pool (Natural Resources Engineering Company, 1998); however, as designed, the remediation system could not intercept all the water that infiltrated through the gallery.

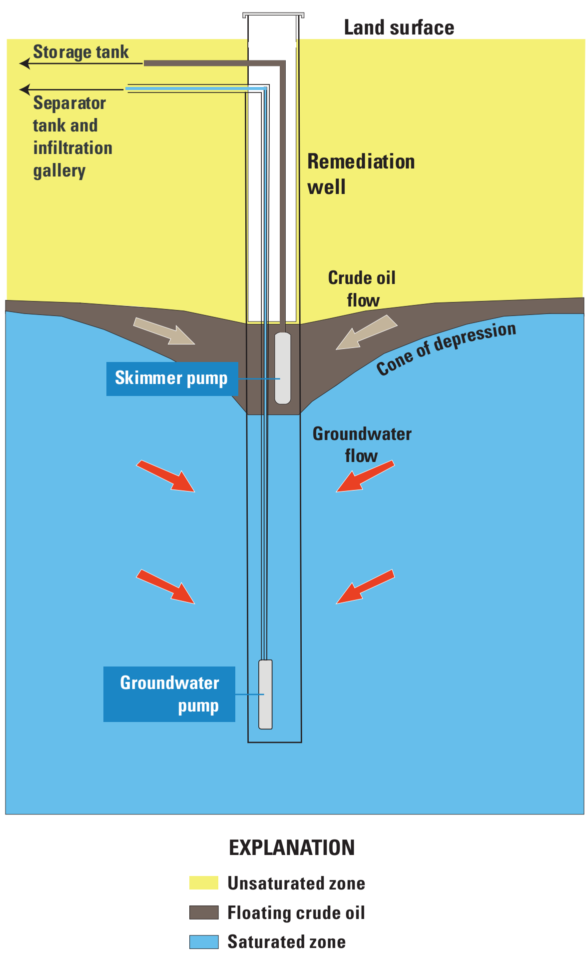


Figure 2. Conceptual diagram of the crude-oil-recovery system for the renewed remediation at the Bemidji, Minnesota, site, 1999–2003. The floating crude-oil zone contained a mixture of crude oil, air, and water in the pore space.

The site is underlain by a glacial aquifer that is 7–20 m thick, composed of moderately well sorted to poorly sorted sand and gravel with thin interbeds of silt (Franzi, 1988). A regionally extensive till layer underlies the surficial aquifer at depths of 23–28 m. Depth to the water table ranges from 0 m (near the wetland at the south oil pool, fig. 1) to 9 m (at the downgradient end of the floating oil at the north oil pool, fig. 1). Typical recharge rates at the site ranged from 0.1 to 0.3 meter per year (m/yr; Delin and Herkelrath, 1999, 2005). The greatest recharge rates occur beneath topographic lows, primarily as a result of accumulation of surface runoff.

Purpose and Scope

The purpose of this report is to present results of field data collection from 1994 to 2010, spanning a period of time extending from several years before (1994–98) to several years after (2004–10) the 1999–2003 remediation period. The field data that were collected included groundwater levels; oil thickness; water-quality properties including dissolved oxygen, specific conductance, temperature, and pH; and unsaturated-zone soil vapors including methane, carbon dioxide, oxygen, and nitrogen. This report is an expansion of the results presented by Delin and Herkelrath (2014), particularly the description of the field water-quality measurements in groundwater, unsaturated-zone vapor concentrations, and description of the relation between measured oil thickness and estimated water-table elevation.

Methods

This section describes the methods used for estimating initial and recoverable oil, measuring oil thickness, collecting and analyzing water-quality samples, and measuring unsaturated-zone vapor concentrations used in this study.

Estimating Initial and Recoverable Oil at the Bemidji Site

The USGS estimate of the volume of oil in the subsurface before the remediation was based on extraction of oil from cores collected from the north and south oil pools in 1998. This part of our research was described in detail by Herkelrath (1999), and an overview is provided in this report. Using methods described in Hess and others (1992) and Murphy and Herkelrath (1996), 17 cores were collected with a freeze shoe apparatus at the north and south oil pools and analyzed to measure the vertical distribution of oil, air, and water saturation at the north and south oil pools. Cores were not collected for this study at the middle oil pool. To capture the primary zones of oil saturation, the cores extended from about 30 cm above the capillary fringe in the unsaturated zone to about 30 cm below the water table in the saturated zone. The capillary fringe is a zone in which the water and oil saturation rapidly declined above the water table. It was assumed that oil that is more than 1 m above the water table would not be affected by the remediation (Herkelrath, 1999). This cutoff height above the water table was selected to roughly correspond to the top of the capillary fringe. The total volume of oil per unit area in each core (*Lo*) was estimated. *Lo* has dimensions of length and is equivalent to the length that the oil phase would occupy if the oil were present in a core liner without any sediment. A matrix of estimated values of *Lo* was generated on a uniform grid by interpolating between values of *Lo* measured at the boreholes. Contour maps of the interpolated total volume of oil per unit area at the north oil pool and south oil pool were generated by linear interpolation.

To obtain a first-order estimate of the amount of oil that could be recovered by the remediation, the concept of residual oil saturation (S_{or}) was adopted (Dullien, 1992). This concept is commonly used in petroleum engineering. Wherever the oil saturation was initially greater than a residual value of S_{or}, oil was assumed to be removed until the oil saturation was reduced to S_{or}; thus, it was assumed that the maximum oil saturation after remediation would be S_{or}. Wherever the initial oil saturation was less than S_{or}, it was assumed that the oil would be immobile and that the oil saturation would not change during the remediation.

S_{or} is difficult to estimate and has been determined to depend on many factors that vary widely from site to site; for example, Abdul (1992) reported that S_{or} ranged from 0.08 to 0.32 (8 to 32 percent of the pore space) in small funnels of sand and can be greater in a heterogeneous field environment. At the Bemidji site, one indicator of S_{or} is the level of oil saturation detected in the unsaturated zone beneath the location where oil infiltration occurred. After 19 years of drainage, the oily sediments detected in the unsaturated zone near the center of the north oil pool had drained to an oil saturation of 0.25±0.05. To cover the probable range indicated by these data, oil recovery was calculated assuming S_{or}=0.2 and 0.3.

The recoverable oil volume (V_{rec}) detected in each 75-mm-long core section was used to estimate total oil recovery as follows:

$$V_{rec}=V\phi\,(S_o-S_{or})\ (\text{for } S_o>S_{or}), \tag{1}$$

where

- V is the volume of the core section,
- ϕ is the porosity of the core section,
- S_o is the oil saturation in the core section, and
- S_{or} is the assumed residual oil saturation.

V_{rec} was assumed to be zero if S_o is less than S_{or}, as described in detail by Herkelrath (1999).

Individual V_{rec} values were summed to obtain an estimate of the recoverable oil volume per unit cross section at each borehole location (L_{rec}). A contour map of interpolated L_{rec} values at the north oil pool was developed using S_{or}=0.3. By integrating over the interpolated L_{rec} matrices, it was estimated that 23,000 (S_{or}=0.3) to 37,000 (S_{or}=0.2) L of oil could be recovered from the north oil pool. Similar calculations using the south oil pool data indicate that 6,000–16,000 L of oil could be recovered there. An accurate estimate of recoverable oil volume using the previously mentioned methodology could not be made for the middle oil pool because cores were not collected from that area.

Measuring Oil Thickness

To evaluate effects of the crude-oil-recovery system, crude-oil thickness was measured in selected wells from 1994 through 2008. Results from previous studies indicate that substantially different volumes of LNAPL may produce the same thickness in an observation well; however, under vertical equilibrium conditions, there should be no exaggeration of LNAPL thickness in a monitoring well compared to the porous media (Abdul and others, 1989; Farr and others, 1990; Lenhard and Parker, 1990; Huntley and others, 1994b). Results from studies at sites where the water-table elevation was fluctuating indicate that oil thickness in observation wells tends to decrease when the water table rises and increase when the water table falls (Hampton and Miller, 1988; Lundy and Gogel, 1988; Kemblowski and Chiang, 1990; Mercer and Cohen, 1990; Marinelli and Durnford, 1996). A rising water table forces oil to flow out of a well bore and into the formation, thereby reducing oil thickness in the well. Conversely, a declining water table allows oil to flow back into the well bore, causing an increase in oil thickness in the well. This flow of oil back into the well depresses the water level, resulting in measured oil thicknesses that may exceed corresponding oil thicknesses in the formation by a factor between 2 and 10 (Mercer and Cohen, 1990).

Oil thicknesses and water levels were measured using an ORS oil-water interface meter in 7 wells monthly and in 16 additional wells once per year (fig. 1; appendix 1). Water- and oil-level data generated during this study are available as a USGS data release (Trost and others, 2020). The water-level data are also available through the USGS National Water Information System (NWIS) database (U.S. Geological Survey, 2020) and can be retrieved using the site identifiers listed in appendix 1. The wells were constructed of 5-cm-diameter polyvinyl chloride (PVC) or galvanized steel, with 0.15–1.5-m-long PVC or stainless-steel screens. The water-table elevation in wells containing crude oil was calculated as the product of oil thickness and a crude-oil specific gravity of 0.855 (Lundy, 2015) plus the elevation of the measured water-oil interface.

Collecting and Analyzing Water-Quality Samples

A network of about 100 wells (fig. 1) was sampled each summer from 1998 through 2010 for analyses of selected field water-quality properties that were indicators of effects of the remediation. Specific conductance, pH, dissolved oxygen, and temperature were determined in the field using either a YSI multimeter (model 682–C–M) or a Hydrolab DataSonde 3 or Surveyor 4. Dissolved oxygen and ferrous iron concentrations were measured in the field using CHEMets® Kits (CHEMetrics Inc., Calverton, Virginia). Wells were purged and samples collected in a manner to minimize aeration of the water in the well or the sample during pumping, using positive displacement pumps and gas-impermeable high-density plastic tubing. The measurements were collected in triplicate, and the lowest value measured was reported. These water-quality data can be retrieved from the USGS NWIS database (U.S. Geological Survey, 2020) for the sites listed in appendix 1.

Research completed at this site by Bennett and others (1993) indicates that the combination of dissolved oxygen and specific conductance was a good indicator of biodegradation processes (also National Research Council, 2000). In this study, it was assumed that a dissolved oxygen concentration in groundwater of less than 1.0 milligram per liter (mg/L) was representative of anoxic conditions in the saturated zone because of microbial biodegradation associated with the crude-oil contamination. By comparison, background dissolved oxygen concentrations typically range from 6 to 7 mg/L in uncontaminated areas at the site. Similarly, background specific conductance concentrations in groundwater at the site typically range from 300 to 500 microsiemens per centimeter (µS/cm), which increases to between 500 and 900 µS/cm in areas affected by the crude-oil contamination.

Funds were insufficient to collect samples for benzene, toluene, ethylbenzene, and xylenes (BTEX) analysis during the remediation; however, in July 2007, 3.5 years after the remediation had ended, samples were collected from selected wells at the site for BTEX analysis by a separate research study (Amos and others, 2012). Methods used in collecting and analyzing the BTEX samples are included in Amos and others (2012).

Measuring Unsaturated-Zone Vapor

Vapor samples were collected from the unsaturated zone in the summer during 1997, 1999, and each year from 2001 through 2010. Samples were collected from 15 unsaturated-zone vapor wells, each with multiple vertical sampling ports. The vapor wells are about 10 m apart horizontally at the north oil pool (figs. 1 and 3). Each vapor well consisted of permanently installed vapor probes generally spaced at 50–100-cm depth intervals in the unsaturated zone, from about 1 m below land surface to 1 m above the water table (fig. 3 and appendix 1). Each probe was constructed of 0.16–0.64-cm outside diameter stainless-steel tubing with 1–2-cm-long screened intervals at the bottom. The probes were placed in 10-cm-diameter augered holes, which were then backfilled with native sand and bentonite. Vapor samples were collected in gas-tight glass syringes using a peristaltic pump and analyzed onsite using an SRI® 8610C gas chromatograph (GC). The GC was configured using a 1.0-milliliter fixed-loop injection and an internal air compressor. Fixed gas (oxygen, carbon dioxide, methane, and nitrogen) analyses were determined with a thermal conductivity detector and an SRI® CTR–1 double packed column. Calibrations were carried out using gas standards containing mixtures of oxygen, carbon dioxide, methane, and nitrogen. Preliminary vapor transport data collected at the site in 1985 were summarized by Hult and Grabbe (1988). Results from the 1997 and 1999 data collections were summarized by Chaplin and others (2002). The vapor data used in this report are published in the USGS NWIS database (U.S. Geological Survey, 2020) and can be retrieved using the station identifiers in appendix 1. Well construction and location details are also published in Trost and others (2018).

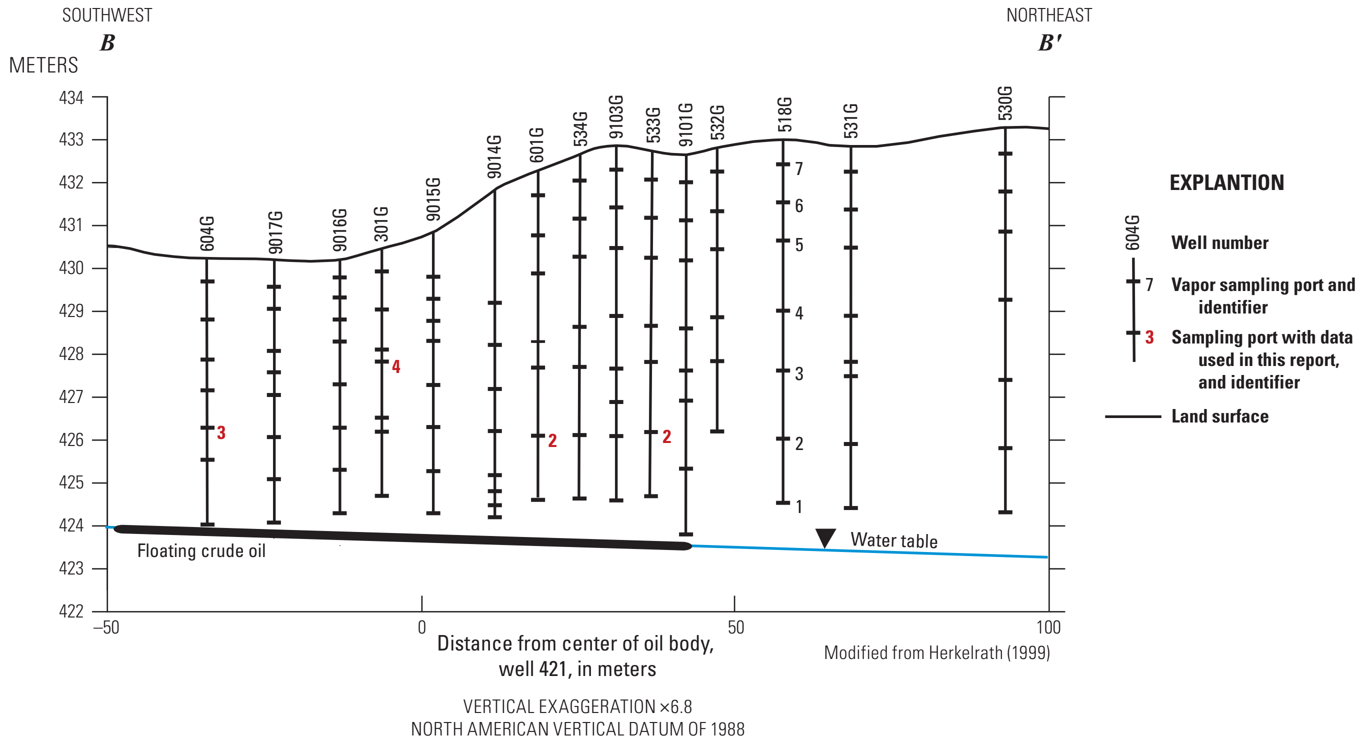


Figure 3. Vapor well sampling port locations at the Bemidji, Minnesota, north oil pool.

Aquifer Hydraulic Properties

Previous estimates of hydraulic conductivity at the north oil pool were about 8-m/d (Dillard and others, 1997; Essaid and others, 2003). The mean aquifer porosity is 0.38 (Dillard and others, 1997). Based on the previously mentioned estimates of porosity and hydraulic conductivity and an average hydraulic gradient of 0.0035 meter per meter (Essaid and others, 2003, 2011), estimated pore-water velocity at the site is about 0.7 m/d.

Oil Removed by 1999–2003 Remediation

The following sections of the report describe the oil removed during remediation completed in 1999–2003 at the Bemidji site. Included in these sections are estimates of initial oil in the subsurface before the remediation began, recoverable oil, and reported oil recovered at the Bemidji site.

Estimate of Initial Oil at the Bemidji Site, Before Renewed Remediation

By integrating over the interpolated matrices of oil in the unsaturated and saturated zones (fig. 4), the total amount of oil at the north oil pool before the start of the remediation was estimated at 88,000 L near the water table and 59,000 L in the unsaturated zone (table 1). At the south oil pool, the water table is only about 2 m below the surface, and almost all the oil is near the water table (table 1); therefore, all the oil at the south oil pool was assumed to be affected by the remediation. It was estimated that the total amount of oil at the north and south oil pools before the start of the remediation was 147,000 L and 94,000 L, respectively (table 1), for a total of 241,000 L for both pools. Cores were not collected for this study at the middle oil pool, and thus, an accurate estimate of oil volume in the middle oil pool could not be made.

The Natural Resources Engineering Company (NREC; 1998) estimated oil volumes at the site before the renewed (1999–2003) remediation as the product of measured oil thickness in wells, times the areal extent of each oil pool using push-probe coring, times a published aquifer porosity of 0.25 (Miller, 1984). Cores were collected from 56 push-probe holes, and measurements of oil thicknesses were made in 16 wells on May 15, 1998. The NREC assumed that the thickness of oil in the observation wells equaled the thickness of oil in the aquifer matrix.

The approximate volume of oil in the middle oil pool was estimated in this study by evaluating the relations between the estimates from the NREC (1998) for the north and south oil pools with the corresponding USGS estimates based on cores and applying this relation to the middle oil pool. USGS estimates of oil at the north and south oil pools (147,000 and 94,000 L, respectively; table 1) represent 41 percent and 78 percent, respectively, of the NREC estimates for the north and south oil pools. When these ratios are applied to the

Table 1. Estimates of initial and recoverable volumes of crude oil at the Bemidji, Minnesota, north and south oil pools (modified from Herkelrath, 1999).

[Because the water table is only about 2 meters below the surface at the south oil pool and almost all the oil is near the water table, all the oil at the south oil pool was assumed to be affected by the remediation. USGS, U.S. Geological Survey; NREC, data are from Natural Resources Engineering Company (1998); north, south, middle, oil pool locations; NA, not available]

Type	Assumed residual oil saturation, in thousands of liters						
	USGS				NREC		
	North		South		North	South	Middle
	0.3	0.2	0.3	0.2	0.25	0.25	0.25
Initial oil, unsaturated zone	59	59	0	0	NA	NA	NA
Initial oil, near water table	88	88	94	94	NA	NA	NA
Total initial volume	147	147	94	94	358	121	97
Recoverable oil	23	37	6	16	NA	NA	NA
Oil remaining in subsurface after remediation	124	110	88	78	NA	NA	NA
Recoverable oil volume/total initial oil volume (in percent)	16	25	7	17	NA	NA	NA

NREC estimate for the middle oil pool of 97,000 L, the USGS estimate of oil volume for the middle oil pool is between about 40,000 and 76,000 L. When these estimates are added to the values in table 1 for the north and south oil pools, the total USGS estimated volume of oil for all three oil pools before the remediation is between 281,000 and 317,000 L.

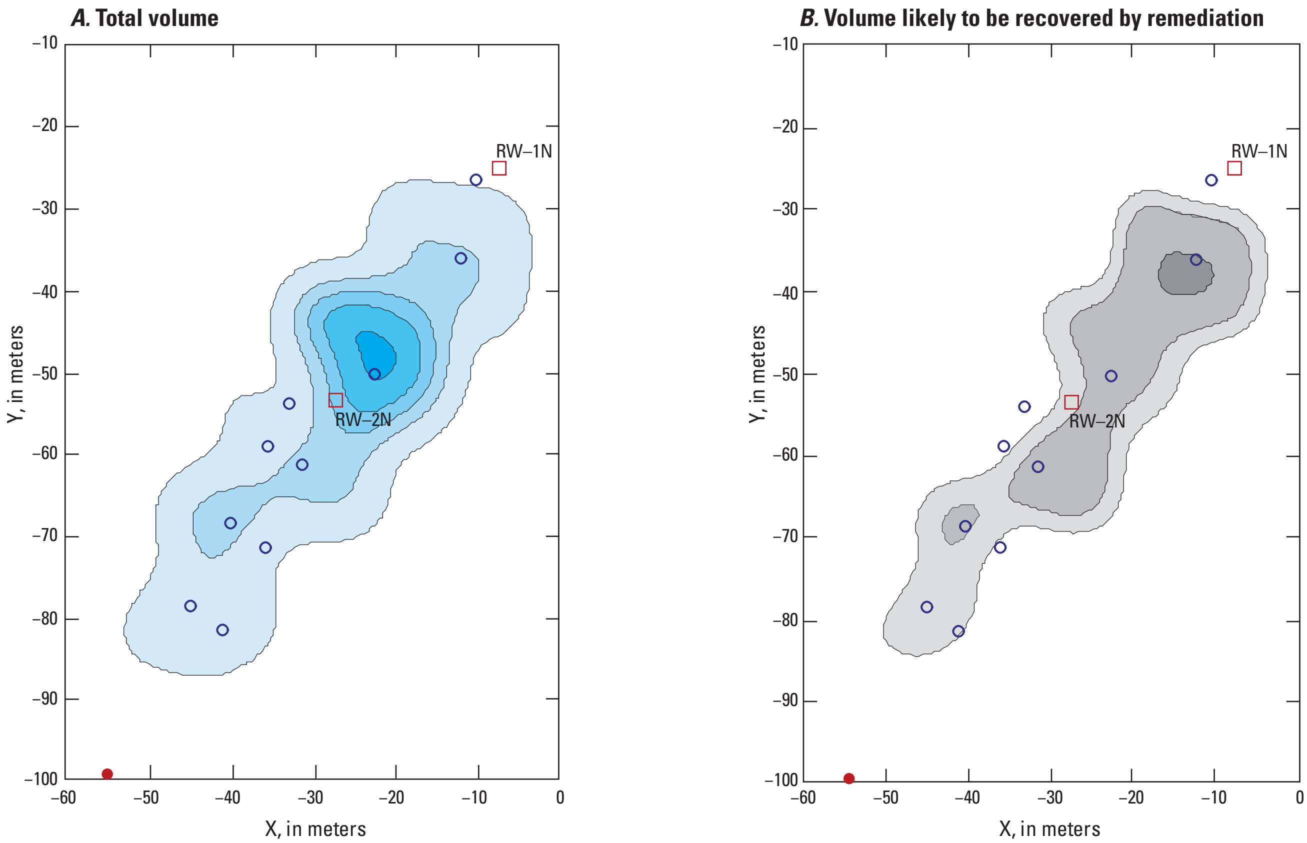
Estimate of Recoverable Oil at the Bemidji Site

A substantial fraction of the oil at the north oil pool is above the water table, in the 6-m-thick unsaturated zone (Herkelrath, 1999). Some of the oil in the unsaturated zone is beneath areas where the oil originally infiltrated into the ground and represents a residual saturation of oil that is trapped or flows slowly downward. This oil was hypothesized to be immobile during the remediation.

Results of the residual oil-saturation model indicated that about 110,000–124,000 L of oil would remain at the north oil pool (fig. 3; table 1) and about 78,000–88,000 L would remain at the south oil pool after the renewed oil-recovery remediation (table 1). Thus, the total predicted volume of recoverable oil from the north and south oil pools combined ranged from about 29,000 to 53,000 L based on residual oil saturations of 0.3 and 0.2, respectively. The predicted low oil recoveries (16–25 percent at the north oil pool; 7–17 percent at the south oil pool) are in good agreement with other case studies (for example, Abdul, 1992) and from experience within the oil industry (American Petroleum Institute, 2003). These calculations illustrate how difficult it is to remove separate-phase oil from sediments using standard oil-removal technology. If we assume that the recoverable oil from the middle oil pool was in a similar range to that estimated at the north and south oil pools (in other words, 7–25 percent), recoverable oil from the middle oil pool was likely between about 2,800 and 19,000 L. Thus, the total predicted volume of recoverable oil from all three oil pools ranged from about 31,800 to 72,000 L (or about 10–26 percent of the estimated volume of 281,000–317,000 L of oil at the north, middle, and south oil pools before the remediation).

Reported Oil Recovery

The reported oil recovery values are shown in table 2. The initial oil estimates for the north and south oil pools by the NREC are 243 and 129 percent larger, respectively, than the values estimated in this study (table 1). Oil-recovery rates were greatest during the first year (1999) of the remediation (table 2), with combined rates from all wells as high as about 300 liters per day (fig. 5) (Natural Resources Engineering Company, 2008). This trend in crude-oil recovery is similar to those reported elsewhere in the literature (for example, Abdul, 1992). The observed fluctuations in oil-recovery rates during the remediation, particularly during 1999, were due to problems with the wells and pumps that necessitated temporary shutdown of the oil-recovery system for repair (Natural Resources Engineering Company, 1999). Oil-recovery rates declined in 2000–3, as reflected in the daily oil-recovery and cumulative oil-recovery graphs (fig. 5). Total reported crude-oil recovery is shown in table 2 (Natural Resources Engineering Company, 2008); thus, the renewed remediation from 1999 to 2003 resulted in removal of a total of about 115,000 L of crude oil from the site (table 2; Natural Resources Engineering Company, 2008). This represents 36–41 percent of the USGS total of 281,000–317,000 L estimated to be present at the north, middle, and south oil pools in 1998. The 115,000 L of oil removed represents only 19 percent of the NREC (1998) estimate of 575,500 L of oil in the subsurface before the start of the remediation.



EXPLANATION

[Numbers correspond to estimated crude-oil volume for a residual oil saturation (S_{or}) value of 0.3, in centimeters. The total volume of oil per unit cross-sectional area (*Lo*) in each borehole was estimated. *Lo* has dimensions of length and is equivalent to the length that the oil phase would occupy if the oil were present in a core liner without any sediment; axis labels use local coordinate system]

Total volume of oil per unit cross section, in centimeters

- 2 to 10
- >10 to 18
- >18 to 26
- >26 to 34
- >34

RW–1N **Oil recovery well and identifier**

Borehole used in this analysis

Site of pipeline rupture, 1979

Volume of oil per unit cross section that is likely to be recovered by remediation, in centimeters

- 1 to 2
- >2 to 4
- >4

Figure 4. Estimated total volume of crude oil per unit cross section at the north oil pool. *A*, oil volume per unit cross sectional area in centimeters in 1998, before the start of the remediation; *B*, oil volume per unit cross sectional area in centimeters that was likely recoverable by the remediation given free oil flow and time. Modified from Herkelrath (1999).

Table 2. Total crude-oil recovery, in liters, reported by the Natural Resources Engineering Company (2008).

Year	Reported recovery
1999	47,300
2000	21,100
2001	19,900
2002	11,000
2003	13,700
Total	115,000

The most likely causes for the differences between USGS's estimated oil-recovery volume (of 31,800–72,000 L) for this study and the reported oil-recovery volume (of 115,000 L, Natural Resources Engineering Company, 2008) are as follows. (1) The USGS estimate of oil volume in place before remediation may be too low. The oil pools may have been more extensive than indicated by our relatively limited coring campaign. (2) The assumed minimum residual oil saturation of 0.2–0.3 predicted to remain after the remediation may be too high. Unfortunately, we did not have the resources to recore the site after the remediation to measure the remaining oil-saturation distribution. (3) The reported oil-recovery

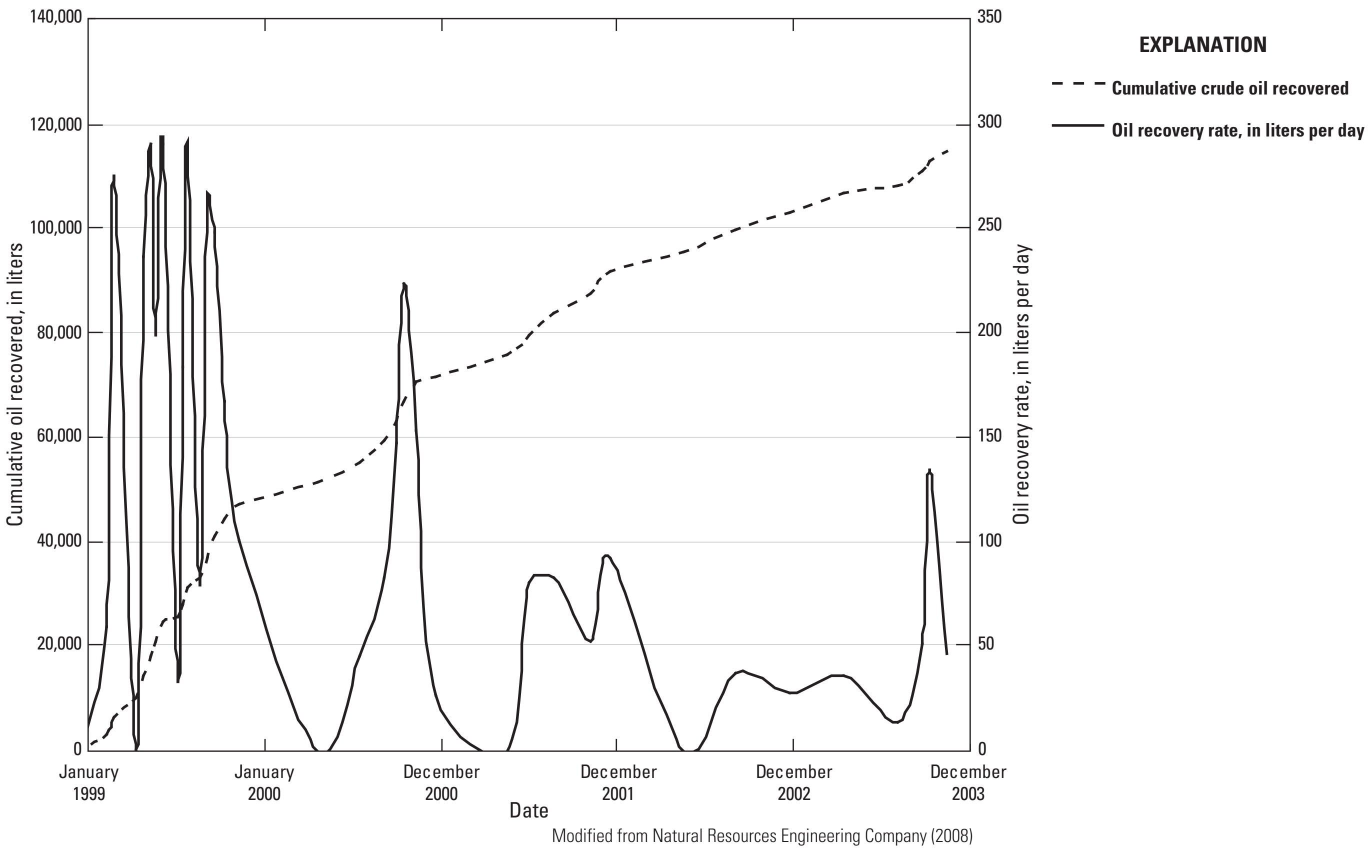


Figure 5. Oil-recovery rates and cumulative oil recovered at the Bemidji, Minnesota, site, 1999–2003.

volume may be too high because of the difficulty of separating oil from water in the field and measuring the recovered oil volume; for example, some volume of water may have been included in the reported recovered oil volume.

Effects of the Crude-Oil Recovery Remediation System on Groundwater Plumes and Unsaturated-Zone Vapor Concentrations

The following sections of the report describe the effects of the 1999–2003 remediation on groundwater plumes and unsaturated-zone vapor concentrations at the Bemidji site. Included in these sections are descriptions of the oil thicknesses and water levels in wells, the remediation plume in groundwater, and the unsaturated-zone vapor concentrations.

Oil Thickness

Although the oil-recovery system successfully removed oil from a relatively short radius around each remediation well, the remediation did not appreciably affect overall oil thicknesses measured in wells at the north and south oil pools. Average oil thicknesses in 18 wells at the north oil pool were about 0.7 m in 1998 before the remediation, varied between about 0.4 and 0.8 m from 1999 to 2003 during the remediation, and varied between about 0.4 and 0.7 m from 2004 to 2008 after the remediation ended. Average oil thicknesses in wells at the south oil pool were about 0.5 m in 1998 before the remediation, varied between about 0.2 and 0.4 m from 1999 to 2003 during the remediation, and remained constant at about 0.3 m from 2004 to 2008 after the remediation ended. The lack of change in thickness at the north and south oil pools, as well as seasonal fluctuations in average oil thickness, do not seem to be linked to the remediation but are more likely the result of natural fluctuations of recharge and discharge from the aquifer. Following are results from three observation wells close to the remediation wells as examples of the maximum effects of the remediation.

To evaluate effects of the remediation on oil thicknesses, wells 301A, 315, and 980 were selected for detailed analysis because of their proximity to the remediation wells (fig. 1). In well 315 at the north oil pool, 7.5 m south of remediation well RW–2N (fig. 1), oil thicknesses fluctuated seasonally with only a slight decrease in thickness during the remediation (fig. 6). Based on the linear regression line through the data, this decrease was consistent with the downward trend in oil thickness from 3 years before to 5 years after the remediation ended (1996–2008). The seasonal fluctuations in oil thickness are not linked to the remediation but are the result of natural fluctuations of recharge and discharge from the aquifer.

Of all the wells monitored during the 1999–2003 remediation, the greatest change in oil thickness was observed in well 980 at the south oil pool, 3 m from the drain attached to remediation well RW–1S (fig. 1). Oil thicknesses in this well decreased to near zero during the remediation but rebounded to preremediation levels within about 1 year after the remediation ended (fig. 7). Well 980 did not have the thickest oil at the site before the remediation; however, its thicknesses were generally less than 0.5 m compared to thicknesses as great as 1.0 m in wells such as 315 at the north oil pool.

At well 301A, about 5.0 m from remediation well RW–2N at the north oil pool (fig. 1), the average oil thicknesses for 1994–98 (before), for 1999–2003 (during), and for 2004–9 (after the remediation) were 0.600 m, 0.612 m, and 0.521 m, respectively, indicating a relatively small effect from the remediation. However, figure 8*A* demonstrates that the oil thicknesses in well 301A were substantially reduced by the remediation when accounting for water-level elevation. The approximate vertical distance between the before-regression line (black) and the after-regression line (green) is about 0.2–0.4 m. This indicates that at a given water level, the oil thicknesses were about 0.2–0.4 m less after the remediation compared to before the remediation. Oil viscosities in four wells at the north oil pool increased during the remediation by as much as 20 percent (Lundy, 2015). This increase in oil viscosity may have affected oil thicknesses in wells but an evaluation of this kind was beyond the scope of this study. Although the thicknesses were reduced, the after-remediation

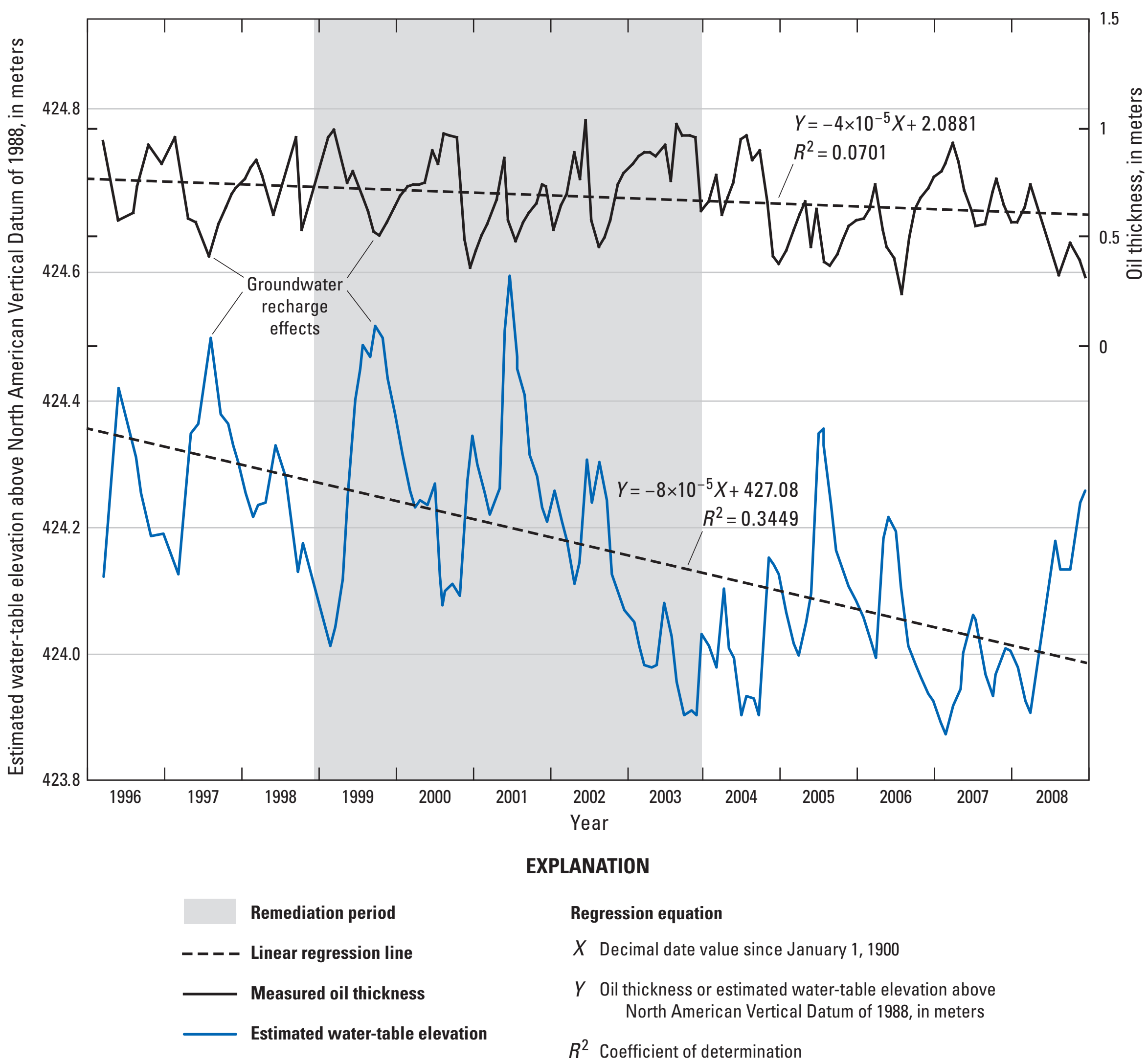


Figure 6. Oil thickness and estimated water-table elevation for well 315 at the north oil pool of the Bemidji, Minnesota, site, 1996–2008. Effects of groundwater recharge are apparent as rises in the water table coupled with declines in oil thickness, and vice versa.

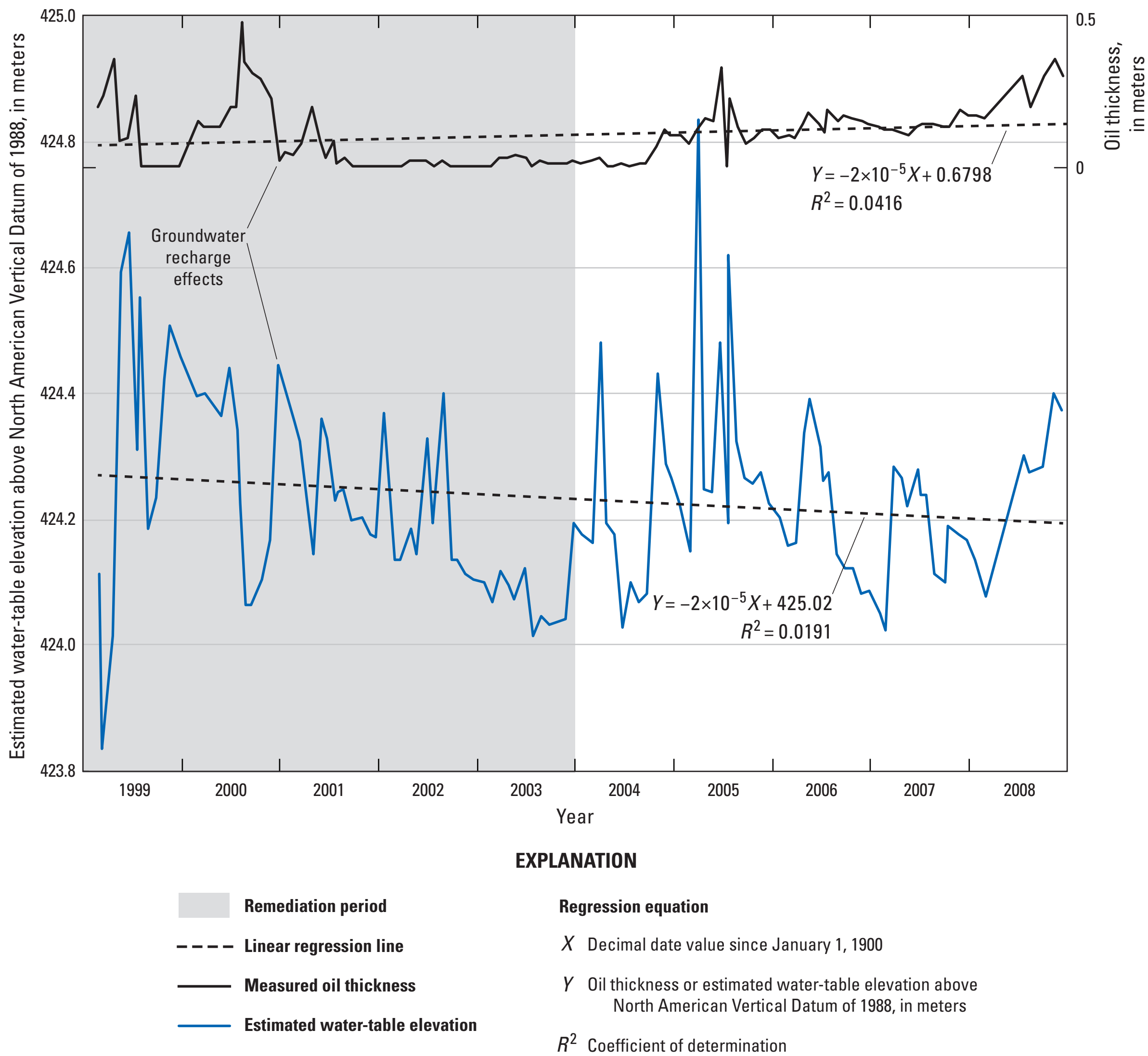


Figure 7. Oil thickness and estimated water-table elevation for well 980 at the south oil pool at the Bemidji, Minnesota, site, 1999–2008. Note that oil thickness was close to zero for about 3 years during the remediation.

data indicate that substantial amounts of oil remained in the subsurface and that the remediation did not achieve the sheen objective.

At well 315, located 7.5 m from remediation well RW–2N at the north oil pool (fig. 1), the average oil thicknesses for 1994–98 (before), for 1999–2003 (during), and for 2004–9 (after the remediation) were 0.740 m, 0.715 m, and 0.563 m, respectively. Similar to well 301A, the average oil thicknesses for well 315 indicate a relatively small effect of the remediation effort. The approximate vertical distance between the before-regression line (black) and the after-regression line (green) is about 0.4 m. This indicates that at a given water level, the oil thicknesses were about 0.4 m less after the remediation compared to before the remediation. Although the thicknesses were reduced, the after-regression data once again indicate that substantial amounts of oil remained in the subsurface and the remediation did not achieve the sheen objective.

At well 980, 3.0 m from the drain connected to remediation well RW–1S at the south oil pool (fig. 1), the average oil thicknesses for 1989–96 (before), for 1999–2003 (during), and for 2004–9 (after the remediation) were 0.780 m, 0.081 m, and 0.130 m, respectively. Fewer oil-thickness measurements were available for well 980 before the start of the remediation and the period during which the measurements were made was slightly earlier compared to the measurements for wells 301A and 315 (fig. 8). Comparison of the oil-thickness measurements at wells 980, 301A, and 315 for the same slightly earlier period, however, indicate that the data at well 980 are nevertheless representative of the preremediation conditions for 1994–98. The data in figure 8*C* indicate a relatively large

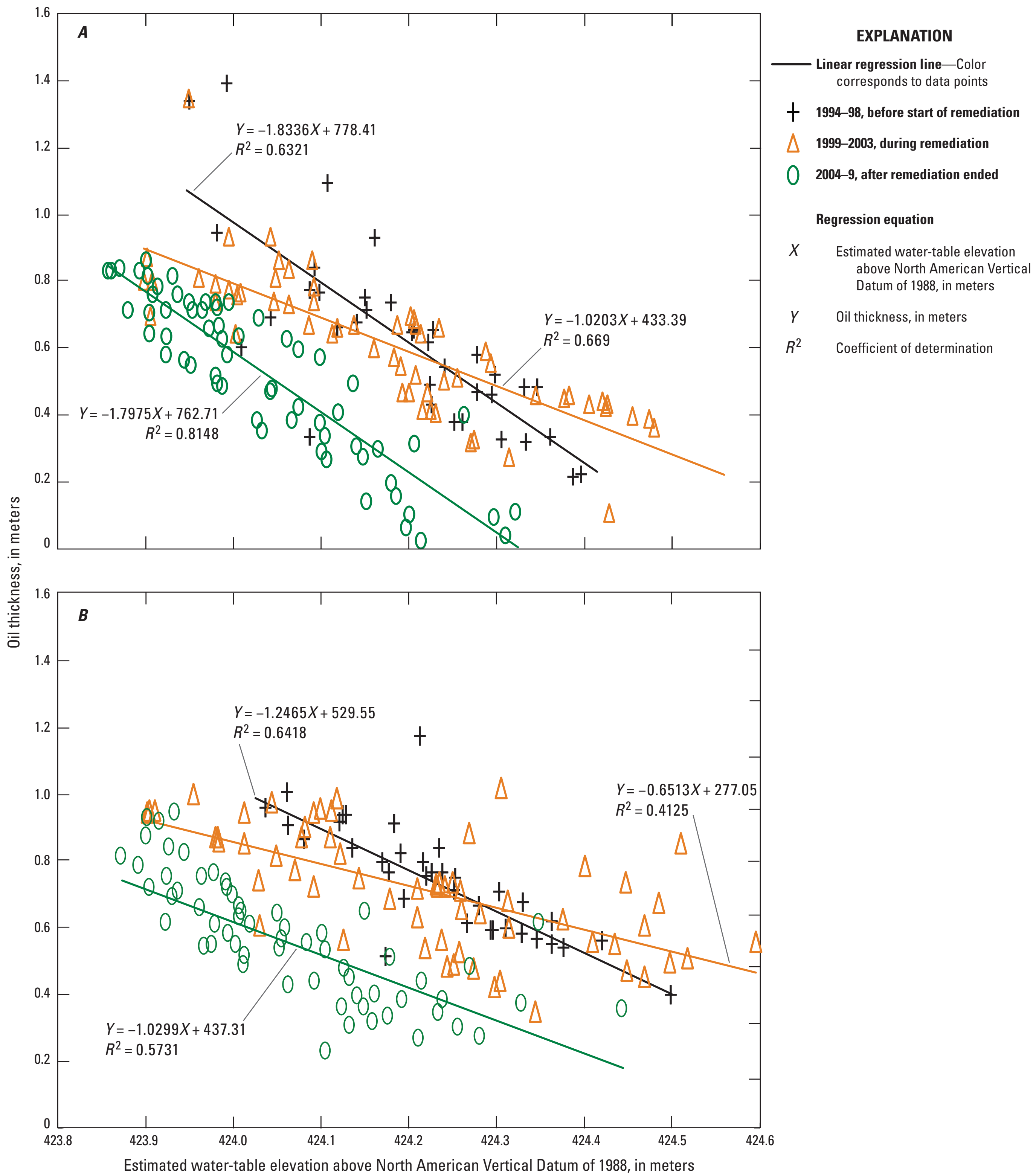


Figure 8. Relation between estimated water-table elevation and oil thickness in wells at the Bemidji, Minnesota, north oil pool. *A*, well 301A; *B*, well 315; *C*, well 980. The slope of the regression line through the data collected during the remediation is shallower than the regression lines before and after the remediation.

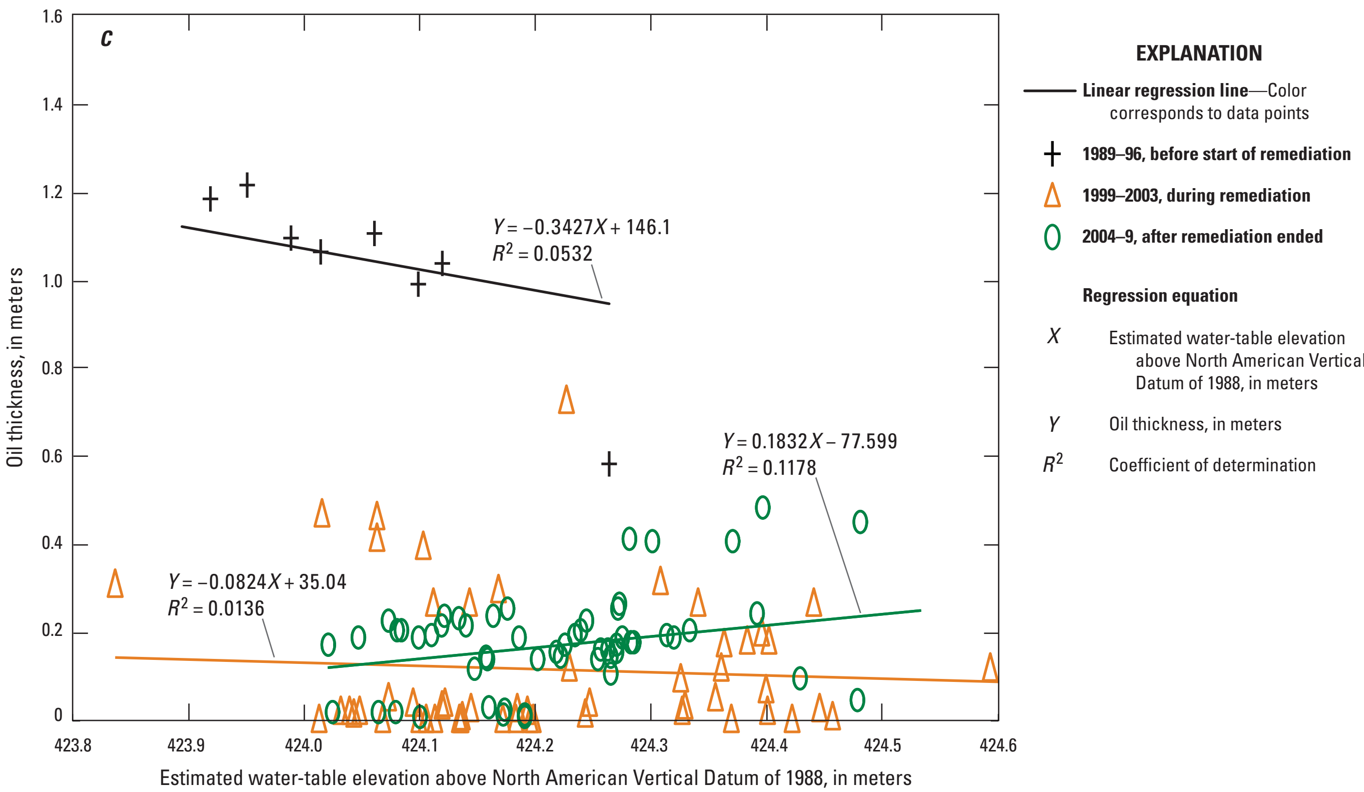


Figure 8. Relation between estimated water-table elevation and oil thickness in wells at the Bemidji, Minnesota, north oil pool. *A*, well 301A; *B*, well 315; *C*, well 980. The slope of the regression line through the data collected during the remediation is shallower than the regression lines before and after the remediation.—Continued

effect of the remediation effort at well 980. The approximate vertical distance between the before-regression line (black) and the after-regression line (green) is about 0.7–0.9 m. This indicates that at a given water level, the oil thicknesses were about 0.7–0.9 m less after the remediation compared to before the remediation. The comparatively large effect of the remediation in reducing oil thicknesses at well 980 largely is due to the proximity of the well to the drain (3.0 m) at the south oil pool (fig. 1). Although oil thicknesses were reduced substantially at well 980, the after-remediation data indicate that 0.1–0.4 m of oil nevertheless remained in the subsurface and the remediation did not achieve the sheen objective. Note that the slope of the regression line for the measurements made after the remediation ended is positive (fig. 8*C*) instead of negative, as is the case for wells 301A and 315 (figs. 8*A* and *B*). This positive slope results because the well is only 3.0 m from remediation well RW–1S and oil thicknesses at well 980 began increasing immediately after the remediation ended. In other words, wells that were farther away from a remediation well had a shallower gradient and reflected a smaller effect of the remediation.

The previously mentioned results are consistent with the study hypothesis, that the remediation would not achieve the objective of removing oil to a sheen in all wells. It is unclear if the oil-recovery system was able to remove oil from the groundwater system to a sheen in any area, even within 2–5 m of the remediation wells, as required by the State regulatory agency. In general, changes in average oil thickness at the north and south oil pools were relatively minor from before to after the remediation. These results illustrate that using oil-thickness data to evaluate the effects of remediation of a crude-oil contamination site does not produce a useful or meaningful measure.

The results from this study are consistent with data from previous studies. A negative correlation typically exists between water-table elevation and LNAPL thickness in monitoring wells at most spill sites (Kemblowski and Chiang, 1990; Charbeneau and others, 1999). The most likely mechanisms for this relation are as follows: (1) increased oil entrapment and decreased mobile oil in high water-table conditions causes a reduction in oil thickness compared to low water-table conditions, and (2) under nonequilibrium conditions, monitoring wells act as conduits for preferential flow of liquids (Kemblowski and Chiang, 1990; Marinelli and Durnford, 1996). This second point, however, is only a factor in low permeability formations and thus does not apply to the Bemidji site, which has a relatively high permeability as described previously. Hysteresis in soil fluid retention curves also affects the oil thickness in wells. At the same water-table elevation, oil thicknesses tend to be greater during a period of water-table decline than during a period of water-table rise (Marinelli and Durnford, 1996).

A negative correlation between the estimated water-table elevation and measured oil thickness is evident in most of the data collected from wells 301A, 315, and 980 (fig. 8). The slopes of all the data are negative except for data collected after the remediation at well 980 (fig. 8*C*). As described earlier, this positive slope results at well 980 because this well is only 3.0 m from remediation well RW–1S and oil thicknesses began increasing immediately after the remediation ended. The remediation depleted oil to an increasingly greater extent with closer proximity to each of the remediation wells. After the remediation ended, oil continued to flow toward each remediation well because the oil surface still sloped in that direction and because of a nonequilibrium hydraulic condition. This redistribution of the oil after the remediation ended is only evident in the data from well 980, however, as reflected in the positive slope of the postremediation data in figure 8*C*, because of it being closer to a remediation well compared to wells 301A and 315.

As illustrated in the results from wells 301A, 315, and 980 (fig. 8), the relation between the measured oil thickness and estimated water-table elevation is inconsistent. This inconsistency was observed in the data across the site. The negative correlation between these two datasets was not prevalent at all wells (including wells not shown in this report); however, for virtually all wells where more than about 40 oil-thickness measurements were made before, during, and after the remediation, a negative correlation was observed. Also, most of the wells where oil-thickness measurements were made were more than 10 m from a remediation well and consequently indicated lesser effects from the remediation. Because of the hysteretic relation between oil thickness and water-level fluctuations, having enough measurements is critical to demonstrate the negative relation between oil thickness and estimated water level. Additional research is needed to better clarify the importance and relevance of correlating these data as a tool in evaluating crude-oil contamination and some initial ideas are discussed here.

Study results indicate that the previously mentioned analysis of plotting oil thickness versus estimated water level could prove beneficial at existing crude-oil spill sites such as refineries or storage facilities. For example, one procedure that could be used would be to monitor oil thickness and plot these data versus water-table elevation weekly to monthly for 1-year periods. Changes in slope or changes in offset in these plots may indicate a change to the amount of product in the system.

The most apparent change that could indicate product being added to a groundwater system is an increase in the vertical offset in the thickness to water-level relation. In all three examples (fig. 8), the after-remediation oil thicknesses were noticeably lower than the before-remediation oil thicknesses at the same water level. If enough data are collected over the course of several years, the data could be grouped (for example, by years) to look at year-to-year shifts in the offset. If oil had been added to the system, a vertical increase in the offset is expected to be apparent in the data. This would be the reverse of what was observed in this study, when the offset decreased after oil was removed (fig. 8). Evaluating the data this way is much more effective for detecting and evaluating changes to oil in the system compared to simply evaluating average oil thickness over time.

The slopes of the regression lines in figure 8 also change consistently and indicate a sensitivity of the oil-thickness/water-level relation to changes in gradients and stresses present in the system. The slope decreased during the remediation for all three wells. In addition, the after-remediation slope is rotated counterclockwise compared to the before-remediation slope for all three wells. For well 980 (fig. 8*C*), the slope is rotated so far counterclockwise that it became positive. This change in slope could be due to the redistribution of the oil after the remediation. Redistribution of oil also occurred at wells 301A and 315, but to a lesser degree, because they are farther from a remediation well. The rate at which oil is being added in the vicinity of a monitoring well seems to be related to how much the slope of the regression line is rotated compared to the previous condition.

Remediation Plume in Groundwater

The following subsections of the report describe the remediation plume at the Bemidji site during the remediation completed in 1999–2003. Included in these sections are descriptions of field water-quality properties of dissolved oxygen, specific conductance, temperature, and pH in groundwater in relation to the remediation plume; estimates of the remediation plume location; and measurements of benzene, toluene, ethylbenzene, and xylene (BTEX) in relation to the remediation plume.

Field Water-Quality Measurements and the Remediation Plume

Crude oil trapped in the unsaturated zone and near the water table has provided a continuous source of hydrocarbon contamination to groundwater at the site since 1979 (Essaid and others, 2011). Hydrocarbons have dissolved from the oil at varying rates, changing the source composition and forming a groundwater plume. The dissolved compounds have been transported in the saturated zone, forming a plume of hydrocarbons, associated degradation intermediates, and end products (herein termed the “natural attenuation plume”). By August 1998, just before the start of the remediation, the natural attenuation plume extended from about 50 m downgradient from the infiltration gallery to about 250 m farther downgradient (fig. 9*A*; table 3). The natural attenuation plume is herein delineated by dissolved oxygen concentrations measured in observation wells of less than 1.0 mg/L and total BTEX concentrations exceeding about 10 micrograms per liter.

Research completed at this site by Bennett and others (1993) indicates that the combination of dissolved oxygen and specific conductance was a good indicator of biodegradation processes (also National Research Council, 2000). In this

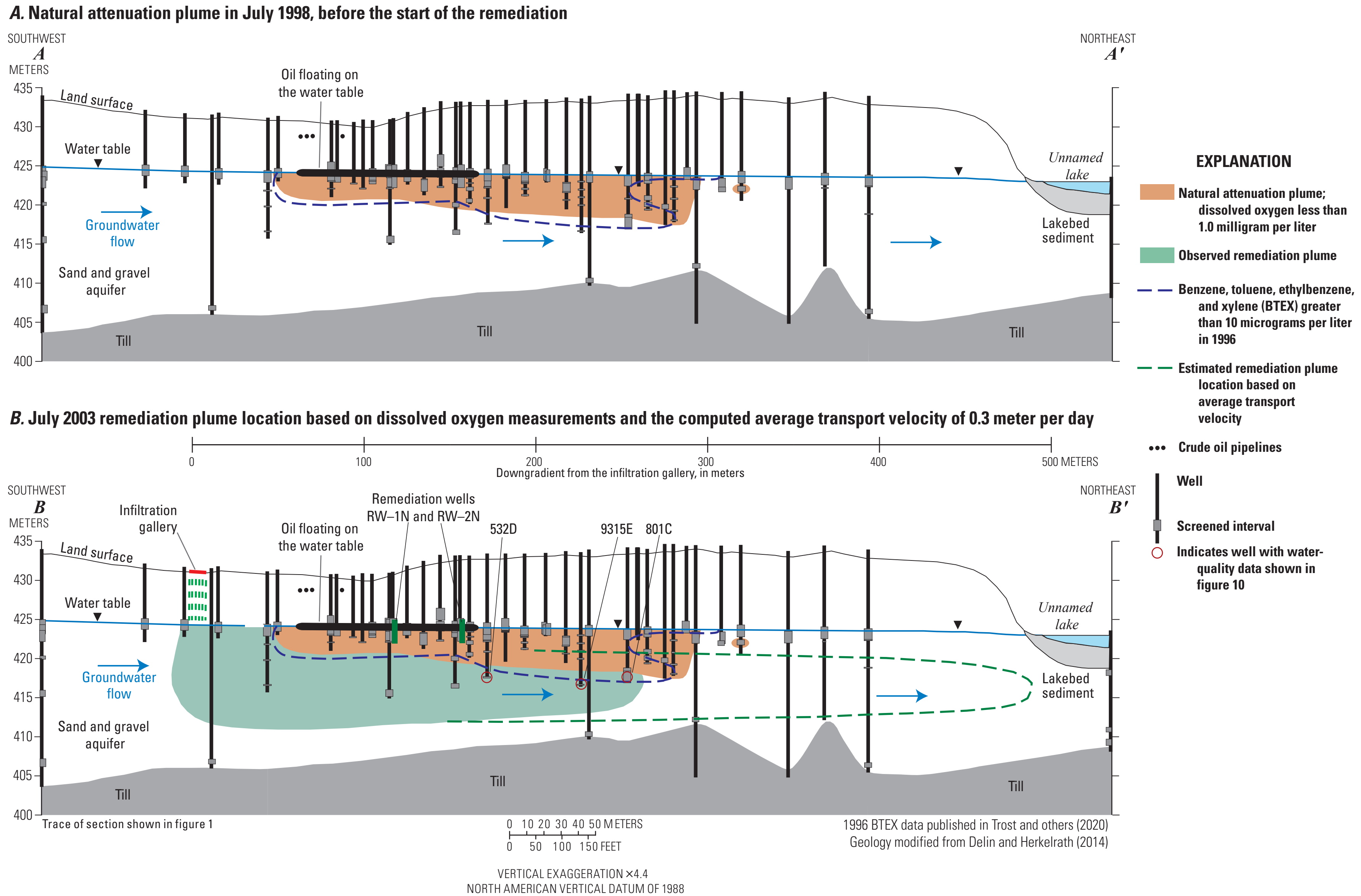


Figure 9. Plumes in the saturated zone at the Bemidji site. *A*, natural attenuation plume in July 1998, before the start of the remediation; *B*, remediation and natural attenuation plumes in July 2003 based on dissolved oxygen measurements and the computed average remediation plume transport velocity of 0.3 meter per day. [Trost and others, 2020; Delin and Herkelrath, 2014]

Table 3. Approximate distance downgradient from the infiltration gallery for the natural attenuation plume compared to estimates for the remediation plume based on observed dissolved oxygen measurements, the maximum observed velocity of 0.9 meter per day based on first arrival of anoxic water 160 meters downgradient from the infiltration gallery, and the average velocity of 0.3 meter per day based on all dissolved oxygen first-arrival data.

[NAP, natural attenuation plume; DO, dissolved oxygen; m/d, meter per day; --, not applicable; ?, location of the NAP and remediation plume were uncertain because of an insufficient number of observation wells downgradient from about 240 meters from the infiltration gallery]

Sampling date	Time (years)[1]	Approximate distance downgradient from the infiltration gallery (meters)			
			For the remediation plume		
		For the NAP	Based on observed DO measurements	Based on maximum velocity of 0.9 m/d	Based on average velocity of 0.3 m/d
August 1998	--	300	--	--	--
July 1999	0.5	300	160	150	50
August 2000	1.6	300	240	510	170
July 2001	2.5	300?	?	840	280
July 2002	3.5	340?	?	1,170	390
July 2003	4.5	340?	?	1,470	490
August 2004[2]	5.6	340?	?	1,830	610

[1]Time, in years, since the beginning of the remediation in January 1999.

[2]This time was 0.6 year after the end of the remediation in December 2003.

study, it was assumed that a dissolved oxygen concentration of less than 1.0 mg/L in groundwater was representative of anoxic conditions in the saturated zone because of microbial biodegradation associated with the crude-oil contamination. By comparison, background dissolved oxygen concentrations typically are in the range of 6–7 mg/L in uncontaminated areas at the site. Similarly, background specific conductance concentrations in groundwater at the site typically range from 300 to 500 µS/cm, which increase to between 500 and 900 µS/cm in areas affected by the crude-oil contamination.

Most of the water injected through the infiltration gallery was intended to be withdrawn by remediation wells RW–1N and RW–2N at the north oil pool (Natural Resources Engineering Company, 1998); however, some of this injected water migrated as a remediation plume of groundwater upgradient from and beneath the existing natural attenuation plume (fig. 9*B*). The total amount of groundwater injected into the infiltration gallery during the remediation is unknown. In July 1999, 6 months after the remediation started, anoxic water was detected for the first time upgradient from and beneath the natural attenuation plume in numerous observation wells. This anoxic water is herein termed the “remediation plume” and was detected as far downgradient as 160 m in July 1999 (table 3); thus, the remediation and natural attenuation plumes seemed to have merged. Without additional data such as isotopes or BTEX concentrations, it was not possible to distinguish between the anoxic waters of the natural attenuation and remediation plumes. The approximate locations of the remediation plume listed in table 3 (and shown in fig. 9*B*) were estimated based on the first detection of anoxic water in the indicated observation wells. Unfortunately, we did not have additional wells in the downgradient areas of the remediation plume to collect groundwater samples and thus more accurately delineate its extent through time. The times listed in table 3 are considered conservative because the anoxic water could have reached a given well before the indicated sampling date.

Based on detection of anoxic water in July 1999 at a location 160 m downgradient from the infiltration gallery, a maximum velocity of 0.9 m/d was computed for the leading edge of the remediation plume for the first 6 months of the remediation. It should be recognized that this rate likely is less than the true maximum rate because our once-per-year sampling frequency was inadequate to detect when the remediation plume first passed any of the wells. The computed rate of 0.9 m/d is slightly greater than the estimated natural lateral pore-water velocity of about 0.7 m/d based on results from previous aquifer hydraulic property analyses completed at the north oil pool (Essaid and others, 2003, 2011). It is hypothesized that this slightly greater rate of lateral plume migration is due to the increased recharge through the infiltration gallery of 73 L/min (38,400 cubic meters per year) over the 37-m^2 surface area of the infiltration gallery for 5 years. This application rate is equivalent to about 1,040 m/yr of recharge applied to the 37-m^2 infiltration gallery, or about 3,000–10,000 times the natural recharge rate of 0.1–0.3 m/yr (Delin and Herkelrath, 2005). The amount pumped from the two north oil pool remediation wells was inadequate to remove all the water injected from remediation wells at the north, middle, and south oil pools. Much of the infiltrating water bypassed the remediation wells and created the remediation plume, as shown in figure 9*B*.

In August 2000, 1.5 years after the remediation started, the remediation plume was detected about 240 m downgradient from the infiltration gallery. This translates to a minimum velocity of 0.4 m/d for the leading edge of the remediation plume based on this single data point. This was the last sampling point where the remediation plume was detected because of an insufficient number of observation wells farther downgradient. After termination of the renewed remediation in December 2003, anoxic conditions persisted beneath the infiltration gallery for about 1.5 years through July 2005 before oxygen concentrations increased in July 2006. The anoxic remediation plume persisted beneath parts of the natural attenuation plume at least through July 2009, 5.5 years after the remediation ended.

Time-series graphs of selected field water-quality data measured in three wells support the hypothesis of the migration of the remediation plume downgradient. Wells 532D, 9315E, and 801C are screened about 15 m below land surface, near the middle of the saturated zone, and within the remediation plume (fig. 9*B*). The locations of these wells are within the predicted downgradient end of the remediation plume (table 3).

Dissolved oxygen decreased in all three wells from between 3 and 4 to less than 1 mg/L during the first 2 years of the remediation, clearly indicating the progressive arrival of the remediation plume at these locations (fig. 10). Between 1999 and 2008, dissolved oxygen concentrations generally remained anoxic, being less than 1 mg/L, at all three locations. In other words, the remediation plume persisted for about 5 years after the remeditation ended as far as 236 m downgradient from the infiltration gallery. The spike in dissolved oxygen for well 801C in 1999 and for 532D in 2007 are due to oxygen being introduced during sampling and are not related to the remediation. Beginning in 2009, 6 years after termination of the remediation, dissolved oxygen concentrations noticeably increased at wells 532D and 9315E, 160 and 214 m, respectively, downgradient from the infiltration gallery. These changes indicate that biodegradation of hydrocarbons in the remediation plume was slowing and less oxygen was being consumed, and the system was transitioning back to its preremediation state.

Beginning in 2000–1, specific conductance concentrations noticeably increased in all three wells from about 400 to more than 700 µS/cm (fig. 10). After reaching a peak concentration in 2002–3, specific conductance concentrations decreased in all three wells. The specific conductance reached preremediation concentrations in wells 532C and 9315E by 2008–10. Similar to the changes in dissolved oxygen concentrations during this period, these changes in specific conductance are the result of the remediation plume migrating downgradient through 2008 followed by dissipation of the remediation plume beginning in 2009 and the system transitioning back to its preremediation state.

In general, pH fluctuated near 7.0 in the three wells before, during, and after the remediation (fig. 10). There was a slight decrease in groundwater pH in all three wells from around 7.2–7.4 units before the start of the remediation in 1998 to 6.8–7.0 units by 2010 (fig. 10). The slight decrease and small fluctuations in pH are unlikely to be related to the remediation, however, but instead are likely related to instrument and sampling variability.

Groundwater temperatures measured in all three wells increased steadily during and after the remediation from about 8–9 °C to 9–10 °C by 2008 (fig. 10). These increasing groundwater temperatures likely reflect migration of the remediation plume downgradient, as further demonstrated by Warren and Bekins (2018).

Warren and Bekins (2018) created a model of subsurface heat generation and transport that helped clarify the contribution of heating from microbial activity and infrastructure, such as the underground pipelines, to observed temperature increases at this site. They created a steady-state, two-dimensional, heat transport model using previously published property values for physical, chemical, and biodegradation properties. Simulated temperature distributions matched the observed average annual temperatures measured in the contaminated area at the site within less than 0.2 °C in the unsaturated zone and 0.4 °C in the saturated zone. The model results confirmed that the observed increased subsurface heat was due primarily to heat from the pipelines and methane oxidation in the unsaturated zone and resulted in an increase of 3.6 °C in average annual temperature.

The insufficient frequency of sample collection, an insufficient number of wells downgradient, and an insufficient number of wells within the remediation plume at deeper depths in the aquifer (fig. 9) prevented us from drawing more wide-ranging conclusions from the field water-quality data. Nevertheless, it is clear these simple, inexpensive, and readily available field water-quality data are useful in evaluating the effects of remediation at a crude-oil spill site.

Estimates of the Remediation Plume Location

Based on the maximum observed velocity of 0.9 m/d, the approximate distance downgradient from the infiltration gallery for the leading edge of the remediation plume was estimated from August 2000 through August 2004 (table 3). Expansion of the remediation plume beyond our most downgradient 240-m observation well sampled in August 2000 likely was affected by several factors. Although the microbial populations were not fully developed at the beginning of the remediation (Bekins and others, 1999), biodegradation is a natural attenuation process that undoubtedly attenuated the remediation plume as it migrated downgradient. The remediation plume also likely expanded in an elliptical pattern because of diffusion and dispersion, and movement of the leading edge slowed down in time. It is likely that expansion of the remediation plume also was affected by variable injection rates in the infiltration gallery and variable pumping rates from the remediation wells.

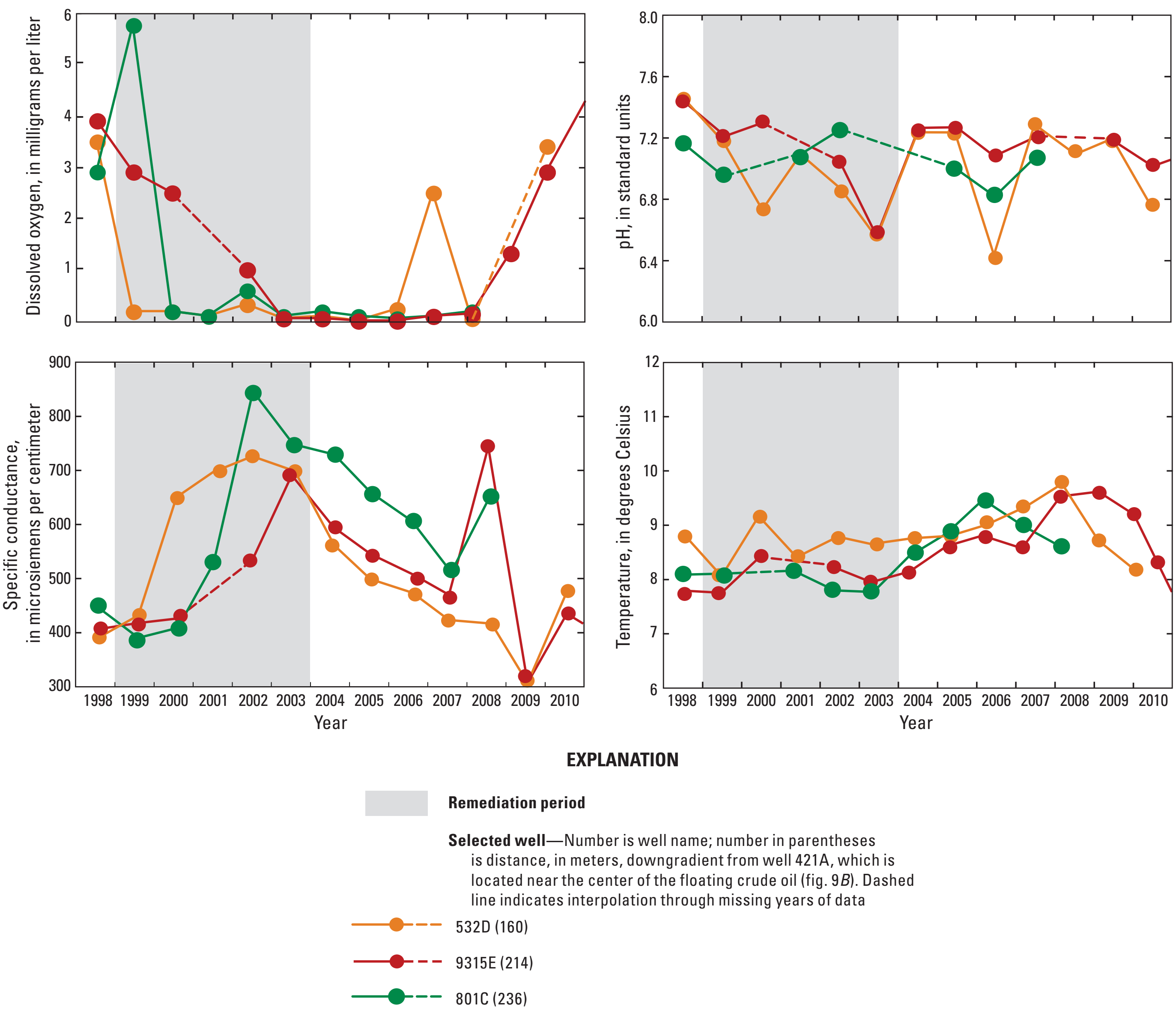


Figure 10. Concentrations of dissolved oxygen, pH, specific conductance, and temperature for selected wells from 1998 through 2010. The locations of these three wells are shown in figure 9*B*.

To account for effects of the previously mentioned processes, the average remediation plume velocity was computed based on data from all the observation wells. This average rate of 0.3 m/d was used as a conservative estimate for the location of the leading edge of the remediation plume for all sampling periods after August 2000 (table 3). Assumptions associated with using this estimate are as follows: (1) the injection rate into the infiltration gallery was constant during the remediation, (2) groundwater recharge and discharge rates remained constant, and (3) biodegradation, diffusion, and dispersion did not substantially attenuate or accelerate movement of the remediation plume beyond this average rate. The actual injection rates into the infiltration gallery were unknown. Based on the average velocity of 0.3 m/d and the previously mentioned assumptions, the remediation plume would have reached a location about 500 m downgradient from the infiltration gallery by July 2003, 5 months before the end of the remediation (table 3; figure 9*B*).

Benzene, Toluene, Ethylbenzene, and Xylene and the Remediation Plume

In 2007, 3.5 years after the remediation ended, the remediation plume was still evident in the flow system at least 240 m downgradient from the infiltration gallery (fig. 10). Crude oil was also observed within the subsurface near the infiltration gallery in 2017 during installation of an observation well. However, BTEX was not detected in association with the remediation plume in 2007 within about 140 m downgradient from the LNAPL source (Amos and others, 2012), which may be an indication of anaerobic BTEX degradation.

Microbial populations associated with the remediation plume likely were not fully developed when the remediation began in 1999, based on data collected at the site by Bekins and others (1999). This would particularly be the case within the less contaminated parts of the unsaturated and saturated zones of the aquifer system beneath the infiltration gallery. It likely took a year or more for the aerobic and anaerobic microbial populations to become established to the point where degradation was noticeable. Modeling by Essaid and others (1995) indicated that the microbial populations in the natural attenuation plume reached their observed values in about 4 years. Degradation likely was rapid in the remediation plume as the microbial populations became established. Results of in situ microcosm experiments (Cozzarelli and others, 2010) indicate that BTEX was almost totally degraded within about 400 days of introduction into the natural attenuation plume where the microbial populations were fully established. Based on these results, it is expected that the BTEX introduced by the disposal of pumped water from the remediation wells into the upgradient infiltration gallery during the remediation would have been fully degraded by natural attenuation by 2007, and probably much sooner. Although groundwater associated with the remediation plume was depleted of BTEX, the water remained anoxic at least through July 2009, 5.5 years after the remediation ended. Instead, the depleted dissolved oxygen that persisted after the remediation ended likely was associated with a plume of nonvolatile dissolved organic carbon at the site, which increased from 1992 until at least 2010 (Amos and others, 2012; Ng and others, 2014; Bekins and others, 2016).

Unsaturated-Zone Vapor

The general hypothesis for vapor transport in this study was that crude-oil removal during the remediation would not have a substantial effect on vapor indicators of biodegradation (methane, carbon dioxide, and oxygen) in the unsaturated zone. This hypothesis resulted in part from the oil-saturation work of Herkelrath (1999), which implied that 75–84 percent of the oil in the subsurface before the start of the remediation would remain after the remediation ended (table 1). Because the estimated remaining source oil was substantial, it was reasonable to hypothesize that vapor transport above the source oil also would not change substantially. Methane and carbon dioxide are produced and oxygen consumed by biodegradation in the capillary zone above the floating crude oil (Chaplin and others, 2002). Consequently, total hydrocarbon biodegradation rates and hydrocarbon concentrations in the unsaturated zone are directly proportional to methane and carbon dioxide gas fluxes and inversely proportional to oxygen gas flux (Chaplin and others, 2002).

The vapor sampling wells (figs. 1, 4, and 11) are spaced somewhat evenly across the north oil pool from well 604G near the upgradient end of the oil. Well 301G is above the center of the oil body, well 601G is farther downgradient and beyond the north oil pool depression, and well 533G is at the downgradient end of the oil pool (figs. 1 and 4). Thus, data from these wells give a good representation of spatial and temporal changes in vapor concentrations across the north oil pool. The data shown in figure 11 generally indicate either no change during the remediation or a continuation of the trend that began before the remediation.

Generally, the trends in vapor concentrations were indicative of long-term (20+ year) oil biodegradation processes rather than remediation activities and support our hypothesis that crude-oil removal would not have a substantial effect on vapor concentrations in the unsaturated zone. There was a general decrease in methane concentrations during and after the remediation in the unsaturated zone above the upgradient, more weathered crude oil near wells 604G, port 3, and 301G, port 4 (fig. 11). At well 301G, port 4, this decrease began in 1997, before the start of the remediation. This decrease is thought to be unrelated to the remediation but instead the result of reduced rates of biodegradation and methane production from the increasingly more weathered crude oil (Amos and others, 2005). The crude oil is much more weathered in this area beneath the north oil pool land-surface depression because of increased recharge that has increased downward transport of microbial growth nutrients to the oil body, thus enhancing oil degradation (Bekins and others, 2005). The increase in methane concentrations at well 601G, port 2, and to a lesser extent at well 533G, port 2, toward the end of the remediation are thought to largely be caused by a natural shift in microbial population from iron-reducing to methanogenic conditions in the downgradient, less weathered parts of the oil (Amos and others, 2012). In general, methane concentrations in the unsaturated zone above the downgradient, less weathered parts of the crude oil near well 533G remained fairly constant during and after the remediation (fig. 11).

Similarly, carbon dioxide, nitrogen, and oxygen concentrations were largely unaffected by the remediation. The slight increase in the nitrogen concentrations at most of the wells plus the decrease in carbon dioxide concentrations at well 601G, port 2, during the remediation likely were due to advective gas flux rather than as a result of the remediation itself (Amos and others, 2005). The decrease in oxygen and carbon dioxide, similar to the slight increase in methane production at well 533G, port 2, is caused by a shift to methanogenic conditions. There was a natural shift in microbial

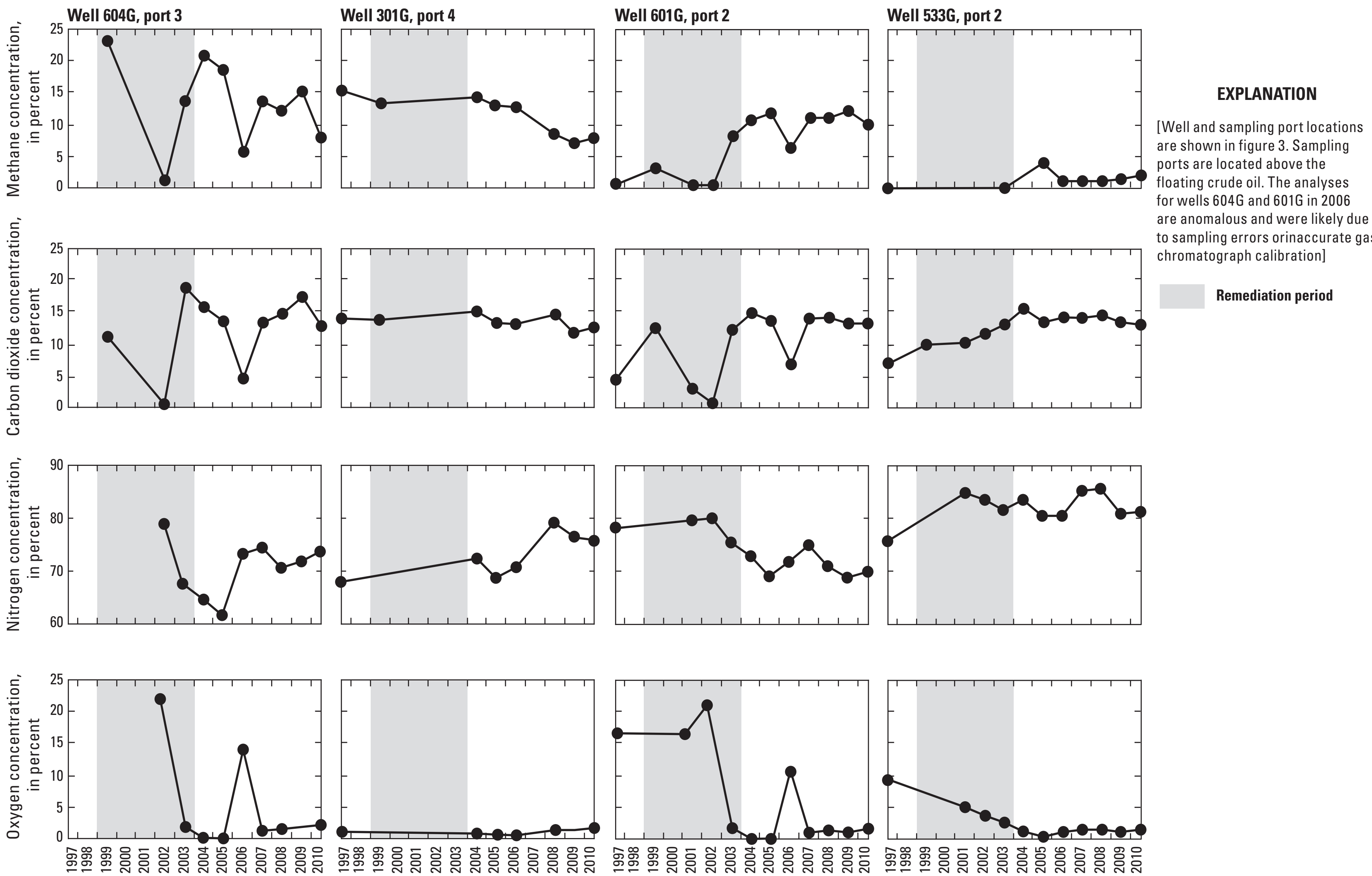


Figure 11. Time series of methane, carbon dioxide, nitrogen, and oxygen vapor concentrations during 1997–2010 for selected vapor sampling ports at the Bemidji, Minnesota, north oil pool, in percentage by volume.

population from iron-reducing to methanogenic conditions in the downgradient, less weathered parts of the oil, as well as a depletion in oxygen associated with degassing caused by methane production (Amos and others, 2005). The analyses of methane, carbon dioxide, and oxygen for wells 604G and 601G in 2006 are anomalous and were likely due to sampling errors or inaccurate GC calibration.

Summary

On August 20, 1979, about 16 kilometers northwest of Bemidji, Minnesota, an 86-centimeter-diameter crude-oil pipeline burst, spilling about 1.7 million liters of crude oil onto glacial outwash deposits. A 1997 investigation by the pipeline company indicated that 575,500 liters of oil remained in the subsurface after their initial remediation efforts. A previous study by Herkelrath in 1999 estimated that 241,000 liters of oil remained at the north and south oil pools and that 7 to 25 percent of the oil in the subsurface could be recovered, based on the concept of residual oil saturation.

Remediation at the Bemidji site was renewed in 1999 at the direction of the Minnesota Pollution Control Agency. Five remediation wells were installed by the pipeline company with the stated objective to remove the crude oil to a sheen in the observation wells. The renewed remediation from 1999 to 2003 resulted in removal of about 115,000 liters of crude oil from the site, which represented 36–41 percent of the 281,000–317,000 liters of oil that was estimated by the U.S. Geological Survey to be present in 1998 before the start of the remediation. The 115,000 liters of oil removed represents only 19 percent of the Natural Resources Engineering Company estimate of 575,500 liters of oil in the subsurface before the start of the remediation.

The objective of reducing oil thickness in wells to a sheen was not achieved. Average oil thickness in 18 wells at the north oil pool increased slightly during the remediation, from about 0.7 meter in 1998, 6 months before the start of the remediation, to about 0.8 meter in 2003, during the last year of the remediation. Average oil thicknesses at the south oil pool remained unchanged at about 0.3 meter. This lack of change or slight increase in average oil thickness, as well as seasonal fluctuations in average oil thickness, do not seem to be linked to the remediation but are more likely the result of natural fluctuations of recharge and discharge from the aquifer. The rebound in crude-oil thicknesses after termination of the remediation observed in the observation wells most likely resulted from lateral migration of the light nonaqueous phase liquid within the capillary zone rather than infiltration from the unsaturated zone.

A negative correlation exists between water-table elevation and crude-oil thickness at many locations at the Bemidji site. The slope of the regression line through these data during the remediation is shallower than for the regression line before or after the remediation. The cause of this reduced slope during the remediation was not examined in detail in this study. The negative correlation between these two datasets was not evident at all wells. Additional research is needed to better clarify the importance and relevance of correlating these data as a tool in evaluating crude-oil contamination and some initial ideas are discussed here.

For all the wells in this report where crude-oil thickness was plotted against water-table elevation, there is a clear vertical offset between the linear regression lines for before the remediation started and after it ended. We concluded that under nonremediation conditions, a vertical shift in the relation between oil thickness and estimated water level indicates a change in the amount of free product in the system, or a change in the properties of the free product. This shift was not apparent when simply calculating the average oil thicknesses across the site.

Another use for these data correlating water-table elevation and crude-oil thickness could be to evaluate how the regression lines rotate in time from before, to during, and after remediation or because of the addition of oil in the case of a pipeline leak. The shallower slope from before compared to during the remediation resulted from the removal of oil. If oil were added to the system, because of a pipeline leak for example, the regression line would similarly have a shallower slope, or be rotated counterclockwise, compared to before the addition of oil.

The remediation expanded the dissolved anoxic plume of groundwater upgradient from and beneath the existing natural attenuation plume. Beginning in 2000–1, for example, specific conductance concentrations noticeably increased in many wells at the north oil pool from about 400 to more than 700 microsiemens per centimeter. The rapid expansion of the anoxic and elevated specific conductance plume indicates that the remediation contributed substantial amounts of biodegradable dissolved organic carbon to groundwater through the infiltration gallery. Anoxic water was detected upgradient from and beneath the natural attenuation plume in numerous observation wells 6 months after the remediation started in January 1999. Based on the detection of anoxic water in July 1999, 160 meters downgradient from the infiltration gallery, a maximum transport rate of 0.9 meter per day was estimated for the leading edge of the remediation plume. This rate is slightly greater than the estimated natural lateral porewater velocity of about 0.7 meter per day based on results from previous hydraulic property analyses at the site (Essaid and others, 2003, 2011). It is hypothesized that this higher rate of lateral plume migration is due to the greatly increased recharge through the infiltration gallery of 73 liters per minute over 37 square meters for 5 years.

The remediation affected most of the field water-quality properties, most notably dissolved oxygen and specific conductance. As mentioned previously, beginning in 2000–1, specific conductance concentrations noticeably increased in many wells at the north oil pool from about 400 to more than 700 microsiemens per centimeter. The trends in vapor data collected before, during, and after the remediation also generally support our hypothesis that crude-oil removal by the pipeline company would not have a substantial effect on vapor concentrations in the unsaturated zone. Although there were some small changes in the concentrations of methane, carbon dioxide, nitrogen, and oxygen, they were not coincident with the beginning or cessation of the remediation and are therefore thought to be the result of other factors affecting biodegradation rates. A decrease in methane concentrations in one representative well, for example, is thought to be the result of reduced rates of biodegradation and methane production from the increasingly more weathered crude oil.

Study results demonstrated that oil-phase recovery at this site is challenging; considerable volumes of mobile and entrapped oil remain in the subsurface despite the remediation efforts. Simple monitoring methods such as measuring field water-quality properties provided an inexpensive approach to evaluating the effects of the remediation. Rapid downgradient migration of the remediation plume likely was due to increased lateral advective flow caused by disposal of water in the infiltration gallery. The anoxic plume persisted beneath parts of the natural attenuation plume at least through July 2009, which was 5.5 years after the remediation ended. Although the remediation plume was expanded, laboratory analyses of water samples collected from wells indicate that the associated benzene, toluene, ethylbenzene, and xylene were fully degraded by 2007, which was 3.5 years after the remediation ended. The lack of benzene, toluene, ethylbenzene, and xylene does not preclude the possibility of other nonvolatile dissolved organic carbon compounds being present in the remediation plume in addition to degradation products. Results similar to those previously mentioned would be expected at crude-oil spill sites with a similar hydrogeologic and climatic setting.

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Appendix 1

Table 1.1. U.S. Geological Survey site identification number, well type, screen elevation, and screen depth below land surface for wells used in this study.

[well type, purpose or use of well; USGS, U.S. Geological Survey; NWIS, National Water Information System; I.D., identifier; m, meter; NAVD 88, North American Vertical Datum of 1988]

Local well number	Well type	USGS NWIS site I.D.	Screen elevation (m above NAVD 88)	Screen depth below land surface (m)
301A	Water and oil	473426095052526	422.79	6.04
310A	Water	473422095053401	422.96	8.47
312	Water and oil	473419095052301	422.71	1.55
315	Water and oil	473419095052530	423.16	5.14
421	Water and oil	473420095052610	420.81	7.84
423	Water and oil	473420095052402	421.25	7.64
528	Water	473420095051916	421.47	10.71
533D	Water and oil	473420095052321	423.12	8.54
954A	Water	473421095051603	421.24	11.43
955A	Water	473421095051501	421.60	11.53
958	Water and oil	473421095052501	422.42	3.91
980	Water and oil	473421095052305	422.70	1.76
301G–01	Vapor	473426095052609	423.02	7.0
301G–02	Vapor	473426095052615	424.02	6.0
301G–03	Vapor	473426095052616	425.02	5.0
301G–04	Vapor	473426095052617	426.02	4.0
301G–05	Vapor	473426095052618	427.02	3.0
301G–06	Vapor	473426095052619	428.02	2.0
301G–07	Vapor	473426095052620	429.02	1.0
301G–08	Vapor	473426095052621	429.52	0.5
518G–01	Vapor	473426095052311	426.01	6.5
518G–02	Vapor	473426095052319	427.01	5.5
518G–03	Vapor	473426095052320	428.01	4.5
518G–04	Vapor	473426095052322	429.01	3.5
518G–05	Vapor	473426095052323	430.01	2.5
518G–06	Vapor	473426095052324	431.01	1.5
518G–07	Vapor	473426095052337	432.01	0.5
530G–01	Vapor	473427095052208	426.28	6.5
530G–02	Vapor	473427095052210	427.28	5.5
530G–03	Vapor	473427095052211	428.28	4.5
530G–04	Vapor	473427095052212	429.28	3.5
530G–05	Vapor	473427095052213	430.28	2.5
530G–06	Vapor	473427095052214	431.28	1.5
530G–07	Vapor	473427095052215	432.28	0.5
531G–01	Vapor	473426095052312	425.88	6.5
531G–02	Vapor	473426095052325	426.88	5.5
531G–03	Vapor	473426095052326	427.88	4.5
531G–04	Vapor	473426095052327	428.88	3.5
531G–05	Vapor	473426095052328	429.88	2.5
531G–06	Vapor	473426095052329	430.88	1.5
531G–07	Vapor	473426095052330	431.88	0.5

Table 1.1. U.S. Geological Survey site identification number, well type, screen elevation, and screen depth below land surface for wells used in this study.—Continued

[well type, purpose or use of well; USGS, U.S. Geological Survey; NWIS, National Water Information System; I.D., identifier; m, meter; NAVD 88, North American Vertical Datum of 1988]

Local well number	Well type	USGS NWIS site I.D.	Screen elevation (m above NAVD 88)	Screen depth below land surface (m)
532G–01	Vapor	473426095052315	425.84	6.5
532G–02	Vapor	473426095052331	426.84	5.5
532G–03	Vapor	473426095052332	427.84	4.5
532G–04	Vapor	473426095052333	428.84	3.5
532G–05	Vapor	473426095052334	429.84	2.5
532G–06	Vapor	473426095052335	430.84	1.5
532G–07	Vapor	473426095052336	431.84	0.5
533G–01	Vapor	473426095052413	425.87	6.5
533G–02	Vapor	473426095052420	426.87	5.5
533G–03	Vapor	473426095052421	427.87	4.5
533G–04	Vapor	473426095052448	428.87	3.5
533G–05	Vapor	473426095052449	429.87	2.5
533G–06	Vapor	473426095052450	430.87	1.5
533G–07	Vapor	473426095052451	431.87	0.5
534G–01	Vapor	473426095052452	425.64	6.5
534G–02	Vapor	473426095052453	426.64	5.5
534G–03	Vapor	473426095052454	427.64	4.5
534G–04	Vapor	473426095052455	428.64	3.5
534G–05	Vapor	473426095052456	429.64	2.5
534G–06	Vapor	473426095052457	430.64	1.5
534G–07	Vapor	473426095052458	431.64	0.5
601G–01	Vapor	473426095052502	425.28	6.5
601G–02	Vapor	473426095052513	426.28	5.5
601G–03	Vapor	473426095052514	427.28	4.5
601G–04	Vapor	473426095052515	428.28	3.5
601G–05	Vapor	473426095052516	429.28	2.5
601G–06	Vapor	473426095052517	430.28	1.5
601G–07	Vapor	473426095052518	431.28	0.5
604G–01	Vapor	473425095052701	423.33	6.5
604G–02	Vapor	473425095052723	424.33	5.5
604G–03	Vapor	473425095052724	425.33	4.5
604G–04	Vapor	473425095052725	426.33	3.5
604G–05	Vapor	473425095052726	427.33	2.5
604G–06	Vapor	473425095052727	428.33	1.5
604G–07	Vapor	473425095052728	429.33	0.5
9101G–01	Vapor	473426095052417	425.47	6.5
9101G–02	Vapor	473426095052431	426.47	5.5
9101G–03	Vapor	473426095052432	427.47	4.5
9101G–04	Vapor	473426095052433	428.47	3.5
9101G–05	Vapor	473426095052434	429.47	2.5
9101G–06	Vapor	473426095052435	430.47	1.5

Table 1.1. U.S. Geological Survey site identification number, well type, screen elevation, and screen depth below land surface for wells used in this study.—Continued

[well type, purpose or use of well; USGS, U.S. Geological Survey; NWIS, National Water Information System; I.D., identifier; m, meter; NAVD 88, North American Vertical Datum of 1988]

Local well number	Well type	USGS NWIS site I.D.	Screen elevation (m above NAVD 88)	Screen depth below land surface (m)
9101G–07	Vapor	473426095052436	430.97	1.0
9101G–08	Vapor	473426095052437	431.47	0.5
9101G–09	Vapor	473426095052438	431.97	0.2
9103G–01	Vapor	473426095052418	425.90	6.5
9103G–02	Vapor	473426095052439	426.90	5.5
9103G–03	Vapor	473426095052440	427.90	4.5
9103G–04	Vapor	473426095052441	428.90	3.5
9103G–05	Vapor	473426095052442	429.90	2.5
9103G–06	Vapor	473426095052443	430.90	1.5
9103G–07	Vapor	473426095052444	431.40	1.0
9103G–08	Vapor	473426095052445	431.90	0.5
9014G–01	Vapor	473426095052504	423.48	7.93
9014G–02	Vapor	473426095052519	423.78	7.63
9014G–03	Vapor	473426095052520	424.08	7.33
9014G–04	Vapor	473426095052521	424.48	6.93
9014G–05	Vapor	473426095052522	425.48	5.93
9014G–06	Vapor	473426095052523	426.48	4.93
9014G–07	Vapor	473426095052524	427.48	3.93
9014G–08	Vapor	473426095052525	428.48	2.93
9015G–01	Vapor	473425095052506	424.91	6.5
9015G–02	Vapor	473425095052522	425.91	5.5
9015G–03	Vapor	473425095052524	426.91	4.5
9015G–04	Vapor	473425095052525	427.91	3.5
9015G–05	Vapor	473425095052526	428.91	2.5
9015G–06	Vapor	473425095052527	429.41	2.0
9015G–07	Vapor	473425095052528	429.91	1.5
9015G–08	Vapor	473425095052529	430.41	1.0
9016G–01	Vapor	473425095052613	423.61	6.0
9016G–02	Vapor	473425095052616	424.61	5.0
9016G–03	Vapor	473425095052617	425.61	4.0
9016G–04	Vapor	473425095052618	426.61	3.0
9016G–05	Vapor	473425095052619	427.61	2.0
9016G–06	Vapor	473425095052620	428.11	1.5
9016G–07	Vapor	473425095052621	428.61	1.0
9016G–08	Vapor	473425095052622	429.11	0.5

Table 1.1. U.S. Geological Survey site identification number, well type, screen elevation, and screen depth below land surface for wells used in this study.—Continued

[well type, purpose or use of well; USGS, U.S. Geological Survey; NWIS, National Water Information System; I.D., identifier; m, meter; NAVD 88, North American Vertical Datum of 1988]

Local well number	Well type	USGS NWIS site I.D.	Screen elevation (m above NAVD 88)	Screen depth below land surface (m)
9017G–01	Vapor	473425095052703	423.74	5.9
9017G–02	Vapor	473425095052716	424.74	4.9
9017G–03	Vapor	473425095052717	425.74	3.9
9017G–04	Vapor	473425095052718	426.74	2.9
9017G–05	Vapor	473425095052719	427.24	2.4
9017G–06	Vapor	473425095052720	427.74	1.9
9017G–07	Vapor	473425095052721	428.74	0.9
9017G–08	Vapor	473425095052722	429.74	0.4

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