Transportation Research Board
Special Report 311

Effects of Diluted Bitumen on Crude Oil Transmission Pipelines

Prepublication Copy • Uncorrected Proofs

NATIONAL RESEARCH COUNCIL

Transportation Research Board
Special Report 311

Effects of Diluted Bitumen on Crude Oil Transmission Pipelines

Committee for a Study of Pipeline Transportation of Diluted Bitumen

Transportation Research Board

Board on Energy and Environmental Systems

Board on Chemical Sciences and Technology

NATIONAL RESEARCH COUNCIL
OF THE NATIONAL ACADEMIES

Transportation Research Board
Washington, D.C.
2013
www.TRB.org

Transportation Research Board Special Report 311

Subscriber Categories
Energy; freight transportation; pipelines; policy; terminals and facilities

Transportation Research Board publications are available by ordering individual publications directly from the TRB Business Office, through the Internet at www.TRB.org or national-academies.org/trb, or by annual subscription through organizational or individual affiliation with TRB. Affiliates and library subscribers are eligible for substantial discounts. For further information, contact the Transportation Research Board Business Office, 500 Fifth Street, NW, Washington, DC 20001 (telephone 202-334-3213; fax 202-334-2519; or e-mail TRBsales@nas.edu).

NOTICE: The project that is the subject of this report was approved by the Governing Board of the National Research Council, whose members are drawn from the councils of the National Academy of Sciences, the National Academy of Engineering, and the Institute of Medicine. The members of the committee responsible for the report were chosen for their special competencies and with regard for appropriate balance.

This report has been reviewed by a group other than the authors according to the procedures approved by a Report Review Committee consisting of members of the National Academy of Sciences, the National Academy of Engineering, and the Institute of Medicine.

This report was sponsored by the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation.

Library of Congress Cataloging-in-Publication Data

ISBN 978-0-309-28675-6

THE NATIONAL ACADEMIES

Advisers to the Nation on Science, Engineering, and Medicine

The **National Academy of Sciences** is a private, nonprofit, self-perpetuating society of distinguished scholars engaged in scientific and engineering research, dedicated to the furtherance of science and technology and to their use for the general welfare. On the authority of the charter granted to it by the Congress in 1863, the Academy has a mandate that requires it to advise the federal government on scientific and technical matters. Dr. Ralph J. Cicerone is president of the National Academy of Sciences.

The **National Academy of Engineering** was established in 1964, under the charter of the National Academy of Sciences, as a parallel organization of outstanding engineers. It is autonomous in its administration and in the selection of its members, sharing with the National Academy of Sciences the responsibility for advising the federal government. The National Academy of Engineering also sponsors engineering programs aimed at meeting national needs, encourages education and research, and recognizes the superior achievements of engineers. Dr. Charles M. Vest is president of the National Academy of Engineering.

The **Institute of Medicine** was established in 1970 by the National Academy of Sciences to secure the services of eminent members of appropriate professions in the examination of policy matters pertaining to the health of the public. The Institute acts under the responsibility given to the National Academy of Sciences by its congressional charter to be an adviser to the federal government and, on its own initiative, to identify issues of medical care, research, and education. Dr. Harvey V. Fineberg is president of the Institute of Medicine.

The **National Research Council** was organized by the National Academy of Sciences in 1916 to associate the broad community of science and technology with the Academy's purposes of furthering knowledge and advising the federal government. Functioning in accordance with general policies determined by the Academy, the Council has become the principal operating agency of both the National Academy of Sciences and the National Academy of Engineering in providing services to the government, the public, and the scientific and engineering communities. The Council is administered jointly by both Academies and the Institute of Medicine. Dr. Ralph J. Cicerone and Dr. Charles M. Vest are chair and vice chair, respectively, of the National Research Council.

The **Transportation Research Board** is one of six major divisions of the National Research Council. The mission of the Transportation Research Board is to provide leadership in transportation innovation and progress through research and information exchange, conducted within a setting that is objective, interdisciplinary, and multimodal. The Board's varied activities annually engage about 7,000 engineers, scientists, and other transportation researchers and practitioners from the public and private sectors and academia, all of whom contribute their expertise in the public interest. The program is supported by state transportation departments, federal agencies including the component administrations of the U.S. Department of Transportation, and other organizations and individuals interested in the development of transportation. **www.TRB.org**

www.national-academies.org

Transportation Research Board 2013 Executive Committee*

* Membership as of June 2013.

Board on Energy and Environmental Systems

Members

Andrew Brown, Jr., NAE, Delphi Corporation, Troy, Michigan, *Chair*
William F. Banholzer, NAE, Dow Chemical Company, Midland, Michigan
William Cavanaugh III, NAE, Progress Energy (retired), Raleigh, North Carolina
Paul A. DeCotis, Long Island Power Authority, Albany, New York
Christine Ehlig-Economides, NAE, Texas A&M University, College Station
Sherri Goodman, CNA, Alexandria, Virginia
Narain G. Hingorani, NAE, Independent Consultant, San Mateo, California
Robert Huggett, Independent Consultant, Seaford, Virginia
Debbie Niemeier, University of California, Davis
Daniel Nocera, NAS, Massachusetts Institute of Technology, Cambridge
Margo Oge, Environmental Protection Agency (retired), McLean, Virginia
Michael Oppenheimer, Princeton University, Princeton, New Jersey
Jackalyne Pfannenstiel, Independent Consultant, Piedmont, California
Dan Reicher, Stanford University, Stanford, California
Bernard Robertson, NAE, Daimler-Chrysler (retired), Bloomfield Hills, Michigan
Gary Rogers, FEV, Inc., Auburn Hills, Michigan
Alison Silverstein, Consultant, Pflugerville, Texas
Mark Thiemens, NAS, University of California, San Diego
Richard White, Oppenheimer & Company, New York City
Adrian Zaccaria, NAE, Bechtel Group (retired), Frederick, Maryland

Staff

James Zucchetto, Senior Board/Program Director
Dana Caines, Financial Associate
David W. Cooke, Associate Program Officer
Alan Crane, Senior Scientist
K. John Holmes, Senior Program Officer/Associate Director
LaNita Jones, Administrative Coordinator
Alice V. Williams, Senior Program Assistant
Jonathan Yanger, Senior Project Assistant

Board on Chemical Sciences and Technology

Members

Pablo G. Debenedetti, NAS/NAE, Princeton University, New Jersey, *Cochair*
Timothy Swager, NAS, Massachusetts Institute of Technology, Cambridge, *Cochair*
David Bem, The Dow Chemical Company, Midland, Michigan
Robert G. Bergman, NAS, University of California, Berkeley
Joan Brennecke, NAE, University of Notre Dame, Indiana
Henry E. Bryndza, E. I. du Pont de Nemours & Company, Wilmington, Delaware
David W. Christianson, University of Pennsylvania, Philadelphia
Richard Eisenberg, NAS, University of Rochester, New York
Mary Jane Hagenson, Chevron Phillips Chemical Company LLC (retired), The Woodlands, Texas
Carol J. Henry, The George Washington University, Washington, D.C.
Jill Hruby, Sandia National Laboratories, Albuquerque, New Mexico
Michael Kerby, ExxonMobil Chemical Company, Baytown, Texas
Charles E. Kolb, Aerodyne Research, Inc., Billerica, Massachusetts
Sander G. Mills, Merck, Sharp, & Dohme Corporation, Kenilworth, New Jersey
David Morse, NAE, Corning Incorporated, Corning, New York
Robert E. Roberts, Institute for Defense Analyses, Alexandria, Virginia
Darlene Solomon, Agilent Technologies, Santa Clara, California
Jean Tom, Bristol-Myers Squibb, West Windsor, New Jersey
David Walt, NAE, Tufts University, Medford, Massachusetts

Staff

Dorothy Zolandz, Director
Kathryn Hughes, Senior Program Officer
Douglas Friedman, Program Officer
Amanda Khu, Administrative Assistant
Rachel Yancey, Senior Program Assistant

Committee for a Study of Pipeline Transportation of Diluted Bitumen

Mark A. Barteau, NAE, University of Michigan, Ann Arbor, *Chair*
Y. Frank Cheng, University of Calgary, Alberta, Canada
James F. Dante, Southwest Research Institute, San Antonio, Texas
H. Scott Fogler, University of Michigan, Ann Arbor
O. B. Harris, O. B. Harris, LLC, Missouri City, Texas
Brenda J. Little, Naval Research Laboratory, Stennis Space Center, Mississippi
Mohammad Modarres, University of Maryland, College Park
W. Kent Muhlbauer, WKM Consultancy, LLC, Austin, Texas
Srdjan Nešić, Ohio University, Athens
Joe H. Payer, University of Akron, Ohio
Richard A. Rabinow, Rabinow Consortium, LLC, Houston, Texas
George W. Tenley, Jr., Hedgesville, West Virginia

National Research Council Staff

Thomas R. Menzies, Jr., Study Director, Transportation Research Board
Douglas Friedman, Program Officer, Board on Chemical Sciences and Technology
Claudia Sauls, Senior Program Assistant, Transportation Research Board

Preface

This National Research Council (NRC) study was sponsored by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation.[1] The study charge and origins are explained in Chapter 1. The contents and findings of the report represent the consensus effort of a committee of technical experts, who served uncompensated in the public interest. Drawn from multiple disciplines, the members brought expertise from chemistry and chemical engineering; corrosion and materials science; risk analysis; and pipeline operations, research, and safety regulation. Committee member biographical information is provided at the end of the report.

The study committee convened five times over 10 months, including a visit by several members to a pipeline terminal and energy research laboratory in the Edmonton and Fort McMurray areas of Alberta, Canada. Data-gathering activities during and between meetings were extensive. All but the final meeting contained sessions open to the public. During meetings, the committee heard from speakers from the oil and pipeline industries, environmental interest groups, research and standards organizations, oil testing companies, and government agencies from the United States and Canada. The committee also provided a forum for private individuals to contribute information relevant to the study. In sum, more than 40 people spoke before the committee during public meetings and site visits. To obtain additional information on the practice of transporting diluted bitumen by pipeline, the committee provided the Canadian Energy Pipeline Association with a questionnaire for distribution to pipeline operators with experience transporting diluted bitumen and other crude oils in North America. The questionnaire responses and agendas for the public meetings are provided in appendices to this report.

ACKNOWLEDGMENTS

The committee thanks the many individuals who contributed to its work.

During data-gathering sessions open to the public, the committee met with the following officials from PHMSA: Jeffrey Wiese, Associate Administrator; Linda Daugherty, Deputy Associate Administrator for Policy and Programs; Alan Mayberry, Deputy Associate Administrator for Field Operations; Blaine Keener, National Field Coordinator; and Jeffery Gilliam, Senior Engineer and Project Manager. The contributions of all were appreciated, especially those of Mr. Gilliam, who served as PHMSA's technical representative for the project.

Several officials and researchers from government agencies and laboratories in Canada briefed the committee during meetings: Iain Colquhoun, National Energy Board; John Zhou, Alberta Innovates Energy and Environment Solutions; Haralampos Tsaprailis and Michael Mosher, Alberta Innovates Technology Futures; and Parviz Rahimi, Heather Dettman, and Sankara Papavinasam, Natural Resources Canada. The committee thanks them all, especially Dr. Papavinasam, who twice briefed the committee, and Dr. Tsaprailis, who arranged a tour of the Alberta Innovates and Natural Resources Canada energy laboratory in Devon, Alberta.

[1] The contract was awarded on March 12, 2012.

Early in its deliberations, the committee invited several nationally recognized experts to provide briefings on pipeline design, operations, and maintenance; corrosion evaluation and control; and developments in the North American petroleum market. The committee is indebted to Thomas O. Miesner, Pipeline Knowledge and Development; Arthur Diefenbach, Westpac Energy Group; Oliver Moghissi, DNV Columbus, Inc.; and Geoffrey Houlton, IHS. Their uncompensated briefings provided essential background for the committee's work.

The committee met with and received information from the following individuals representing the oil production and pipeline industries: Dale McIntyre, ConocoPhillips; Randy Segato, Suncor Energy, Inc.; Dennis Sutton, Marathon Petroleum Company; Bruce Dupuis, Jenny Been, and Bruce Wascherol, TransCanada Corporation; Colin Brown, Kinder Morgan Canada; Terri Funk and Shoaib Nasin, Inter Pipeline; and Trevor Place, Ashok Anand, Martin DiBlasi, and Scott Ironside, Enbridge Pipelines, Inc. The committee expresses its gratitude to all, especially to Mr. Ironside, who assisted in arranging presentations and the tour of a pipeline terminal in Alberta.

In seeking information on the properties of diluted bitumen and other crude oils, the committee received valuable information from the following individuals and organizations: Harry Giles, Crude Oil Quality Association; Bill Lywood, Crude Quality, Inc.; and Andre Lemieux, Canadian Crude Quality Technical Association. The information received on the chemical and physical properties of diluted bitumen and other crude oils was critical to many of the analyses in the study. The committee thanks each of them and their organizations for this assistance.

Finally, the committee thanks several individuals who briefed it or were otherwise helpful in identifying issues and providing relevant sources of data and other information. They are Anthony Swift, Natural Resources Defense Council; Peter Lidiak, American Petroleum Institute; Cheryl Trench, Allegro Energy Consulting; and Ziad Saad, Canadian Energy Pipeline Association. Mr. Saad was instrumental in distributing and collecting responses to the pipeline operator questionnaire.

Thomas R. Menzies and Douglas Friedman were the principal project staff. Menzies managed the study and drafted much of the report under the guidance of the committee and the supervision of Stephen R. Godwin, Director, Studies and Special Programs, Transportation Research Board (TRB). Additional technical assistance and oversight were provided by James Zucchetto, Director of the Board on Energy and Environmental Systems, and Dorothy Zolandz, Director of the Board on Chemical Sciences and Technology. Norman Solomon edited the report, and Jennifer J. Weeks prepared the edited manuscript for prepublication web posting, under the supervision of Javy Awan, Director of Publications, TRB. Claudia Sauls provided extensive support to the committee in arranging its meetings and managing documents.

The report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise in accordance with procedures approved by NRC's Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the institution in making the report as sound as possible and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process.

NRC thanks the following individuals for their review of this report: Khalid Aziz (NAE), Stanford University; John Beavers, DNV Columbus, Inc.; Jos Derksen, University of Alberta; Melvin F. Kanninen (NAE), MFK Consulting Services; John Kiefner, Kiefner & Associates,

Inc.; Thomas Miesner, Pipeline Knowledge and Development; Gene Nemanich, Chevron Technology Ventures (retired); Stephen Pollock (NAE), University of Michigan; Massoud Tahamtani, Commonwealth of Virginia State Corporation Commission; and Patrick Vieth, Dynamic Risk USA, Inc. The review of this report was overseen by Elisabeth Drake (NAE), Massachusetts Institute of Technology, and Susan Hanson (NAS), Clark University. Appointed by NRC, they were responsible for making certain that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of the report rests solely with the authoring committee and the institution. Karen Febey managed the report review process under the supervision of Suzanne Schneider, Associate Executive Director, TRB.

Contents

Executive Summary

Legislation enacted in January 2012 called on the Secretary of Transportation to determine whether any increase in the risk of a release exists for pipelines transporting diluted bitumen.[1] Bitumen is a dense and viscous form of petroleum that will flow in unheated pipelines only when it is diluted with lighter oils. The source of the diluted bitumen in North America is the oil sands region of Alberta, Canada. Diluted bitumen has been imported from Canada for more than 30 years and is currently transmitted through numerous pipelines in the United States. As imports of this and other Canadian crude oils have grown, new U.S. pipelines have been constructed, the flow directions of several existing pipelines have been reversed, and additional pipeline capacity is planned.

Determination of the risk of a pipeline release requires an assessment of both the likelihood and the consequences of a release. To inform its review of the former, the U.S. Department of Transportation asked the National Research Council to convene an expert committee to study whether shipments of diluted bitumen differ sufficiently from shipments of other crude oils in such a way as to increase the likelihood of releases from transmission pipelines. A finding of increased likelihood would lead the committee to conduct a follow-up review of the adequacy of federal pipeline safety regulations. In the absence of such a finding, the committee was tasked with issuing this final report, which documents the study approach and results.

STUDY APPROACH

The committee analyzed information in a variety of forms. Early in its deliberations, the committee provided a public forum for individuals to contribute information relevant to the study. The committee reviewed pipeline incident statistics and investigations; examined data on the chemical and physical properties of shipments of diluted bitumen and other crude oils; reviewed the technical literature; consulted experts in pipeline corrosion, cracking, and other causes of releases; and queried pipeline operators about their experience in transporting diluted bitumen.

The review of incident data revealed the ways in which transmission pipelines fail. Some failures can be affected by the properties of the transported crude oil, such as its water and sediment content, viscosity and density, and chemical composition. These properties were examined for diluted bitumen and a range of other crude oils to determine whether pipelines transporting diluted bitumen are more likely to experience releases. In addition, the committee considered whether pipeline operations and maintenance (O&M) practices, including internal and external corrosion control capabilities, are subject to changes that inadvertently increase the likelihood of release when pipelines transport diluted bitumen.

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

RESULTS

Central Findings

The committee does not find any causes of pipeline failure unique to the transportation of diluted bitumen. Furthermore, the committee does not find evidence of chemical or physical properties of diluted bitumen that are outside the range of other crude oils or any other aspect of its transportation by transmission pipeline that would make diluted bitumen more likely than other crude oils to cause releases.

Specific Findings

Diluted bitumen does not have unique or extreme properties that make it more likely than other crude oils to cause internal damage to transmission pipelines from corrosion or erosion. Diluted bitumen has density and viscosity ranges that are comparable with those of other crude oils. It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and operating temperature. The amount and size of solid particles in diluted bitumen are within the range of other crude oils and do not create an increased propensity for deposition or erosion. Shipments of diluted bitumen do not contain higher concentrations of water, sediment, dissolved gases, or other agents that cause or exacerbate internal corrosion, including microbiologically influenced corrosion. The organic acids in diluted bitumen are not corrosive to steel at pipeline operating temperatures.

Diluted bitumen does not have properties that make it more likely than other crude oils to cause damage to transmission pipelines from external corrosion and cracking or from mechanical forces. The contents of a pipeline can contribute to external corrosion and cracking by causing or necessitating operations that raise the temperature of a pipeline, produce higher internal pressures, or bring about more fluctuation in pressure. There is no evidence that operating temperatures and pressures are higher or more likely to fluctuate when pipelines transport diluted bitumen than when they transport other crude oils of similar density and viscosity. Furthermore, the transportation of diluted bitumen does not differ from that of other crude oils in ways that can lead to conditions that cause mechanical damage to pipelines.

Pipeline O&M practices are the same for shipments of diluted bitumen as for shipments of other crude oils. O&M practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change their O&M practices in transporting diluted bitumen.

In accordance with the study charge, these results focus on whether pipeline shipments of diluted bitumen have a likelihood of release greater than that of other crude oils. As indicated at the outset of this summary, the committee was not asked or constituted to study whether pipeline releases of diluted bitumen and other crude oils differ in consequences or to determine whether such a study is warranted. Accordingly, the report does not address these questions and should not be construed as having answered them.

Introduction

This chapter describes the study charge and scope, analytic approach, and report structure.

STUDY CHARGE

Section 16 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 calls for the Secretary of Transportation to "complete a comprehensive review of hazardous liquid pipeline facility regulations to determine whether the regulations are sufficient to regulate pipeline facilities used for the transportation of diluted bitumen. In conducting the review, the Secretary shall conduct an analysis of whether any increase in the risk of a release exists for pipeline facilities transporting diluted bitumen."[1]

Bitumen is a dense and viscous form of petroleum that will flow through unheated pipelines only when it is diluted with lighter oils. At present, the source of bitumen supplied to refineries in North America is the oil sands region of Alberta, Canada. Bitumen from Canada has been diluted for pipeline transportation to the United States for more than 30 years, primarily to refineries located along the Great Lakes and elsewhere in the Midwest. Bitumen production and imports from Canada have grown during the past decade, and this traditional U.S. oil-processing market no longer has the capacity to refine all of the supply. Meanwhile, refineries on the Gulf Coast, which have traditionally processed South American and Mexican crude oils with properties similar to bitumen, have sought access to the heavy crude oils from Canada. To accommodate the Canadian imports as well as the growth in domestic crude oil production, the flow directions of several existing pipelines have been reversed, new transmission pipelines have been constructed, and additional pipeline capacity is planned.

Within the U.S. Department of Transportation (USDOT), the regulation of pipeline safety resides with the Pipeline and Hazardous Materials Safety Administration (PHMSA). USDOT has thus delegated to PHMSA the responsibility of determining whether pipelines transporting diluted bitumen have an increased risk of release. A determination of risk requires an assessment of both the likelihood and the consequences of a release. To inform its assessment of the former, PHMSA contracted with the National Research Council (NRC) to conduct the study documented in this report. Specifically, PHMSA asked NRC to convene a committee of experts in pipeline operations; risk analysis; safety regulation; and chemical, materials, and corrosion engineering to "analyze whether transportation of diluted bitumen by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils." PHMSA did not ask NRC to study the consequences of potential pipeline releases of diluted bitumen.

The full statement of task (SOT) for the study is contained in Box 1-1. The SOT calls for a two-phase study, with the conduct of the second phase contingent on the outcome of the first. In the first phase, the study committee is asked to examine whether shipments of diluted bitumen can affect transmission pipelines and their operations so as to increase the likelihood of release

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

Box 1-1

Statement of Task

The committee will analyze whether transportation of diluted bitumen (dilbit) by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils. Should the committee conclude that an increased likelihood of release exists, it will review the federal hazardous liquid pipeline facility regulations to determine whether they are sufficient to mitigate the increased likelihood of release.

In the first phase of the project, the committee will examine whether dilbit can affect transmission pipelines and their operations so as to create an increased likelihood of release when compared with other crude oils transported through pipelines. Should the committee conclude there is no increased likelihood of release or find there is insufficient information to reach such a conclusion, a second phase of the project will not be required and the committee will prepare a final report to the Office of Pipeline Safety (OPS) of the Pipeline and Hazardous Materials Safety Administration (PHMSA). This report may include recommendations for improving information to assess the likelihood of failure.

Should the committee conclude there is an increased likelihood of release on the basis of dilbit's effects on transmission pipelines and their operations, it will issue a brief Phase 1 report of its findings and then proceed to the second phase of the project to determine whether hazardous liquids pipeline regulations are sufficient to mitigate the increased likelihood of release. The committee's final report following completion of this second phase will contain the complete set of findings, conclusions, and recommendations of both project phases.

when compared with shipments of other crude oils transported by pipeline. In the potential second phase—to be undertaken only in case of a finding of increased likelihood—the committee is asked to review federal pipeline safety regulations to determine whether they are sufficient to mitigate an increased likelihood of release from diluted bitumen. If the committee does not find an increased likelihood of release or the information available is insufficient for a finding, the committee is expected to prepare a final report documenting the study approach and results.

STUDY SCOPE

The SOT makes reference to several terms that delineate the study scope and require explication. First, the SOT specifically requests an examination of "transmission" pipeline facilities. The pipelines in these facilities contain large-capacity pipe, usually 20 inches or more in diameter, and generally transport fluids over long distances under relatively high pressure (400 to 1,400 pounds per square inch). Transmission facilities also contain storage tanks, pumping equipment, and piping within terminals. Gathering pipelines used for collecting crude oil from production fields do not transport diluted bitumen in the United States and are not part of this study.

As used in the SOT, the term "diluted bitumen" does not define a single product composition or specific set of product or shipment properties. Blending bitumen with lighter oils to lower viscosity is the common method of transporting this form of petroleum by pipeline. The volume of bitumen in a pipeline shipment will vary with the diluent, as will the chemical and physical properties of the shipment. The Canadian diluted bitumen transported in transmission pipelines to the United States generally contains 50 to 75 percent bitumen by volume, with light oils constituting the remainder. These bitumen blends are the subject of this study. It is recognized that the source and composition of bitumen shipments may change depending on technological advances, diluent supplies, refinery demands, and other technical and economic developments.

Finally, the SOT asks the committee to examine whether pipelines transporting diluted bitumen have a higher likelihood of release than pipelines transporting "other crude oils." Accordingly, the aim of this study is to determine whether shipments of diluted bitumen have a release history or specific properties associated with pipeline failures that lie outside the range of experience and properties represented by the full spectrum of crude oils transported by pipeline in the United States.

ANALYTIC APPROACH

An assessment of release likelihood requires information on the potential sources of pipeline failure. PHMSA mandates the reporting of releases from U.S. transmission pipelines and categorizes each according to its immediate, or proximate, cause. Historically, about one-third of reported releases have involved corrosion damage (Figure 1-1). Other causes include outside force damage, such as an excavator striking a buried pipe, and faulty equipment, operator error, and deficiencies in welds and materials used in pipeline manufacturing and installation.

The committee reviewed U.S. and Canadian data on reported pipeline releases. The review provided insight into the main causes of releases, but the incident statistics alone could not be used to determine whether pipelines are more likely to experience releases when they transport diluted bitumen than when they transport other crude oils. Few incident records contain information on the type of crude oil released in an incident or document the properties of the shipments moved through the pipeline over time. Causal details are also limited. Incidents categorized as corrosion damage, for example, do not specify whether the damage occurred as a result of the action of microorganisms, in combination with stress cracking, or at sites of previous mechanical damage. Such detailed information is important in determining the causative role of the crude oils being transported in the pipeline, particularly for failures arising from cumulative and time-dependent degradation mechanisms such as corrosion and cracking.

Having identified the main causes of pipeline releases, the committee assessed each cause with respect to its potential to be affected by the chemical and physical properties of the transported crude oil. Consideration was given to specific shipment properties that can contribute to internal degradation, external degradation, and mechanical damage in pipelines. While the committee did not perform its own testing of crude oil shipments, information on many of the chemical and physical properties of diluted bitumen and other crude oils was obtained from public websites and assay sheets. Additional information was obtained from a review of government reports and technical literature, queries of oil producers and pipeline

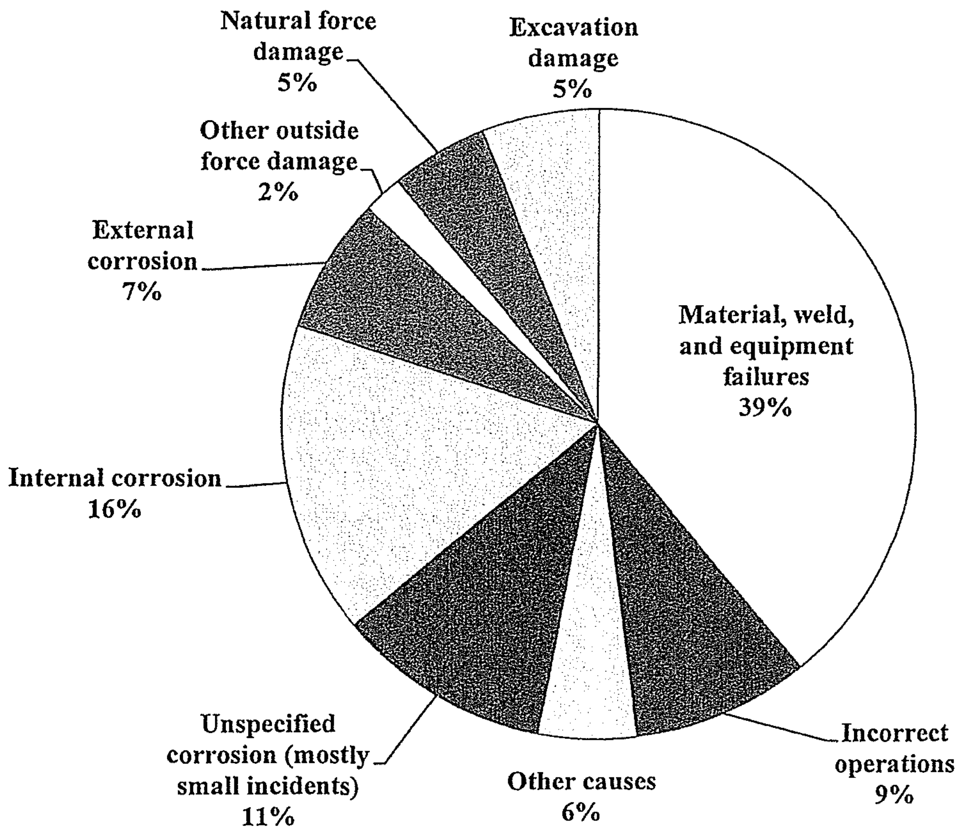

FIGURE 1-1 Causes of crude oil pipeline releases reported to PHMSA, 2002 to 2011. (Source: Incident data provided to committee by PHMSA Office of Pipeline Safety during presentations on October 23, 2012. http://onlinepubs.trb.org/onlinepubs/dilbit/Keener102312.pdf.)

operators, field visits, and inferences from secondary sources such as the maximum water and sediment content specified in pipeline tariffs. The committee then compared the relevant properties of diluted bitumen with the range of properties observed in other crude oils and looked for instances in which diluted bitumen fell outside or at an extreme end of the range.

Recognizing the possibility that some pipeline operators may modify their operating and maintenance practices when they transport diluted bitumen, the committee asked operators about their procedures in transporting diluted bitumen and other crude oils. The committee looked for evidence of changes in standard procedures, including corrosion monitoring and control practices, that could inadvertently make pipelines more susceptible to failure.

REPORT ORGANIZATION

The remainder of the report is organized into five chapters. Chapter 2 provides background on the transportation of crude oil by pipeline, including the main components of pipeline systems and common aspects of their operations and maintenance. Chapter 3 describes the production, properties, and pipeline transportation of diluted bitumen. Chapter 4 reviews pipeline incident data from the United States and Canada. The analyses of how the comparative properties of diluted bitumen and other crude oils pertain to sources of pipeline failure are carried out in Chapter 5. Chapter 6 summarizes the main discussion points from the preceding chapters and presents the study results.

Appendix A contains the questionnaire developed for pipeline operators and the responses. A brief description of the federal hazardous liquid pipeline regulations and PHMSA safety oversight is provided in Appendix B. Agendas from the information-gathering sessions of committee meetings are provided in Appendix C.

2

Crude Oil Pipelines in the United States

This chapter provides background on the network of crude oil transmission pipelines in the United States; the main components of these systems; and common aspects of their operations, maintenance, and integrity management. The background was derived from several sources: National Petroleum Council 2011, Argonne National Laboratory 2008, Rabinow 2004, and a presentation to the committee by Thomas Miesner.[1]

NATIONAL PIPELINE NETWORK

Crude oil is transported, both onshore and offshore, in gathering systems and transmission pipelines. The gathering systems are made up of low-capacity pipelines—typically less than 8 inches in diameter—that move crude oil from wells to high-capacity transmission pipelines that are usually 8 to 48 inches in diameter. Before the crude oil leaves the production field, it is processed to remove excess water, gases, and sediments as necessary to meet the quality specifications of transmission pipelines and the refineries they access.

Most of the estimated 55,000 miles of crude oil transmission pipeline in the United States are interconnected to form a national network that links oil production regions, storage hubs, and refineries.[2] This extensive network accounts for more than 90 percent of the ton-mileage of crude oil transported within the United States.[3]

Transmission pipelines are critical in providing refineries with a steady supply of feedstock consisting of various types of crude oil. About 140 refineries operate nationwide. Some are vast complexes that can process more than 500,000 barrels of crude oil per day, while others serve relatively small and specialized markets and process less than 50,000 barrels per day.[4]

About 40 percent of U.S. refining capacity is located along the Gulf Coast, and the next largest center is in the Upper Midwest. Originally, the Gulf Coast refineries were supplied by domestic sources, primarily from Texas and Louisiana and from shallow waters in the Gulf of Mexico. As domestic production declined in the 1970s, the Gulf Coast refineries increasingly sourced their crude oil from Mexico, Venezuela, and the Middle East. Because the imports tended to be denser and higher in sulfur, refiners invested in facilities capable of processing such feedstock. In recent years, increased production from Canada, deep Gulf waters, and domestic shale fields has replaced waterborne imports. These supply shifts have had significant implications for the transmission pipelines that once moved crude oil from Gulf Coast ports to inland refineries as far north as Illinois and Ohio. Many of these systems have had their flow directions reversed and are now being used to transport Canadian crude oil to the Gulf Coast

[1] October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/Miesner102312.pdf).

[2] The Pipeline and Hazardous Materials Safety Administration (PHMSA) has estimated that the crude oil transmission pipeline network extended for 55,330 miles as of 2011.

[3] "Ton-mile" is a measure of the weight of a substance carried multiplied by the distance over which it is carried.

[4] One U.S. barrel of crude oil contains 42 gallons.

refineries. The transition is under way, with major investments to add more north-to-south capacity by reversing more lines and building new ones.
For many decades, U.S. crude oil produced in the northern Rocky Mountains and Dakotas, as well as that produced in the western provinces of Canada, was transported to refining centers in Eastern Canada and the Upper Midwest. In recent years, as output from these oil-producing regions has grown significantly, crude oil supplies have exceeded refining capacity and are being transported south, where they are displacing crude oil traditionally sourced from Mexico, South America, and the Gulf of Mexico.

Both the East and West Coasts have remained largely independent markets for crude oil supplies. The eastern states have little oil production and no significant crude oil transmission pipelines. While the recent development of shale resources in New York and Pennsylvania is adding production capacity, truck and rail remain the dominant regional modes of crude oil transportation. The main East Coast refining centers in northern New Jersey, Philadelphia, and coastal Virginia receive most of their supplies from tanker vessels. In comparison, California has an extensive network of crude oil transmission pipelines because of significant in-state oil production. These pipeline systems, some of which consist of heated lines to move the native viscous crude oils, do not connect to pipeline systems in other states. Refineries in Washington State receive crude oil by tanker and from Western Canada by pipeline.

PIPELINE SYSTEM COMPONENTS

The individual pipeline systems that make up the U.S. crude oil transmission network vary in specific design features and components. Nevertheless, the systems have many common elements.

Line Pipe

Pipelines are made of sections of line pipe that are welded together and generally buried 3 or more feet below grade. Virtually all line pipe is made of mild carbon steel that is coated externally but not internally. Pipe sections are typically 40 feet long, manufactured with longitudinally welded seams and joined by circumferential girth welds during installation. Pipe wall thickness depends on many factors, including planned capacity and operating pressure. Most line pipe in crude oil transmission systems is operated at pressures between 400 and 1,400 pounds per square inch, is 20 or more inches in diameter, and has a nominal wall thickness ranging from 0.2 to 0.75 inches. Federal regulations in the United States require that pipeline operating pressures and other forces not generate stresses that exceed 72 percent of the specified minimum yield strength (SMYS) of the pipe, and therefore a higher operating pressure requires thicker pipe or pipe with higher yield strength.[5] Depending on pipeline design and routing factors, thicker-walled pipe may also be used where the pipeline crosses a body of water or in areas that are densely populated, environmentally sensitive, or prone to additional external forces such as seismic activity.

---

[5] Federal regulations concerning SMYS are contained in 49 CFR §195.406. The federal hazardous liquid pipeline safety regulations, as administered by PHMSA, are outlined in Box B-1, Appendix B. Some pipelines operate at 80 percent of SMYS with permission of PHMSA.

Inlet Stations and Tank Farms

Transmission pipelines originate at one or more inlet stations, or terminals, where custody of the shipment is transferred from the owner to the pipeline operator. Accordingly, inlet stations are access points for truck tankers, railroad tank cars, and tanker vessels as well as other pipelines, including gathering lines connecting production areas. Along with pumping stations, sampling and metering facilities are located at inlets to ensure that the crude oils injected into the pipeline meet the quality control requirements of the pipeline operator and intended recipients. Metering instruments usually include densitometers and may include viscometers, which are used to measure density and viscosity, respectively.

Tanks at inlet stations are used to consolidate shipments into batches sized for main-line movement, blend crude oils to meet quality specifications, and schedule shipments according to the needs of refiners. Tanks can vary in capacity from tens of thousands to hundreds of thousands of barrels.[6] All are made of steel and are unpressurized. They are usually designed with floating roofs that rise and fall with the liquid level to limit hydrocarbon loss from vaporization and minimize emissions of volatile organic compounds. Tanks usually have lined floors and are inspected and cleaned periodically to remove any water and sediment settling to the floor.

Pump Stations

To maintain desired flow rates, booster pumps are positioned at points along the pipeline at intervals of 20 to 100 miles depending on many factors, including topography, line configuration, pipe diameter, operating pressure, and the properties of the fluids being transported. Pump stations are often automated and are equipped with sensors, programmable logic controllers, switches, alarms, and other instrumentation allowing the continuous monitoring and control of the pipeline as well as its orderly shutdown if an alarm condition occurs or if established operating parameters are violated.

Valves

Shutoff valves are strategically located at pump stations, certain road and water crossings, and other points to facilitate the starting and stopping of flow and to minimize the impact of leaks. These valves, many of which can be controlled remotely, ensure that portions of the line can be isolated in the event of a leak or the need for repair or maintenance. In addition, check valves that prevent backflows may be located at elevation changes and other intermediate points. The opening and closing of valves, along with pumping station operations, are sequenced to prevent flow reversals and problems associated with over- and underpressurization. Bypass lines, safety valves (e.g., pressure and thermal relief), and surge tanks may be sited at stations to relieve pressure.

Intermediate and Terminal Facilities

Depending on the scope of operations, a transmission pipeline system may have intermediate points, in addition to terminal facilities, that connect to other pipelines, other modes of transport,

[6] Larger underground caverns are used for storage at some pipeline terminals.

and refineries. These stations usually contain tanks and crude oil sampling and metering facilities. Smaller "breakout" tanks at intermediate points may also be used to support maintenance and emergency activities; for example, to relieve pressure or to allow for temporary draining of a pipeline segment.

OPERATIONS AND CONTROL

Batch Operations

A transmission pipeline will rarely carry a single type of crude oil. At any given time, a large pipeline will usually be transporting dozens of shipments, typically in batches of at least 50,000 barrels and covering a variety of crude oil grades. Sometimes the batches are physically separated by plugs known as pigs, but most of the time they are not. To reduce undesirable mixing at interfaces, the batches are separated and sequenced according to characteristics such as density, viscosity, and sulfur content. Accordingly, batches are scheduled to permit the proper lineup of crude oils being moved into and out of storage tanks. Maintaining batch separation requires that operators closely monitor the flow characteristics of the pipeline, since reductions in flow velocity and loss of flow turbulence can lead to undesirable intermixing of batches.

Flow Regime

Most shipments flow through the pipeline at 1.5 to 3 meters per second (3 to 6 miles per hour), which equates to a delivery rate of 500,000 to 1,000,000 barrels of crude oil per day in a 36-inch transmission pipeline.[7] Flow conditions in the pipeline will remain turbulent within this range of flow velocities.[8] Pipeline operators strive to maintain turbulent flow, characterized by chaotic motion and the formation of eddies, to reduce intermixing of batches and to keep impurities such as water and sediment suspended in the crude oil stream. Choosing a desired flow regime requires the balancing of many technical and economic factors. Increasing operating pressure will increase pipeline throughput, which is generally desired by an operator to increase revenue capacity. Higher operating pressures, however, require a larger investment in pipe materials and pumping capacity and will increase energy use and operating costs.

The characteristics of the crude oil to be shipped are important considerations in establishing the flow regime. More energy is needed to pump dense, viscous crude oils than light crude oils with lower viscosity. Some crude oils are too viscous naturally to be pumped. The normal response when a highly viscous crude oil is transported is to dilute it with lighter oil. When a diluent is too costly or unavailable, an alternative approach is to transport the crude oil in a heated pipeline. However, heating a pipeline is an expensive option and presents construction

---

[7] http://www.aopl.org/aboutPipelines/?fa=faqs.

[8] Whether a flow is turbulent or nonturbulent (i.e., laminar) depends on the diameter of the pipeline, the velocity of the flow, and the viscosity of the crude oil. These parameters can be used to calculate the Reynolds number, which defines the flow regime as laminar to turbulent. As described later in Chapter 3, the kinematic viscosity of heavy crude oils can range up to about 250 centistokes (0.00025 square meter per second) at room temperature. These oils will need to be transported at about 2 meters per second (6.5 feet per second or 4.4 miles per hour) in a pipe with a diameter of 20 inches to achieve a Reynolds number higher than 4,000, which is at the transition from laminar to turbulent flow. In a larger pipe, lower velocities are required to maintain turbulence (e.g., 1 meter per second or 2 miles per hour for a 42-inch pipe). Further consideration is given to the beneficial effects of maintaining turbulent flow in Chapter 5.

and operating challenges that preclude its common use. Where the throughput capacity of a line needs to be increased without adding pumping capacity, an operator may inject drag-reducing agents to enhance flow. These chemicals, which consist of long-chain polymers, dampen turbulence at the interface between the crude oil and the pipe wall to reduce friction and enable increased flow velocity.

Pipeline flows are usually monitored and controlled by operators from one or more central control centers, where supervisory control and data acquisition systems collect and analyze data signals from sensors and transmitters positioned at pumps, valves, tanks, and other points en route. Parameters other than flow rate, such as line pressure, pump discharge pressures, and temperatures, are also monitored for routine operational and maintenance decisions and for leak detection.

Shipment Quality Control

In the United States, the Federal Energy Regulatory Commission (FERC) oversees the tariffs that interstate pipeline operators are required to publish as common carriers. For intrastate transmission pipelines, state authorities such as the Texas Railroad Commission and the California Energy Commission function much like FERC in overseeing tariffs for in-state movements.

Pipeline tariffs define the terms and conditions for the transportation service, including the quality specifications applicable to all shipments in the pipeline. The specifications are driven by both operational and commercial considerations. Measurements to ensure adherence to the specifications are usually taken at custody transfer points. It is common for these specifications to define the maximum allowable sediment and water content, viscosity, density, vapor pressure, and temperature of the shipment. Other shipment qualities, such as levels of sulfur, acid, and trace metals, are seldom delineated in published tariffs but may be specified in private agreements. Quality specifications are designed to protect the integrity of the pipeline and the ancillary facilities, ensure that the shipped crude oil meets the specifications of the refiner, and prevent valuable throughput capacity from being consumed by transporting sediment and water.

MAINTENANCE

Each operator tailors pipeline maintenance and integrity management practices within the parameters allowed by safety regulations and according to the demands of the specific system, including its age, construction materials, location, and stream of products transported. Nevertheless, many practices are standardized. Some of the most common cleaning, inspection, and mitigation practices are described below. Regulatory requirements that govern integrity management are outlined in Appendix B.

Cleaning

Periodic cleaning of crude oil pipelines and equipment is often performed to facilitate inspection as well as to maintain operational performance. Cleaning intervals, typically measured in weeks or months, will vary depending on operating conditions and crude oil properties. A variety of tools are used for cleaning the pipe and monitoring interior condition. Mechanical pigs equipped with scrapers and brushes remove debris from the inner wall. The scraped deposits and scale are transported to clean-out traps. The scrapings may be tested for contaminants and corrosion by-products.

Inspection and Monitoring

A regular inspection regime that assesses the condition of rights-of-way, pipes, pumps, valves, tanks, and other components is important to maintaining pipeline operational integrity and preventing unplanned shutdowns. Rights-of-way are routinely monitored by aerial patrols looking for threatening activities and encroachments and by field inspectors conducting detailed surveillance of line and equipment conditions. While visual inspection of buried pipe is not possible, pipes exposed for repair are usually inspected for evidence of mechanical damage or signs of degradation that may be indicative of problems elsewhere on the line.

From time to time, instrumented, or "smart," pigs are run through the line to detect anomalies. The three primary instruments are geometry, metal loss, and crack tools. Geometry tools are normally equipped with mechanical arms that survey the pipe wall to detect dents and other geometry changes. Metal loss tools use either magnetic or ultrasonic technology. Crack tools are designed to detect cracks in the pipe body, especially those that are longitudinally oriented. The frequency of instrumented pig runs is determined by the risk management program of the operator, as influenced by government regulation. Some pipeline sections, mostly in older systems, are not configured to accept some instrumented pigs.

Other techniques for monitoring conditions inside the pipe include the use of corrosion coupons and electrical resistance probes. Coupons are steel samples inserted into the pipeline and periodically removed for examination. Because the coupons are weighed before and after the exposure, the amount of corrosion can be determined by weight loss. Electrical resistance probes inserted into the pipe provide information on the corrosivity of the stream. External corrosion is monitored primarily through the use of pipe-to-soil potential surveys, whereby the voltage is measured with respect to a reference electrode to determine whether adequate cathodic protection levels are present along the length of the pipeline. Techniques are also used to measure the voltage gradients in the soil above a protected pipeline to determine the size and location of coating defects. Coupons buried in the soil can supplement this external corrosion monitoring. In addition, coatings are inspected whenever portions of the pipeline are uncovered.

Corrosion Mitigation Practices

It is standard practice for buried transmission pipelines to be coated externally to provide a physical barrier between the steel and the surrounding corrosive environment. Desired coating characteristics include low permeability to water and salts, strong adhesion to steel, and good abrasion resistance (Beavers and Thompson 2006). The coating also needs to be durable and resist chemical and thermal degradation at pipeline operating temperatures.

Pipeline coatings have improved over the past several decades. Along with cold and hot applied tapes, field-applied coatings made from coal tar, asphalt, and grease were the dominant systems used through the 1950s (Michael Baker Jr., Inc. 2008; Beavers and Thompson 2006). Because of nonoptimal conditions for field applications, early coatings often had poor adhesion characteristics, with pinholes and other imperfections. Some also exhibited degradation of the polymers. After time in service, the coatings tended to become porous or to detach from the pipe surface.

During the 1960s and 1970s, fusion bonded epoxy (FBE) coatings were introduced. Unlike other coatings, FBE coatings are formed by heating a powder on the surface of the metal. The components of the powder melt and flow to initiate a cross-linking process. These heat-cured coatings exhibit good mechanical and physical properties, including adhesive strength and resistance to degradation, and they are widely used today.

Even a well-coated pipe may have imperfections and develop small holes in the coating that can expose the pipe to corrosion attack. To counter this effect, pipelines are fitted with cathodic protection systems. In some systems, the electrochemical potential of the pipe is reduced by galvanically coupling to sacrificial anodes typically made of magnesium, aluminum, or zinc alloys that will preferentially corrode instead of the pipe. Other systems employ an impressed current applied to the pipeline with the use of a power supply to lower the pipeline potential. The cathodic protection system is designed to supply enough current to a pipe to prevent external corrosion at defects or holes that form in the coating where the external environment can come in contact with the steel surface. Defects in coatings are especially problematic when the disbonded coating shields distribution of the cathodic current to the defect site. This shielding is most often associated with the impermeable tapes and shrink sleeves used on some older pipelines. An advantage of modern FBE systems is that they are permeable to ionic flow and thus do not shield the exposed sites from cathodic protection.[9]

Preventing the internal corrosion of pipes starts with basic quality control and operational procedures that limit the entry and accumulation of water and other contaminants. As noted above, transmission pipelines are typically constructed of steel with no internal coatings, so the transported product is in contact with the steel. While oil is not corrosive, even small amounts of contaminants such as water and salts in the oil can be corrosive if they are allowed to accumulate on the steel surface. Certain gases dissolved in the product stream, especially oxygen, hydrogen sulfide, and carbon dioxide, can also increase the rate of corrosion. Actions to mitigate internal corrosion include controlling ingress of air at pumps and other entry points, limiting water and sediment content, and chemical treatment of the crude oil stream.

The chemicals injected into the crude oil stream usually consist of a mixture of additives that inhibit corrosion by various means. The most common mixtures contain surfactant chemicals that adsorb onto the steel surface and provide a barrier between the corrosive water and pipe steel. Many surfactants confer additional benefits by reducing the surface tension at the oil–water interface, which keeps the water entrained in the flow rather than depositing on the pipe wall. Chemical additives may also have properties that repel the water from the pipe wall, neutralize acids, and act as biocides to help inhibit microbiologically influenced corrosion.
The rates of flow in transmission pipelines are normally sufficient to prevent the deposition of contaminants and to sweep away deposits that settle to the pipe bottom. Areas of low flow, such as steep angles of elevation and sections of isolated piping (called dead legs), are vulnerable to water and sediment accumulation and subsequent internal corrosion. Because the hydrodynamic and chemical processes of water and sediment accumulation are well understood, models for

[9] Inspections performed on gas gathering lines equipped with an early generation FBE coating (from the mid-1970s) revealed that less than 0.2 percent of pipeline sections exhibited blistering of the coating despite some operating in temperatures as high as 76°C (170°F). Removal of the blistered coating revealed no underlying corrosion because of the permeability of FBE to cathodic fields (Boerschel 2010; Batallas and Singh 2008).

analysis are available to guide pipeline construction and operating parameters to decrease the tendency for accumulations and to identify areas of greatest vulnerability to corrosion.

Additional details on the mechanisms of pipeline damage and factors that contribute to them are discussed in Chapter 5.

SUMMARY

The crude oil transmission network in the United States consists of an interconnected set of pipeline systems. Shipments traveling through the network often move from one pipeline system to another, sometimes being stored temporarily in holding tanks at terminals. Most operators of transmission systems are common carriers who do not own the crude oil they transport but provide transportation services for a fee. Few major transmission pipelines are dedicated to transporting specific grades or varieties of crude oil. They usually move multiple batches of crude oil, which are often provided by different shippers and include a range of chemical and physical properties. Crude oil shipments are treated to meet the quality requirements of the pipeline operator as well as the content and quality demands of the refinery customer.

Pipeline systems traverse different terrains and can vary in specific design features, components, and configurations. These differences require that each operator tailor operating and maintenance strategies to fit the circumstances of its systems in accordance with regulatory requirements. Nevertheless, the systems tend to share many of the same basic components and follow similar operating and maintenance procedures. Together, regulatory and industry standards, system connectivity, and economic demands compel both a commonality of practice and a shared capability of handling different crude oils.

REFERENCES

Argonne National Laboratory. 2008. *Overview of the Design, Construction, and Operation of Interstate Liquid Petroleum Pipelines*. Report ANL/EVS/TM/08-1. http://www.ipd.anl.gov/anlpubs/2008/01/60928.pdf.

Batallas, M., and P. Singh. 2008. Evaluation of Anticorrosion Coatings for High Temperature Service. Paper 08039. Presented at 17th International Corrosion Conference, National Association of Corrosion Engineers International, Houston, Tex.

Beavers, J. A., and N. G. Thompson. 2006. External Corrosion of Oil and Natural Gas Pipelines. *ASM Handbook, Vol. 13C, Corrosion: Environments and Industries*, pp. 1015–1025. http://www.asminternational.org/content/ASM/StoreFiles/ACFAB96.pdf.

Boerschel, V. 2010. New Developments of Mid-TG-FBE Powder Coatings to Meet the Requirements of Pipe Coaters and Pipeline Owners. Paper 10012. Presented at 19th International Corrosion Conference, National Association of Corrosion Engineers International, Houston, Tex.

Michael Baker Jr., Inc. 2008. *Pipeline Corrosion: Final Report*. U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, Washington, D.C., Nov. http://primis.phmsa.dot.gov/gasimp/docs/FinalReport_PipelineCorrosion.pdf.

National Petroleum Council. 2011. *Crude Oil Infrastructure*. Paper 1-7. Oil Infrastructure Subgroup of the Resource and Supply Task Group, Sept. 15. http://www.npc.org/Prudent_Development-Topic_Papers/1-7_Crude_Oil_Infrastructure_Paper.pdf.

Rabinow, R. A. 2004. *The Liquid Pipeline Industry in the United States: Where It's Been, Where It's Going*. Association of Oil Pipe Lines, Washington, D.C., April.

3

Bitumen Properties, Production, and Transportation by Pipeline

This chapter describes the chemical composition and physical properties of bitumen, the methods used to produce it, and the properties of the bitumen shipments that are diluted for pipeline transportation to the United States.

BITUMEN COMPOSITION AND PROPERTIES

Like all forms of petroleum, bitumen is a by-product of decomposed organic materials rich in hydrocarbons. According to the World Energy Council, bitumen deposits exist in about 20 countries, but the largest are in Canada, Kazakhstan, and Russia (WEC 2010, 123–150). Because only the Canadian bitumen is diluted for transportation by pipeline to the United States, it is the subject of the description in this chapter.[1]

Canadian bitumen deposits are concentrated in the Western Canadian Sedimentary Basin (WCSB), and particularly in the province of Alberta. Three regions in the WCSB have large reserves: the Athabasca, Peace River, and Cold Lake regions (Strausz and Lown 2003, 21). According to the government of Alberta, about two-thirds of the world reserves of recoverable bitumen are contained in the three regions, which total some 140,000 square kilometers (55,000 square miles) (ERCB 2012a). In some locations in Alberta, surface deposits are easy to spot, since the black bitumen is impregnated in sandstone along the sides of lakes and rivers. Most of the bitumen is not visible because it is deposited below the surface.

The bitumen-impregnated sands in the WCSB are referred to as bituminous sands, oil sands, and tar sands (Strausz and Lown 2003, 29). Canadians use the term oil sands, which is also used in this report. The typical composition of the WCSB oil sands is 85 percent sand and clay fines,[2] 10 percent bitumen, and 5 percent water by weight.[3] Oil sands also contain salts, trace gases, and small amounts of nonpetroleum organic matter.[4] These components exist together in a specific microstructure with a film of water that surrounds each sand and clay particle, and the bitumen surrounds the film, as shown in Figure 3-1. When freed from this microstructure, bitumen has a typical elemental composition of 81 to 84 percent carbon; 9 to 11 percent hydrogen; 1 to 2 percent oxygen, nitrogen, and other elements; and 4 to 6 percent sulfur, most of which is bound in the bitumen in stable (e.g., heterocyclic rings) hydrocarbon structures (Dettman 2012; Strausz et al. 2011; Gogoi and Bezbaruah 2002; Strausz and Lown 2003).

---

[1] Canada contains the vast majority of the natural bitumen in North America. According to the U.S. Geological Survey, bitumen deposits exist in the United States in several states, mainly in Utah, California, and Alabama. While commercial mining operations are being planned in Utah, many technical and economic challenges remain to exploit this resource (USGS 2006).
[2] The solid particles consist of sand grain minerals, mostly of quartz but also feldspar, mica, and chert. The solid particles also consist of clay minerals, mostly kaolinite and illites (Strausz and Lown 2003, 31–32).
[3] Up to 18 percent of the ore can be made up of bitumen (Strausz and Lown 2003, 62).
[4] The organic matter consists of humin, humic acids, fulvic acids, and chemiabsorbed aliphatic carboxylic acids (Strausz and Lown 2003, 29–32).

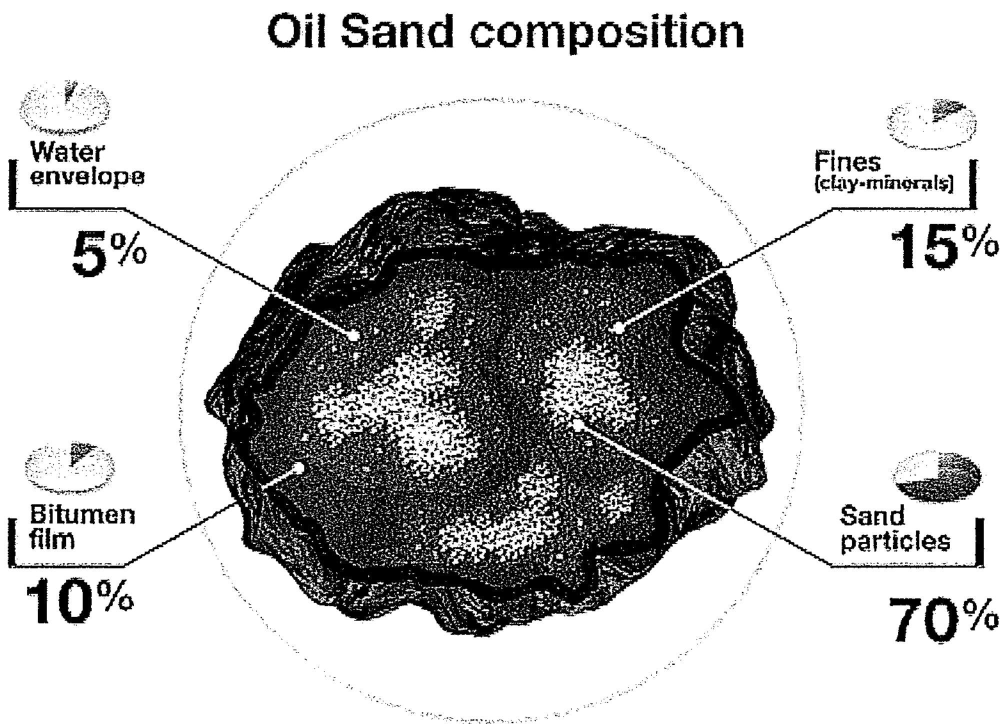

FIGURE 3-1 Composition of oil sands.

Hydrocarbon molecules account for 92 to 95 percent of the weight of bitumen.[5] These molecules range from light alkanes, such as ethane, to long-chain compounds with relatively high molecular weights and boiling points. The latter molecules are more common in bitumen than in the lighter, more paraffinic crude oils that have undergone less microbial degradation.[6] Bitumen contains relatively high concentrations of asphaltenes, which account for 14 to 17 percent of the total weight of the material (Strausz and Lown 2003, 95; Rahimi and Gentzis 2006, 151). Trace elements, such as vanadium and nickel, usually reside in the asphaltenes along with sulfur, nitrogen, and oxygen (Strausz and Lown 2003, 93–99, 495–498). The nitrogen in the bitumen is bonded with carbon in pyridinic structures, including quinolines and acridines (Rahimi and Gentzis 2006). The asphaltenes, as well as other nonparaffinic compounds such as naphthenes, give bitumen its high density and high viscosity (Strausz and Lown 2003, 99).

Bitumen is usually distinguished from other forms of petroleum on the basis of physical properties that derive in part from its relatively high asphaltene content. The U.S. Geological Survey (USGS) has used the following definition to distinguish bitumen from other heavy crude oils:

---

[5] The ratio of hydrogen to carbon atoms is about 1.5 in bitumen, compared with 2.0 for very light oils (Strausz and Lown 2003, 95–96).

[6] Bitumen has undergone more biodegradation than have other petroleum oils. Because straight-chain paraffinic hydrocarbons are more readily metabolized by microorganisms, these hydrocarbons are depleted in bitumen (Strausz and Lown 2003, 90).

> Natural bitumen is defined as petroleum with a gas-free viscosity greater than 10,000 centipoises (cp) at original reservoir temperature. Petroleum with a gas-free viscosity between 10,000 and 100 cp is generally termed heavy crude oil. In the absence of viscosity data, oil with API gravity less than 10 degrees is generally considered natural bitumen, whereas oil with API gravity ranging from 10 degrees API to about 20 degrees API is considered heavy crude oil. The term extra-heavy crude oil is used for oil with a viscosity less than 10,000 cp but with API gravity less than 10 degrees. (USGS 2006)

The American Petroleum Institute (API) gravity scale referenced by USGS is an inverse measure of the density of a liquid relative to that of water at room temperature. A liquid with API gravity greater than 10 degrees will float on water; if the API gravity is lower than 10 degrees, it will sink.[7] Canadian bitumen (undiluted) typically has an API gravity between 7 and 13 degrees, whereas most heavy crude oils have values that are 5 to 15 degrees higher (Strausz and Lown 2003, 100). The viscosity of bitumen is also high compared with that of other crude oils across a range of temperatures. Figure 3-2 compares the effects of temperature on viscosity [in centipoise units (cp)] for bitumen derived from two WCSB reservoirs (Cold Lake and Athabasca), a Canadian heavy crude (Lloydminster), and typical light crude oils.[8] At most pipeline operating temperatures [0°C to 40°C (32°F to 100°F)], the lighter crude oils will behave as liquids, while the bitumen will remain in a semisolid state, having viscosities comparable with that of peanut butter. Although they are less viscous than bitumen, the heaviest conventionally drilled Canadian crude oils have relatively high viscosities as well.[9] Several Canadian crude oils, including the Lloydminster crude oils shown in Figure 3-2, are routinely diluted with lighter oils to improve their flow in transmission pipelines.[10]

BITUMEN PRODUCTION

The WCSB has long been a major oil-producing region of North America. Oil exploration commenced in the early 20th century, and by the 1960s hundreds of millions of barrels of Western Canadian crude oil were being exported each year through pipelines to the United States. Nearly all of this oil was produced with conventional drilling and well technology. By the 1990s, Western Canadian exports of conventionally produced oil were declining just as new technologies were being introduced to recover the vast deposits of bitumen contained in oil sands.

[7] API gravity values are referred to as "degrees." Most crude oils have API gravities in the range of 20 to 40 degrees, but some range 10 degrees higher or lower.
[8] Centipoise is a measure of resistance to shear flow, or the dynamic viscosity of a fluid. A more common measure of resistance to flow by crude oils is the centistoke (cSt), which is the ratio of dynamic viscosity to fluid density, also known as kinematic viscosity. At room temperature, the kinematic viscosity of bitumen will exceed 100,000 cSt, compared with about 25 cSt for a medium-density crude oil. Kinematic viscosity is referenced more often in this report.
[9] This Canadian heavy crude oil is usually diluted with lighter oils for pipeline transportation.
[10] Lloydminster heavy crude oils have API gravities of 12 to 23 degrees (Strausz and Lown 2003, 26).

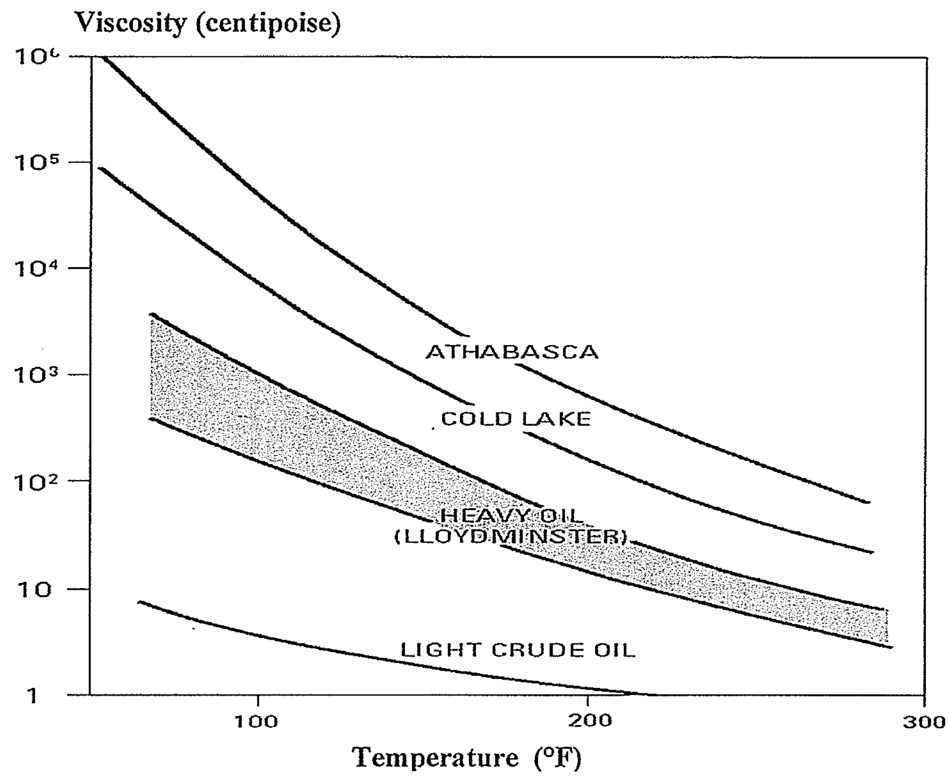

FIGURE 3-2 Response of crude oil viscosity to changes in temperature (Raicar and Procter 1984; WEC 2010, 126).

While natural bitumen had long been used as sealing material, Canadian entrepreneurs started mining deposits for refinery feed during the early 20th century. However, separating the bitumen from the mined ore required significant amounts of heated water, which made recovery expensive compared with the lighter crude oils that were less costly to drill elsewhere in Canada and the United States. Commercial ventures to mine bitumen began in the 1920s, but it took another 40 years of declining North American crude oil reserves, increasing consumer demand for gasoline and other refined petroleum, and advances in extraction and processing technologies to transform the mined bitumen into a commercially viable refinery feedstock.[11]

During the 1990s, thermally assisted in situ recovery methods were introduced in the WCSB to exploit the large reserves of bitumen located too deep for surface mining. After this development, the quantity of bitumen produced surpassed the quantity of conventionally produced oil from the basin. Today, bitumen accounts for more than 70 percent of the petroleum produced in Alberta, and in situ recovery methods account for nearly half of this bitumen production (ERCB 2012a).

[11] Oil Sands Discovery Centre. Facts About Alberta's Oil Sands and Its Industry. http://history.alberta.ca/oilsands/docs/facts_sheets09.pdf.

One in situ method in particular—steam-assisted gravity drainage (SAGD)—led to the recent growth in Canadian bitumen production for export to the United States. Indeed, no significant quantities of mined bitumen are diluted for pipeline transportation to the United States, the main market for bitumen recovered by using the SAGD process.[12]

Bitumen Mining and Upgrading to Synthetic Crude Oil

About 20 percent of the bitumen deposits in the WCSB are less than 60 meters (200 feet) deep and can be recovered by surface mining. Mining operations use diesel-powered shovels to excavate the ore, which is transported by truck to field facilities containing crushers. The crushed ore is mixed, or washed, with hot water to create a slurry that is piped a short distance, where it is agitated and filtered in separation vessels. The hot water heats and releases the water that surrounds the sand and clay particles. The agitation causes air bubbles to attach to bitumen droplets, which float in a froth to the top of the vessel. The froth is then deaerated with steam and diluted with a hydrocarbon solvent such as naphtha. The solvent coalesces and causes settlement of emulsified water and mineral solids. The suspended bitumen is then separated with a centrifuge and skimmer.

The extraction process for mined bitumen yields a product that typically contains 0.5 percent solids and 1 to 2 percent water by volume. This solid and water content is generally too high to be accepted by transmission pipelines. As a consequence, mined bitumen is nearly always upgraded, usually at nearby field plants, into synthetic crude oil. The field plants consist of refinery-type cokers that crack the bitumen into lighter products that are then processed in hydrotreating units to remove sulfur and nitrogen.[13] The processed streams are then mixed to produce a low-viscosity, low-sulfur synthetic crude oil that can be transported by transmission pipeline to refineries in Canada and the United States. The synthetic crude oils are also blended with other heavy Canadian crude oils, including in situ–produced bitumen, for pipeline transportation to the United States.

Nearly all of the bitumen mined in the WCSB is upgraded to synthetic crude oil.[14] This situation is subject to change as alternative methods are introduced to yield mined bitumen with reduced viscosity and water and sediment content comparable with that of the bitumen produced in situ and transported in diluted form through transmission pipelines. One alternative is to deasphalt the mined bitumen partially to produce synthetic crude oil that retains some of the heavier hydrocarbon fraction by substituting a paraffinic solvent for the aromatic-rich naphtha solvent traditionally used during removal of water and solids (Rahimi et al. 1998). Composed largely of pentanes and hexanes, a paraffinic solvent is more effective than naphtha in promoting aggregation and settlement of asphaltenes and suspended water and solids. Removal of asphaltenes through paraffinic treatment yields a processed bitumen that is less viscous and has lower levels of water and solids than mined bitumen that is processed with a traditional naphtha solvent.

---

[12] The discussion focuses on surface mining and SAGD, which are the most common bitumen recovery methods. Other methods not discussed include cyclic steam stimulation, toe-to-heel air injection, vapor-assisted petroleum extraction, and cold heavy oil production with sand. More information on recovery methods can be found at http://www.oilsands.alberta.ca/.

[13] According to the Alberta Energy Ministry, the five upgraders operating in Alberta in 2011 had the capacity to process approximately 1.3 million barrels of bitumen per day (ERCB 2013).

[14] According to the Alberta Energy Ministry, in 2011 about 57 percent of oil sands bitumen production was upgraded to synthetic crude oil in Alberta. Most upgraders produce synthetic crude oil, but some also produce refined products such as diesel (ERCB 2013).

Mined bitumen processed with paraffinic solvent can be transported by transmission pipeline, usually by retaining some of the solvent as diluent.[15] Mined bitumen treated in this manner is being piped several hundred miles from oil sands production regions to large, centrally based upgraders elsewhere in Alberta, where it is processed into synthetic crude oil. The mined bitumen, however, is not transported through pipelines to the United States (except when upgraded to synthetic crude oil) because paraffinic solvents are too expensive to use as diluent for long-distance transportation. Instead, the solvent is recovered at the Canadian upgraders and piped back to bitumen production fields for reuse as a solvent.

In Situ Recovery

Because most Canadian bitumen is located deep underground, it can only be recovered in place. Although reaching the deposits is not difficult,[16] the challenge in recovering them is in separating and thinning the bitumen for pumping to the surface. A recovery method that is now common involves the injection of pressurized steam into the deposit. The steam thins the bitumen and separates it from the sand while the pressure helps to push the bitumen up the well.

A number of thermally assisted recovery methods are used in the WCSB. The two main methods are cyclic steam stimulation (CSS) and SAGD. CSS involves injecting steam into the bitumen deposit and letting it soak for several weeks. This process causes the bitumen to separate from the sand and become sufficiently fluid for pumping. Over the past decade, SAGD has surpassed CSS as the preferred thermal recovery method because a higher proportion of the bitumen is recovered. SAGD involves drilling two horizontal wells, one located a few feet above the other as shown in Figure 3-3. Steam is injected into the upper well, which heats the bitumen and causes it and steam condensate to drain into the lower well for pumping to the surface. At the surface, condensed water is separated from the recovered bitumen and recycled to produce steam for subsequent applications.

The high recovery ratio of SAGD is an important reason for the growth in Canadian bitumen production. SAGD now accounts for about half the bitumen recovered from the WCSB.[17] Compared with mining, SAGD has the advantage of eliminating the need to wash the ore with hot water because the bitumen is separated from the sand and clay underground. After further treatment (e.g., standard degassing, dewatering, and desalting), the recovered bitumen contains much lower levels of water and sediments (generally less than 0.5 percent by volume) than mined bitumen, and it is sufficiently stable for acceptance by long-distance pipelines. Whereas nearly all mined bitumen is upgraded into synthetic crude oil in Alberta, less than 10 percent of the SAGD-derived bitumen is processed into synthetic crude oil (NEB 2009). Most SAGD-derived bitumen is diluted with lighter oils for transportation by pipeline to U.S. refineries.

---

[15] While asphaltene concentrations have significant implications for bitumen viscosity, the removal of all asphaltenes would not reduce viscosity enough for undiluted bitumen to meet pipeline specifications (Rahimi and Gentzis 2006).

[16] The exploited deposits are generally less than 750 meters (2,500 feet) underground.

[17] In 2011, about 1.7 million barrels per day of bitumen were produced, with surface mining accounting for 51 percent and in situ processes accounting for 49 percent of the production (ERCB 2013).

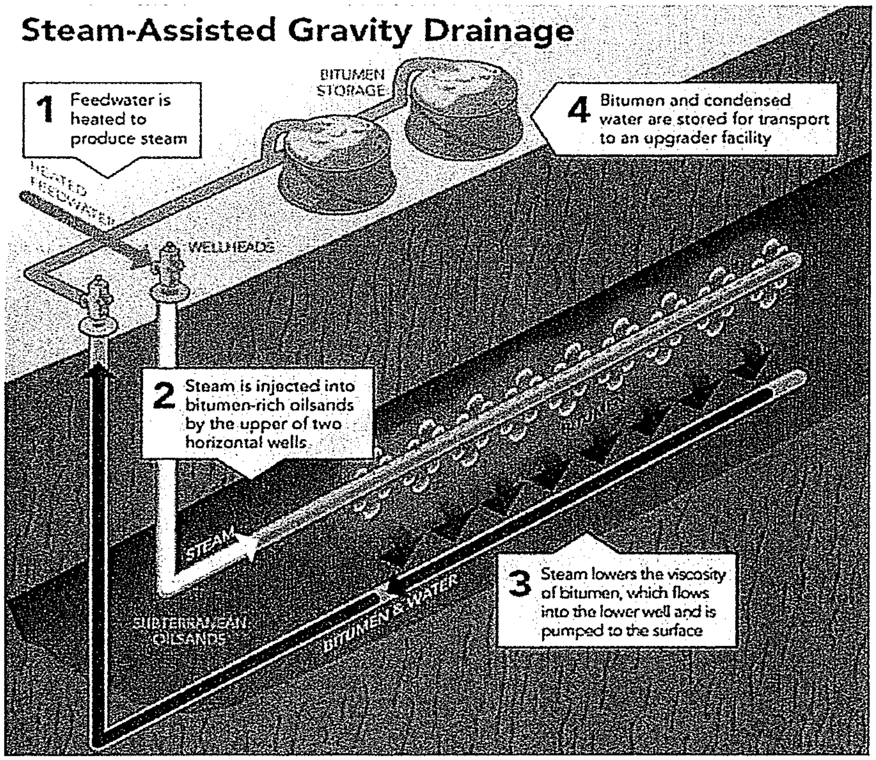

FIGURE 3-3 Bitumen recovered using SAGD (ERCB 2012b).

PIPELINE TRANSPORTATION OF DILUTED BITUMEN

According to the U.S. Department of Energy, imports of Canadian diluted bitumen and other crude oils have grown by more than one-third since 2000.[18] Partially as a result of Canadian supplies as well as newly exploited domestic oil shale, crude oil imports from other regions of the world are declining. In particular, the Canadian feedstock has supplanted heavy crude oils once imported in large volume from Venezuela and Mexico (Figure 3-4). While more than two-thirds of the Canadian crude oil is refined in the Midwest, refinery demand for this feedstock has been growing in other regions of the country, particularly at Gulf Coast refineries that are equipped to process heavy feed.

U.S. Pipelines Transporting Diluted Bitumen

Figure 3-5 shows U.S. refinery destinations for diluted bitumen and other Canadian crude oils, and Figure 3-6 shows the main pipeline corridors that access these refineries. Major export pipelines from Canada include the Enbridge Lakehead network, which serves several Great Lakes refineries; the TransCanada Keystone pipeline, which accesses the Cushing, Oklahoma, hub and refineries in southern and central Illinois; and the Kinder Morgan Express and Prairie

[18] http://www.eia.gov/countries/cab.cfm?fips=CA.

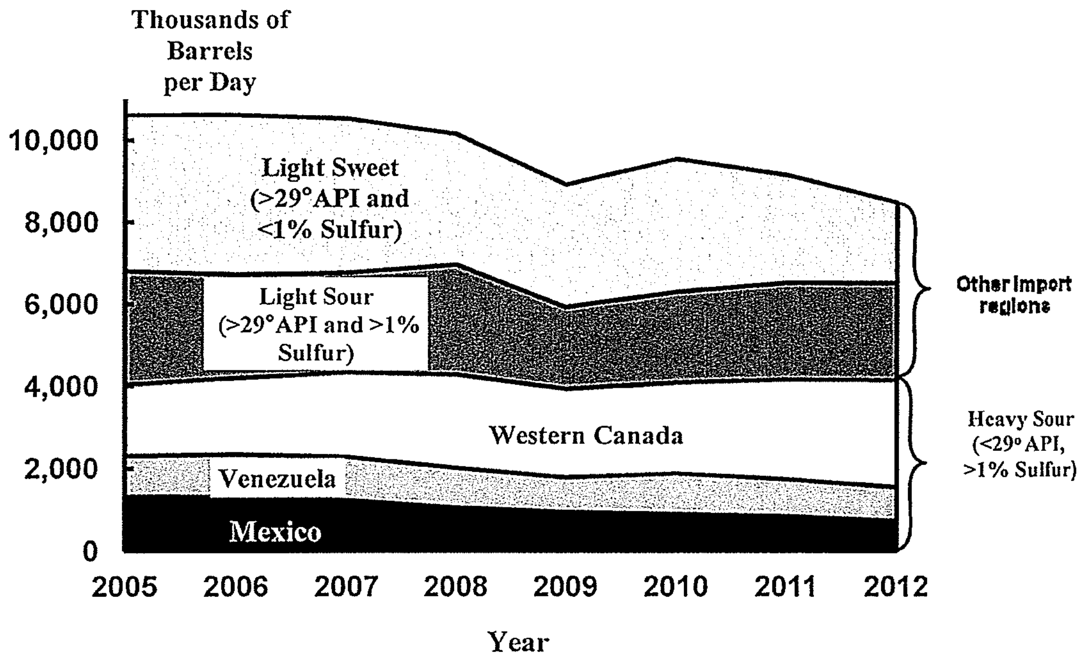

FIGURE 3-4 Annual U.S. crude oil imports by grade and origin. [Chart is derived from January 31, 2012, presentation to the committee by G. Houlton. Source data on crude oil imports were obtained from the Energy Information Administration, U.S. Department of Energy (http://www.eia.gov/countries/cab.cfm?fips=CA).]

pipelines, which transport Canadian crude oils to refineries in the Rocky Mountains and provide surplus to refineries farther east and south. These trunk lines are connected to pipelines that deliver feed to refineries as far east as Ohio and western Pennsylvania and as far south as the Texas Gulf Coast and New Mexico. Several connecting pipelines have recently undergone flow reversals, such as the 375-mile Occidental Centurion line, which now runs southwest from Cushing in the direction of El Paso, Texas; the 858-mile ExxonMobil Pegasus line, which runs south from Illinois to refineries on the Gulf Coast; and the 670-mile Enbridge Seaway line, which crosses East Texas and is expected to become fully operational during 2013.

Properties of Diluted Bitumen Shipped by Pipeline

In Canada, the National Energy Board (NEB) administers the tariffs, or terms and conditions, that govern the transportation of crude oil by transmission pipeline. For shipments entering the United States, pipeline operators must also file tariffs with the Federal Energy Regulatory Commission. As explained in Chapter 2, tariffs contain quality specifications for crude oil shipments that are intended to ensure compliance with the operational requirements of pipelines as well as possession of properties required by refiners. At custody transfer points, pipeline operators sample shipments to confirm compliance with tariff specifications.

Density and Viscosity Levels

To ensure pipeline transportability, NEB tariffs specify that the density of crude oil shipments not exceed 940 kilograms per cubic meter (kg/m^3) (about 20 degrees API gravity) and that viscosity not exceed 350 cSt[19] when measured at the posted pipeline operating temperature.[20] To meet the specifications, Canadian bitumen is diluted into either "dilbit" or "synbit." The Canadian Association of Petroleum Producers describes dilbit as a bitumen blend consisting of diluent that has a density of less than 800 kg/m^3 (45 degrees API). If it has a density greater than or equal to 800 kg/m^3, the diluent is presumed to be synthetic crude oil, and the blend is called synbit (CAPP 2013).

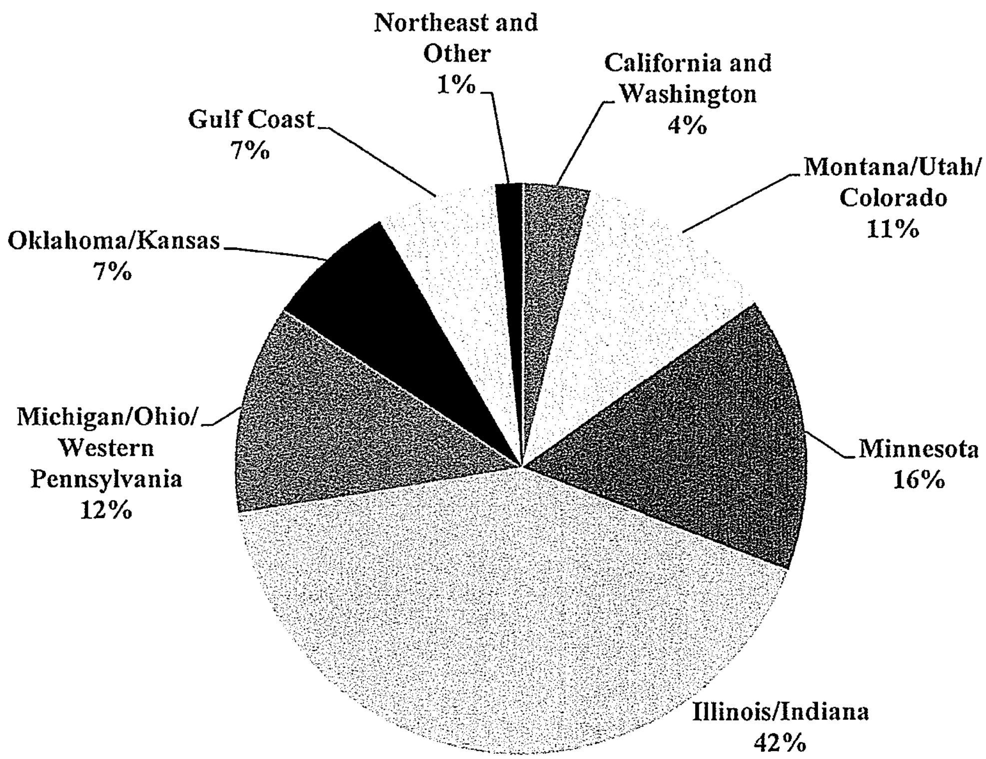

FIGURE 3-5 U.S. refinery destinations for Canadian heavy crude oil imports in 2011. [Source: National Energy Board fact sheet "Disposition of Heavy Crude Oil and Imports" (http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/dspstnfdmstccrdlndmprts-eng.html#s1).]

[19] Kinematic viscosity and the centistoke (cSt) unit of viscosity measurement have been defined earlier in this chapter.

[20] For an example, see Article 1, page 3 (Definition for Heavy Crude) of NEB Tariff Number 4, Keystone Pipeline System Petroleum Tariff (http://www.transcanada.com/docs/Key_Projects/06_NEB_Tariff_No_4_Rules_and_Regs_CL.pdf).

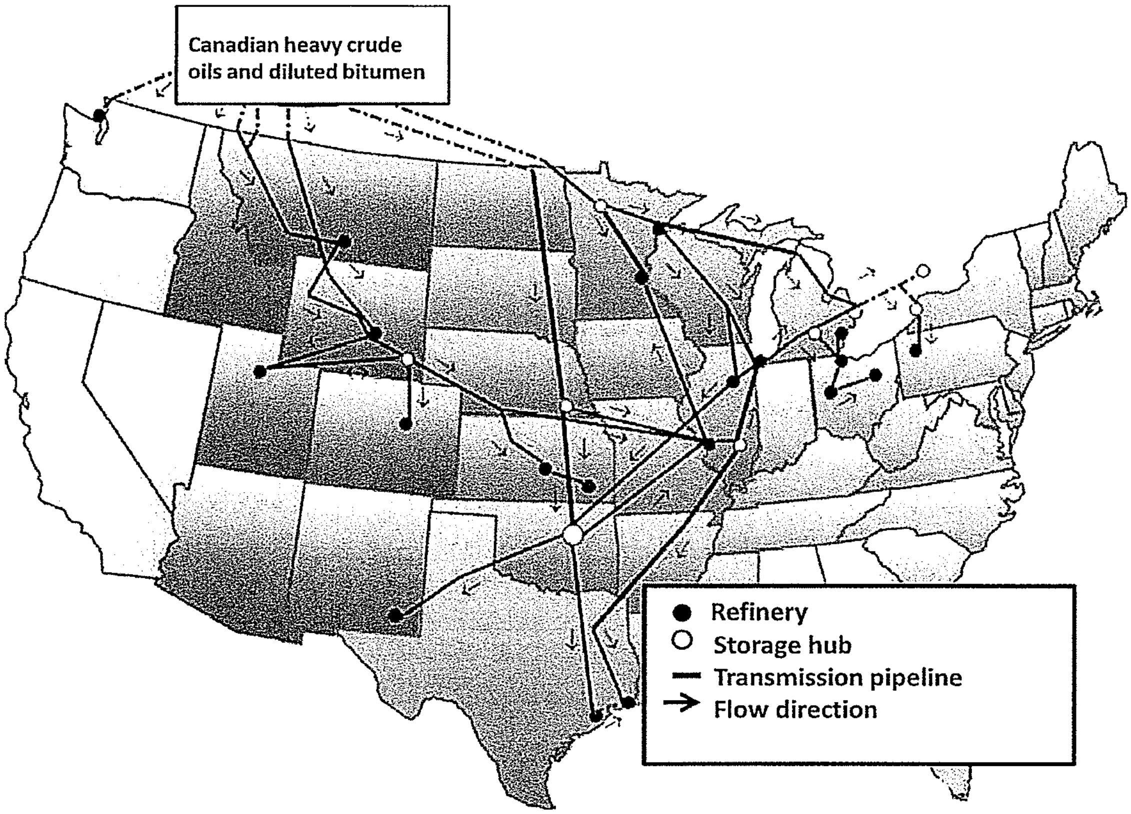

FIGURE 3-6 Main pipeline corridors moving Canadian crude oil to U.S. refineries.

In the case of dilbit, the most common diluents are naphtha-based oils, including natural gas condensate.[21] The light oils that are used have low densities (<750 kg/m^3), high API gravities (>60 degrees), and low viscosities (<1 cSt at room temperature). Compared with condensate, synthetic crude oils have higher densities (825 to 875 kg/m^3), lower API gravities (30 to 40 degrees), and higher viscosities (5 to 20 cSt). Some bitumen shipments are diluted with both condensate and synthetic crude oil to produce "dilsynbit."

Dilution and blending activity is common in the petroleum industry, as distillates and light oils are regularly mixed with heavier oils to alter shipment density and viscosity characteristics. The chemical compatibility of the oils and distillates must be considered before blending, particularly to avoid precipitation of asphaltenes. Thick deposits of these components can foul pipelines, pumps, and other equipment to create an increased need for pig cleaning to prevent flow assurance problems (Cimino et al. 1995; Saniere et al. 2004; Leontaritis and Mansoori 1988). Dilution with distillates containing high concentrations of light hydrocarbons such as pentanes and hexanes can cause asphaltenes to precipitate from oils if the distillate makes up a majority of the volume of the blend (Maqbool et al. 2009). The acceptable types and ratios of distillates blended with bitumen have therefore been analyzed to ensure chemical compatibility as well as a transportable product that does not deposit asphaltenes during postproduction storage and transportation (Schermer et al. 2004).

---

[21] Condensate liquid is produced from raw natural gas when the temperature is reduced below the boiling temperature of the gas.

As discussed earlier, distillates such as naphtha are usually mixed with bitumen at the production plant to facilitate water and sediment removal. Indeed, all or most of the diluent in diluted bitumen is blended during the processing stage before delivery of shipments for transmission by pipeline. In some cases, more diluent may be added after delivery to the transmission pipeline if further dilution is necessary to meet the density and viscosity levels required for long-distance transportation.[22] Like all crude oil blending, the mixing of diluent and bitumen is designed to make the shipped product miscible, or fully mixed in all proportions. As discussed in Chapter 2, once in the pipeline, batch shipments of diluted bitumen and other heavy crude oils are sequenced to avoid contact with lighter crude oil and condensate shipments. Meters along the pipelines track the batched stream to detect any changes in shipment density and viscosity.

After blending, diluted bitumen becomes a mixture of hydrocarbons with a range of molecular weights. As in the case of other crude oils, these hydrocarbons are separated by distillation at recipient refineries. Table 3-1 compares the distilled volume of light (low-molecular-weight) hydrocarbons in three diluted bitumen crude oils and five light, medium, and heavy crude oils imported from Canada. The light hydrocarbons in all crude oils are mainly

TABLE 3-1 Percentage (by Volume) of Low-Molecular-Weight Hydrocarbons in Selected Diluted Bitumen Blends and Other Canadian Crude Oils

	Access Western Blend (Diluted Bitumen)	**Wabasca Heavy** (Diluted Bitumen)	**Borealis Heavy Blend** (Diluted Bitumen)	**Koch Alberta** (Light Crude Oil)	**Light Sour Blend** (Light Crude Oil)	**Sour High Edmonton** (Medium Crude Oil)	**Smiley–Coleville** (Heavy Crude Oil)	**Lloyd Kerrobert** (Heavy Crude Oil)
Butanes	0.72	1.93	0.38	4.50	2.43	2.43	0.54	2.04
Pentanes	8.53	1.92	4.01	2.39	3.25	2.56	4.88	6.00
Hexanes	7.06	3.00	5.75	4.54	6.13	4.59	3.95	3.96
Heptanes	4.73	3.47	4.57	5.61	7.44	5.31	2.7	2.12
Octanes	2.74	3.53	5.28	6.09	8.72	5.58	2.12	1.38
Nonanes	1.43	2.64	4.04	4.97	7.18	4.60	2.05	1.36
Decanes	0.70	1.21	1.49	2.49	3.46	2.46	1.10	0.81
Total	25.91	17.7	25.52	30.59	38.61	27.53	17.34	17.67
Mass Recovered	**Distillation Temperature °C (°F)**							
5%	38 (101)	93 (200)	64 (147)	45 (114)	69 (156)	64 (147)	62 (144)	51 (123)
10%	70 (158)	152 (307)	93 (200)	92 (198)	87 (188)	93 (200)	114 (237)	136 (276)

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Accessed March 1, 2013.

[22] Information on production processes was obtained from briefings by and interviews with bitumen producers and pipeline operators.

pentanes or heavier, with some measurable butanes and trace amounts of lighter molecules. Because of the diluent, the light fraction of diluted bitumen is comparable with that of medium and heavy crude oils and accounts for 17 to 27 percent of hydrocarbon volume.

The specific diluents used in blending are selected on the basis of many factors, including their availability in bitumen production regions. Table 3-2 shows the chemical and physical properties of the common diluent Southern Lights, a condensate produced in the United States and piped to Alberta. Because of its low viscosity, this condensate and others can be mixed with bitumen at a ratio of about 30:70 by volume.[23] Table 3-2 also shows the chemical and physical properties of a Suncor synthetic crude oil. Because it has a higher density than condensate, this and other synthetic crude oils are usually blended in even (50:50) ratios with bitumen. Illustrative blending ratios and resulting density and viscosity values for synbit and dilbit are given in Table 3-3.

TABLE 3-2 Selected Properties of Two Common Diluents

Property	Southern Lights Condensate Diluent	Suncor Synthetic Crude Oil Diluent
Density (kg/m^3)	675	861
API gravity (°)	78	33
Sulfur (weight percent)	0.03	0.17
Viscosity at 20°C (68°F) (cSt)	<0.5	6.3
Sediment (parts per million by weight)	16	0

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN) and from Enbridge website (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Both accessed March 1, 2013.

TABLE 3-3 Example Blending Ratios and Density and Viscosity Levels for Synbit and Dilbit

Blend Component	Volume Percent	Density (kg/m^3)	Viscosity [cSt at 15°C (59°F)]
Synbit			
Bitumen	51.7	1,010	760,000
Synthetic crude oil	48.3	865	5.9
Total	100	940	128
Dilbit			
Bitumen	74.6	1,010	760,000
Condensate	25.4	720	0.6
Total	100	936	350

SOURCE: Illustrative blending ratios provided by R. Segato, Suncor Energy, October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/Segato102312.pdf).

[23] These blending ratios are nominal and will vary somewhat depending on seasonal temperatures and the flow regime of individual pipeline operators.

Once they are diluted for transportation, shipments of bitumen have physical properties comparable with those of other heavy crude oil shipments, and they can be stored and transported through the same pipeline facilities in a similar manner—that is, without a need to heat the crude oil to increase fluidity. API gravities for dilbit and synbit blends are generally in the low 20 degrees (a density of about 925 kg/m^3), and viscosities generally range between 75 and 200 cSt at pipeline operating temperatures.

Table 3-4 shows average density, API gravity, and viscosity values for six common diluted bitumen blends. The values are compared with those of six other heavy Canadian crude oils that are commonly piped to the United States. In some cases, these other heavy crude oils are also blended with lighter oils. As would be expected of commercial crude oils, the 12 sampled products have viscosities that conform to requisite pipeline tariff specifications.

According to API, shipments of diluted bitumen enter transmission pipelines at the same temperatures as other Canadian crude oils, generally in the range of 4°C to 25°C (40°F to 75°F) (API 2013). Temperatures will increase as a result of friction as the crude oil flows through the pipeline and because of high ambient temperatures during summer months. Because more pumping energy is needed for viscous crude oils, the temperature will be elevated in pipeline segments downstream from pumps. The temperature gain from pumping, however, will be the same for diluted bitumen as for other crude oils with similar densities and viscosities. Increasing pumping energy to boost the flow rate will raise the temperature further, but this effect will remain the same for all crude oils with corresponding levels of density and viscosity. Within the constraints of the design and safety factors of a pipeline, an operator may elect to increase the flow rate of any crude oil type as a means of adding throughput capacity, but this is strictly an economic decision.

TABLE 3-4 Comparison of Density, API Gravity, and Viscosity of Diluted Bitumen and Other Canadian Crude Oils

	Canadian Heavy Crude Oils					
	Bow River	Fosterton	Lloydminster Blend	Lloydminster Kerrobert	Smiley–Coleville	Western Canadian Blend
Density (kg/m^3)	914	927	927	930	932	929
API gravity (°)	23	21	21	20	20	21
Viscosity at 20°C (68°F) (cSt)	100	96	145	146	144	145
Viscosity at 40°C (104°F) (cSt)	37	36	52	52	51	52
	Diluted Bitumen					
	Access Western	Cold Lake	Peace River Heavy	Christina Lake	Wabasca Heavy	Surmount Heavy (Synbit)
Density (kg/m^3)	926	928	931	923	935	936
API gravity (°)	21	21	20	22	20	19
Viscosity at 20°C (68°F) (cSt)	150	153	113	178	134	131
Viscosity at 40°C (104°F) (cSt)	53	54	44	62	49	47

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/tools/comp/crudecomparisons.php#results) and from Enbridge website (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Both websites accessed March 1, 2013.

Water and Sediment Content

Refiners dislike crude oil feed containing excess water and sediment that requires filtration and added treatment for effluent disposal. Furthermore, they do not want to pay for the transportation of these impurities in crude oil shipments. Water and sediment are also undesirable from the standpoint of pipeline operators because of the potential for internal corrosion, as discussed in Chapter 5. Canadian pipeline tariffs specify that basic sediment and water (BS&W) in crude oil shipments not exceed 0.5 percent by volume. While U.S. tariffs tend to allow higher BS&W limits (1 percent in most cases), the lower Canadian threshold becomes the constraining factor for diluted bitumen and other crude oils piped into the United States from Canada.

Data specifically on the water content of pipeline shipments are difficult to obtain (as distinguished from data on combined water and sediment volumes). Nevertheless, because the Canadian tariffs are generally more restrictive than those in the United States, it can be inferred that shipments of Canadian crude oils, including diluted bitumen, do not contain more water than other crude oils transported in U.S. transmission pipelines. In the case of sediment, any amounts measured in diluted bitumen are likely to derive from the bitumen, since the diluents are largely free of sediment (as shown in Table 3-2). Some sediment sampling data are available to compare diluted bitumen with other Canadian crude oils. Figure 3-7 shows the average sediment levels for

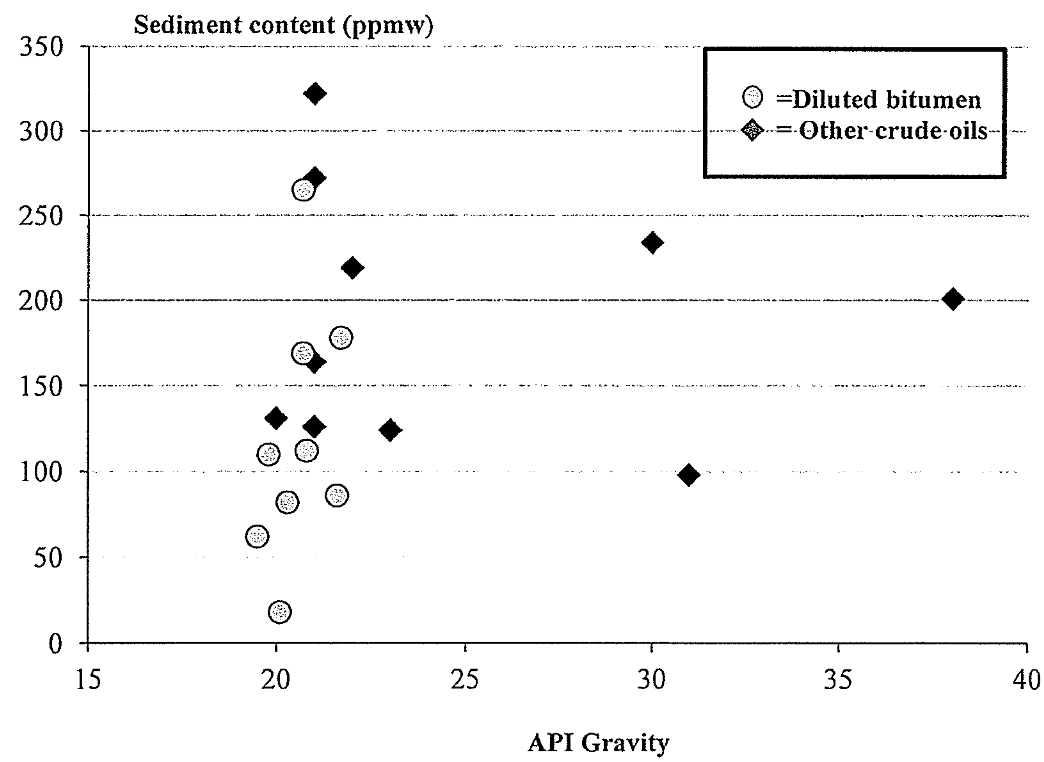

FIGURE 3-7 Average sediment content for nine diluted bitumen blends and 10 light, medium, and heavy Canadian crude oils. [Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Accessed March 1, 2013.]

nine diluted bitumen blends and 10 light, medium, and heavy Canadian crude oils. Average sediment levels range from 18 to 265 parts per million by weight (ppmw) for the diluted bitumen and from 98 to 322 ppmw for the selection of Canadian crude oils.[24] Sediment quantities in this general range (<500 ppmw) will constitute less than 0.05 percent of the crude oil stream. The comparisons suggest that shipments of diluted bitumen contain sediment levels that are within the range of other crude oils piped into the United States.

Other characteristics of entrained sediments, such as the size, shape, mass, and hardness of solid particles, are seldom measured in pipeline shipments or reported in standard crude oil assays. Particle size is a potentially important factor in the tendency of sediments to clog pumps and other pipeline equipment and settle to the pipe bottom to form sludge. The shape, mass, and hardness of solid particles in sediment can also affect the potential for internal erosion.

While data on physical properties are limited, some values for particle size and other properties have been reported in laboratory studies of diluted bitumen and other crude oils. Figure 3-8 shows the particle size distribution of solids in diluted bitumen as measured by McIntyre et al. (2012). Median particle size was 0.1 micron (μm) and rarely exceeded 1 μm. Other data indicate that the distribution of particle size observed by McIntyre et al. (2012) is well within the range of other crude oils shipped by pipeline. The Canadian Crude Quality Technical Association (CCQTA) has spot sampled the desalter effluent from three refineries in Canada and the United States. The effluent was derived from crude oils other than diluted bitumen. The

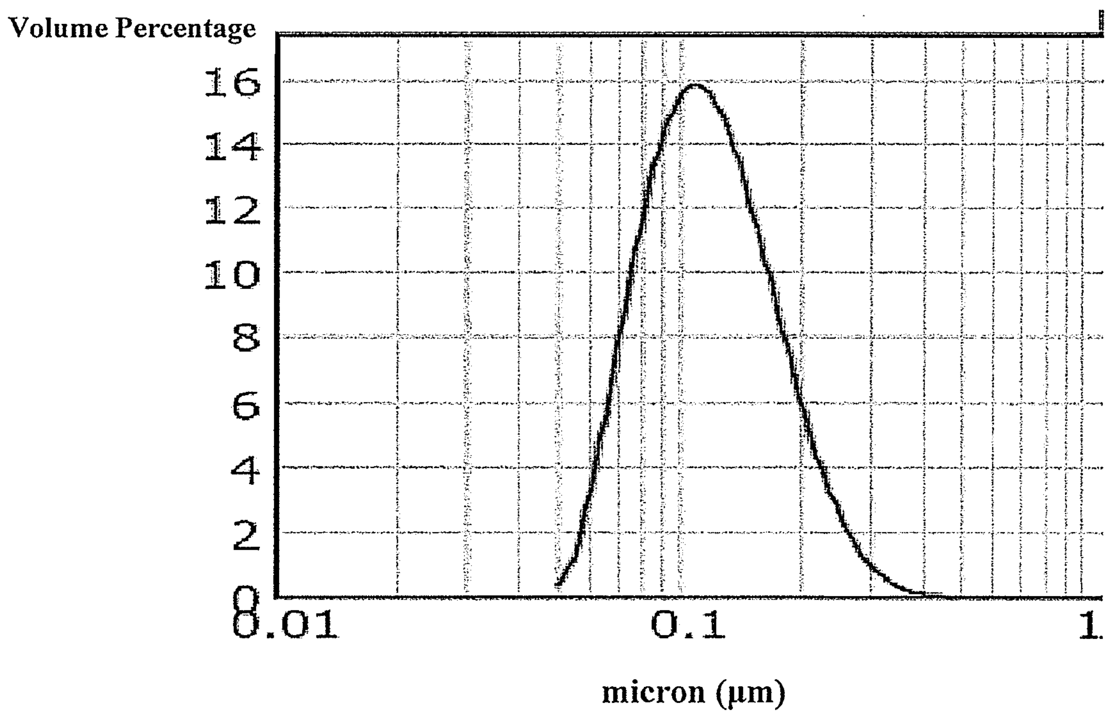

FIGURE 3-8 Particle size distribution of solids in diluted bitumen. (Source: McIntyre et al. 2012.)

[24] Most contaminants are expressed as parts per million (ppm), which is 1 milligram per kilogram for weight (noted as 1 ppmw) or 1 milligram per liter for volume (noted as 1 ppmv). 1,000 ppmw = 0.1 percent of weight.

particle size distributions from these samples are shown in Table 3-5. The median particle sizes for the samples ranged from about 0.4 to 1.6 μm, higher than the median particle size reported for the diluted bitumen sampled by McIntyre et al. (2012).

CCQTA data on the nature of solids filtered from five diluted bitumen and two heavy crude oil samples show median particle sizes that are comparable across the samples, ranging from 1.0 to 2.4 microns for four of the five diluted bitumen samples and from 1.9 to 2.3 microns for the two heavy crude oil samples.[25] The fifth diluted bitumen sample had a median particle size of 5.6 microns. The maximum particle sizes in the five diluted bitumen samples ranged from 11 to 92 microns, while the maximum value for the two heavy crude oils was 33 microns. Data are more limited for characterizing the shape, mass, and hardness of solids in diluted bitumen and other crude oils. As noted earlier, the sand grains in unprocessed bitumen contain hard silicate minerals such as quartz, feldspar, and mica, in addition to the softer minerals found in clay fines (Strausz and Lown 2003, 31–32). However, the in situ–produced bitumen that is processed and diluted for pipeline transportation does not contain the same high levels of sand, clay fines, and other sediments found in bitumen in its native state. McIntyre et al. (2012) reported that about 1 percent of the solids in sampled diluted bitumen consisted of quartz, while clay materials (16 percent) and hydrocarbon and coke-like materials (83 percent) accounted for the remainder. X-ray diffraction analysis of the solids in the five diluted bitumen and two heavy oil samples taken by CCQTA indicate that silicate particles are more abundant in the solids of diluted bitumen (accounting for 13 to 45 percent of crystalline solids) than in the solids of other heavy crude oils sampled (accounting for 5 to 8 percent of crystalline solids).[26] However, the five diluted bitumen samples did not contain high levels of sediment, with none exceeding 350 ppmw (0.035 percent).

TABLE 3-5 Size Distribution of Solid Particles Obtained from Refinery Effluent for Crude Oils Other Than Diluted Bitumen

	Refinery A					Refinery B			Refinery C
Particle Size (μm)	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 1	Sample 2	Sample 3	Sample 1
Mean	0.85	1.1	1.13	0.74	1.14	2.67	1.23	0.82	0.98
Mode	0.32	0.31	0.28	0.33	0.39	2.33	0.26	0.53	0.54
Median	0.66	0.86	0.76	0.49	0.81	1.61	0.8	0.43	0.84
Minimum	0.13	0.17	0.13	0.06	0.13	0.06	0.1	0.07	0.15
Maximum	3.38	4.5	9.74	4.0	6.55	21.59	13.3	17.7	4.64
Standard deviation	0.55	0.76	1.05	0.67	0.9	3.09	1.3	1.36	0.6

SOURCE: Data provided by CCQTA and derived from Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf).

[25] Data obtained from the CCQTA Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf).

[26] Data obtained from the CCQTA Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf). According to the CCQTA representative presenting the data, X-ray diffraction analysis does not measure the noncrystalline solids, which can account for 30 percent or more of the solids of sediment.

Other Properties

Pipeline tariffs in Canada and the United States generally do not contain specifications for shipment properties apart from those discussed above, although crude oil producers and refiners may have private agreements that specify qualities such as acidity and sulfur content. Table 3-6 shows the acidity and sulfur content for several sampled Canadian heavy crude oils and diluted bitumen blends.

The acidity of crude oil is generally referenced by using total acid number (TAN), a measure of the amount (in milligrams) of potassium hydroxide (KOH) needed to neutralize the acid in a gram of oil. TAN usually increases with the extent of oil biodegradation and generally is in the range of 0.5 to 3.0 for heavy oils (Strausz and Lown 2003, 430). Although it overlaps with the range of TANs found in heavy Canadian crude oils (as shown in Table 3-6), the range of acid content in diluted bitumen blends is generally higher than the range in other crude oils because of the greater biodegradation of the natural bitumen and resulting concentrations of high-molecular-weight organic acids.

The type of acid in diluted bitumen is more important to pipeline operators than total acid content. High-molecular-weight organic acids, such as naphthenic acids, are stable in the

TABLE 3-6 Sulfur and Total Acid Content in Sampled Canadian Heavy Crude Oils and Diluted Bitumen Blends

	Total Sulfur (percentage by weight)	TAN (mg KOH/g oil)
Canadian Heavy Crude Oils		
Fosterton	3.26	0.2
Lloydminster Blend	3.56	0.82
Lloydminster Kerrobert	3.12	0.92
Western Canadian Select	3.51	0.94
Diluted Bitumen Blends		
Albian Heavy Synthetic	2.5	0.57
Access Western Blend	3.93	1.72
Black Rock Seal Heavy	4.32	1.72
Cold Lake	3.75	0.99
Christina Lake	3.79	1.53
Peace River Heavy	5.02	2.5
Smiley–Coleville Heavy	2.97	0.98
Statoil Cheecham Blend	3.69	1.77
Surmount Heavy Blend Synbit	3.02	1.38
Western Canadian Blend	3.1	0.82

SOURCE: TAN data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Sulfur data obtained from Enbridge (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Accessed March 1, 2013.

pipeline transportation environment. These acids have boiling points higher than water and do not react at pipeline operating temperatures. Although the organic acids can be corrosive to metals used in refineries processing crude oils at temperatures above 300°C (570°F), they are not corrosive to steels at pipeline temperatures (Nesic et al. 2012). This distinction is discussed further in Chapter 5.

The Canadian heavy crude oils and diluted bitumen contain 2.5 to 5 percent sulfur by weight. Whereas condensate and synthetic crude oils are largely free of sulfur (as shown in Table 3-2), natural bitumen contains 4 to 6 percent sulfur. As described earlier, most of the sulfur in bitumen is bound in stable hydrocarbon structures. Sulfur levels in the 2.5 to 5 percent range, as found in processed bitumen diluted for transportation, are high for light- and medium-density crude oils but not unusual for heavy crude oils. While high sulfur content in crude oil is generally undesirable for refining, it is problematic for transmission pipelines mainly if it exists in surface-active compounds and hydrogen sulfide (H_2S). H_2S is a weak acid that is corrosive to pipelines for reasons explained in Chapter 5. Available test data on the H_2S content in crude oil indicate lower levels in diluted bitumen (less than 25 ppmw in liquid phase) than in other crude oils of various densities (Figure 3-9).

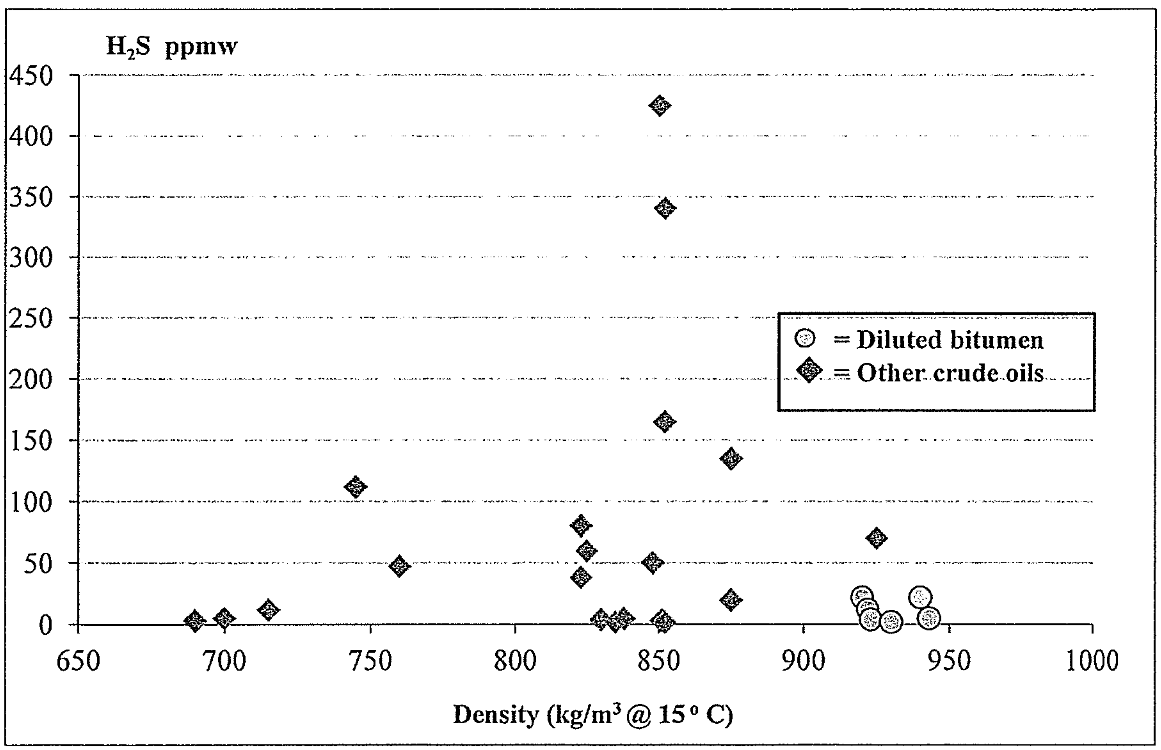

FIGURE 3-9 H_2S content of diluted bitumen and other crude oils. (H_2S is measured in liquid phase by using ASTM Test Method 5263. H_2S remains in a liquid state in pipelines because the partial pressures of operating pipelines are below the bubble point.) (Data submitted to the committee on November 13, 2012, by the Pipeline Sour Service Project Group of CCQTA.)

Shipment Properties and Operating Parameters Reported by Operators

For additional data on the transport properties of diluted bitumen, the committee prepared a questionnaire for the Canadian Energy Pipeline Association (CEPA). CEPA distributed the questionnaire to member companies that regularly transport diluted bitumen by transmission pipeline. The questionnaire and responses from five Canadian operators are provided in Appendix A. A summary of the operator responses on the properties of diluted bitumen is provided in Table 3-7. All of the reported values for BS&W, H_2S, sulfur, density, TAN, and operating temperature are within the ranges provided in the preceding tables and figures.

With respect to the pipeline flow regime, the surveyed pipeline operators reported average flow velocities of 0.75 to 2.5 meters per second (2.5 to 6.7 feet per second) in transmission pipelines that mostly range in diameter from 20 to 42 inches but that include some mileage consisting of pipe having smaller (8 inches) and larger (up to 48 inches) diameters. Without knowledge of the pipe diameter associated with each reported flow velocity, the resulting flow cannot be verified as turbulent. In general, flow velocities ranging between 0.75 and 2.5 meters per second would be expected to maintain turbulent flow in pipelines ranging from 8 to 48 inches in diameter when they transport crude oils with the range of viscosities (113 to 153 cSt at 20°C) reported for the diluted bitumen and other heavy crude oils shown in Table 3-4.

The committee asked pipeline operators for information on the content of oxygen and carbon dioxide in shipments because these dissolved gases can be an important factor in the corrosion of pipe steel, for reasons explained in Chapter 5. Pipeline operators do not routinely measure oxygen and carbon dioxide concentrations in crude oil shipments because of the difficulty associated with sampling and detecting these gases. Nevertheless, the operators reported that because diluted bitumen and other crude oils enter the pipeline system deaerated, there should be no significant difference in the concentrations of oxygen and carbon dioxide gas in products transported in the same pipelines. Operators also reported that as a general matter they aggressively seek to limit avenues for air entry into the pipeline at all times, including periods of storage and blending and pumping operations.

TABLE 3-7 Properties and Operating Parameters of Diluted Bitumen Shipments Reported by Five Canadian Pipeline Operators

Property or Parameter	Unit	Range of Reported Averages	Lowest and Highest Values in Reported Normal Ranges	Highest Reported Extremes
BS&W	Volume percent	0.18 to 0.35	0.05 to 0.40	0.50
H_2S	ppmw	<0.50 to 6.77	<0.50 to 11.0	11.0
Sulfur	Weight percent	3.10 to 4.00	2.45 to 4.97	5.20
Density	API gravity	19.8 to 22.1	19.0 to 23.3	23.3
TAN	mg KOH/g	1.00 to 1.30	0.85 to 2.49	3.75
Operating temperature	°C (°F)	10 to 27 (50 to 81)	4 to 43 (39 to 109)	50 (122)
Flow rate	feet/second	2.5 to 6.7	0.5 to 8.2	8.2
Pressure	psi	430 to 930	43.5 to 1,440	1,440

NOTE: Operators reported that oxygen and carbon dioxide concentrations are not routinely measured in shipments of crude oil. See Appendix A for complete survey results.

SUMMARY

The bitumen imported into the United States is produced from Canadian oil sands. The bitumen is both mined or recovered in situ by using thermally assisted techniques. Because a large share of the bitumen deposits is too deep for mining, in situ recovery accounts for an increasing percentage of production. Because mined bitumen does not generally have qualities suitable for pipeline transportation and refinery feed, it is processed in Canada into synthetic crude oil. Bitumen recovered through use of thermally assisted methods has water and sediment content that is sufficiently low for long-distance pipeline transportation. The bitumen imported for refinery feed in the United States is recovered through in situ methods rather than mining.

Like all forms of petroleum, Canadian bitumen is a by-product of decomposed organic materials and thus a mixture of many hydrocarbons. The bitumen contains a large concentration of asphaltenes and other complex hydrocarbons that give bitumen its high density and viscosity. At ambient temperatures, bitumen does not flow and must be diluted for transportation by unheated pipelines. The diluents consist of light oils, including natural gas condensate and light synthetic crude oils. Although the diluents consist of low-molecular-weight hydrocarbons, diluted bitumen does not contain a higher percentage of these light hydrocarbons than do other crude oils. The dilution process yields a stable and fully mixed product for shipping by pipeline with density and viscosity levels in the range of other crude oils transported by pipeline in the United States.

Shipments of diluted bitumen are transported at operating temperatures, flow rates, and pressure settings typical of crude oils with similar density and viscosity. Water and sediment content conforms to the Canadian tariff limits, which are more restrictive than those in U.S. pipeline tariffs. Solids in the sediment of diluted bitumen are comparable in quantity and size with solids in other crude oils transported by pipeline. While the sulfur in diluted bitumen is at the high end of the range for crude oils, it is bound in stable hydrocarbon compounds and is not a source of corrosive hydrogen sulfide. Diluted bitumen has higher total acid content than many other crude oils because of relatively high concentrations of high-molecular-weight organic acids that are not reactive at pipeline temperatures.

REFERENCES

Abbreviations

API	American Petroleum Institute
CAPP	Canadian Association of Petroleum Producers
ERCB	Energy Resources Conservation Board
NEB	National Energy Board
USGS	U.S. Geological Survey
WEC	World Energy Council

API. 2013. Diluted Bitumen. March 20. http://www.api.org/~/media/Files/Oil-and-Natural- CAPP. 2013. *Technical Bulletin: Alberta Oil Sands Bitumen Valuation Methodology*. Report 2013-9995 (updated monthly). Calgary, Alberta, Canada. http://www.capp.ca.

Cimino, R., S. Correra, A. del Bianco, and T. P. Lockhart. 1995. Solubility and Phase Behavior of Asphaltenes in Hydrocarbon Media. In *Asphaltenes: Fundamentals and Applications* (E. Y. Sheu and O. C. Mullins, eds.), Plenum Press, New York, pp. 97–130.

Dettman, H. D. 2012. Characteristics of Oil Sands Products. Presentation to Center for Spills in the Environment, Oil Sands Products Training, Portland, Maine, Dec. 4–5.

ERCB. 2012a. *Alberta's Energy Reserves 2011 and Supply/Demand Outlook*. Report ST98-2012. Calgary, Alberta, Canada.

ERCB. 2012b. In-Situ Process: Steam-Assisted Gravity Drainage. Calgary, Alberta, Canada.

ERCB. 2013. Upgrading and Refining. Calgary, Alberta, Canada, March 31.

Gogoi, B. K., and R. L. Bezbaruah. 2002. Microbial Degradation of Sulfur Compounds Present in Coal and Petroleum. In *Biotransformations: Bioremediation Technology for Health and Environmental Protection* (R. D. Stapleton and V. P. Singh, eds.), Elsevier, pp. 427–456.

Leontaritis, K., and G. Mansoori. 1988. Asphaltene Deposition: A Survey of Field Experiences and Research Approaches. *Journal of Petroleum Science and Engineering*, Vol. 1, No. 3, pp. 229–239.

Maqbool, T., A. T. Balgoa, and H. S. Fogler. 2009. Revisiting Asphaltene Precipitation from Crude Oils: A Case of Neglected Kinetic Effects. *Energy and Fuels*, Vol. 23, pp. 3681–3686.

McIntyre, D. R., M. Achour, M. E. Scribner, and P. K. Zimmerman. 2012. Laboratory Tests Comparing the Corrosivity of Dilbit and Synbit with Conventional Crudes Under Pipeline Conditions. Paper 2012-05. *Proc., 2012 Northern Area Eastern Conference: Corrosivity of Crude Oil Under Pipeline Operating Conditions*, National Association of Corrosion Engineers International, Houston, Tex.

NEB. 2009. *Canada's Energy Future: Infrastructure Changes and Challenges to 2020*. Calgary, Alberta, Canada.

Nesic, S., S. Richter, W. Robbins, F. Ayello, P. Ajmera, and S. Yang. 2012. Crude Oil Chemistry on Inhibition of Corrosion and Phase Wetting. Paper 2012-16(c). *Proc., 2012 Northern Area Eastern Conference: Corrosivity of Crude Oil Under Pipeline Operating Conditions*, National Association of Corrosion Engineers International, Houston, Tex.

Rahimi, P. M., R. E. Ellenwood, R. J. Parker, J. M. Kan, N. Andersen, and T. Dabros. 1998. Partial Upgrading of Athabasca Bitumen Froth by Asphaltene Removal. Paper 1998.074. *Proc., 7th UNITAR International Conference for Heavy Crude and Tar Sands*, Beijing, Oct. 27–30. http://www.oildrop.org/Lib/Conf/7thtoc.html.

Rahimi, P. M., and T. Gentzis. 2006. The Chemistry of Bitumen and Heavy Oil Processing. In *Practical Advances in Petroleum Processing* (C. S. Hsu and P. R. Robinson, eds.), Springer, pp. 148–186.

Raicar, J., and R. M. Procter. 1984. Economic Considerations and Potential of Heavy Oil Supply from Lloydminster—Alberta, Canada. In *Second UNITAR International Conference on Heavy Crude and Tar Sands* (R. F. Meyer, J. C. Wynn, and J. C. Olson, eds.), McGraw-Hill, New York, pp. 212–219.

Saniere, A., I. Hénaut, and J. Argiller. 2004. Pipeline Transportation of Heavy Oils: A Strategic, Economic and Technological Challenge. *Oil and Gas Science and Technology—Revue d'IFP Energies nouvelles*, Vol. 59, No. 5, pp. 455–466.

Schermer, W. E. M., P. M. J. Melein, and F. G. A. van den Berg. 2004. Simple Techniques for Evaluation of Crude Oil Compatibility. *Petroleum Science and Technology*, Vol. 22, Nos. 7–8, pp. 1045–1054.

Strausz, O. P., and E. M. Lown. 2003. *The Chemistry of Alberta Oil Sands, Bitumen, and Heavy Oils*. Alberta Energy Research Institute, Calgary, Canada.

Strausz, O. P., E. M. Lown, A. Morales-Izquierdo, N. Kazmi, D. S. Montgomery, J. D. Payzant, and J. Murgich. 2011. Chemical Composition of Athabasca Bitumen: The Distillable Aromatic Fraction. *Energy and Fuels*, Vol. 25, No. 10, pp. 4552–4579.

USGS. 2006. National Assessment of Oil and Gas Fact Sheet: Natural Bitumen Resources of the United States. Fact Sheet 2006-3133. U.S. Department of the Interior, Nov.

WEC. 2010. *2010 Survey of Energy Resources*. London. http://www.worldenergy.org/documents/ser_2010_report_1.pdf.

4

Review of Pipeline Incident Data

This chapter reviews U.S. and Canadian pipeline incident statistics and investigations for insight into whether transmission pipelines experience more releases when they transport diluted bitumen than when they transport other crude oils.

U.S. AND CANADIAN INCIDENT DATA

The Pipeline and Hazardous Materials Safety Administration (PHMSA) requires that all regulated pipeline operators report unintended releases that meet certain thresholds of release quantities or impact severity. PHMSA tracks and analyzes these reports to inform its inspection, investigation, and enforcement activities.[1] PHMSA inspectors also conduct more in-depth investigations of selected incidents. Incidents involving especially severe consequences, such as deaths, injuries, evacuations, and environmental damage, may also be investigated by the National Transportation Safety Board (NTSB). Through field and forensic investigations, NTSB assesses both causal and contributing factors and recommends preventive and follow-up actions, including regulatory responses.[2] The National Energy Board (NEB) and Transportation Safety Board (TSB) serve similar functions, respectively, for incidents involving pipelines in Canada. PHMSA and NEB incident statistics and investigations, as well as relevant investigations by NTSB and TSB, are reviewed next.

PHMSA Incident Data and Investigations

PHMSA regulations require that operators of hazardous liquid pipelines, which include crude oil pipelines, report any incident that involves a release of 5 gallons or more or explosion, fire, serious injury, or significant property damage.[3] Incidents that involve any component of the pipeline facility, including line pipe, tanks, valves, manifolds, and pumps, must be reported. A short reporting form is required for notifying the agency of small releases, and a longer form is required for larger releases and any release into water exceeding 5 gallons. Before 2002 the threshold for reporting releases was 50 barrels. The reporting changes make comparisons of recent release data with historical performance difficult. A further complication of the reporting system is that while PHMSA reporting covers most crude oil pipelines, there are exceptions to coverage, such as some intrastate pipelines and gathering systems.

The number of incidents reported for regulated crude oil pipelines during 2002 to 2011 is shown in Figure 4-1. During the 10-year period, the number of large incidents fluctuated from about 80 to 120 per year. Total releases trended downward from about 190 to 150 per year, with small releases accounting for between one-third and one-half of the total. System components involved in the releases are shown in Figure 4-2. Main-line pipe and tanks were involved in

---

[1] More discussion of PHMSA safety oversight programs can be found in Appendix B.
[2] NTSB recommendations pertaining to PHMSA's pipeline safety authorities can be found at http://www.phmsa.dot.gov/pipeline/regs/ntsb.
[3] 49 CFR 195.50.

about one-third of the incidents, while all other equipment, such as pumps, valves, and fittings, accounted for the rest. A generalization that can be made is that the larger releases tend to be associated with main-line pipe, and sometimes with tanks, whereas the other system components tend to experience smaller releases on average. For 2002 to 2012, the pattern of releases by system component and cause is shown in Figure 4-3 and Table 4-1. The causal distribution differed by component. For main-line pipe, internal corrosion was the cause of about one-third of releases, while external corrosion and outside force damage accounted for most of the remainder. For most other pipeline components, incorrect operation and malfunctioning equipment were the main causes of incidents. Most of the corrosion-related incidents reported to PHMSA occurred in pipes and pumps. Main-line pipe was the dominant location for external corrosion. Whereas main-line pipe also accounted for about one-third of incidents involving internal corrosion, more of these incidents occurred in pumps.

Each year, PHMSA inspectors select as many as two dozen pipeline incidents for more thorough investigation on the basis of the severity of the consequences, the nature of the suspected failure modes, and the incident and compliance history of the pipeline system involved. The investigations normally consist of site visits, forensic tests, interviews with operating personnel, and reviews of operator records. Since 2005, PHMSA has conducted 63 investigations of natural gas and hazardous liquid pipelines, including 14 incidents involving onshore crude oil transmission pipelines.[4] The latter incidents are referenced in Table 4-2. In the

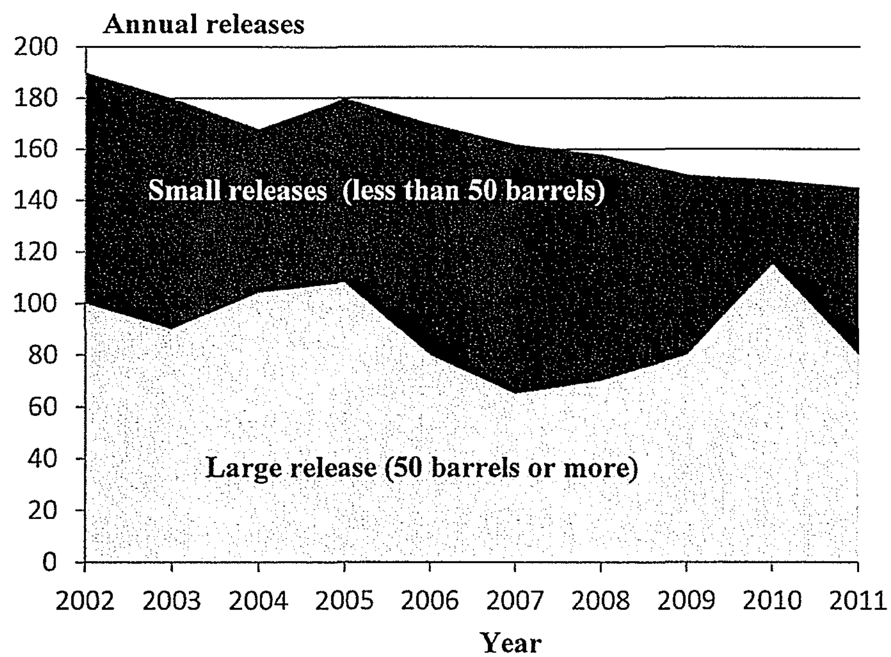

FIGURE 4-1 Crude oil pipeline incidents reported to PHMSA, 2002 to 2011. (Incident data were provided to the committee by PHMSA during the October 23, 2012, committee meeting.)

[4] http://phmsa.dot.gov/pipeline/library/failure-reports.

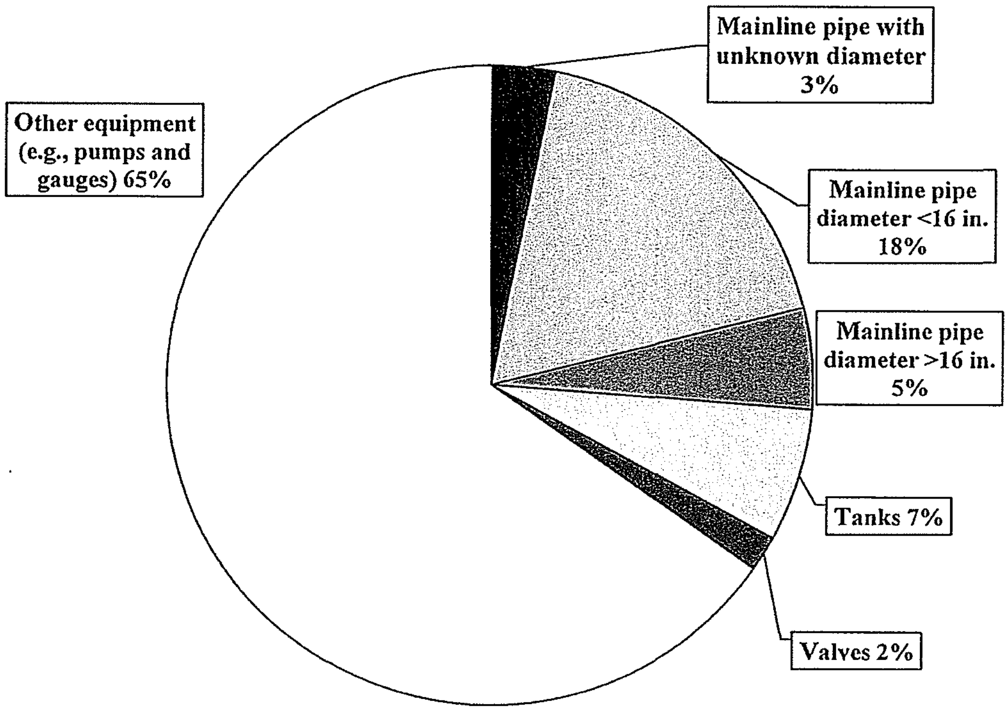

FIGURE 4-2 Crude oil pipeline incidents reported to PHMSA by system component involved, 2002 to 2012. [Data were obtained from analysis of PHMSA data from the Environmental Impact Statement of TransCanada XL permit application (U.S. Department of State 2013, Volume IV, Appendix K).]

two cases found to have involved internal corrosion, factors other than the properties of the crude oils transported were cited as causes. In three other cases, investigators reported that internal pressure cycles and associated stress loadings may have contributed to the formation and growth of cracks initiated at sites of external corrosion.

Apart from providing some examples of possible failures related to the transported product, the PHMSA investigations do not provide evidence that pipelines transporting diluted bitumen are more susceptible to release. In the next chapter, the chemical and physical properties of diluted bitumen are examined to deduce possible susceptibilities to pipeline damage.

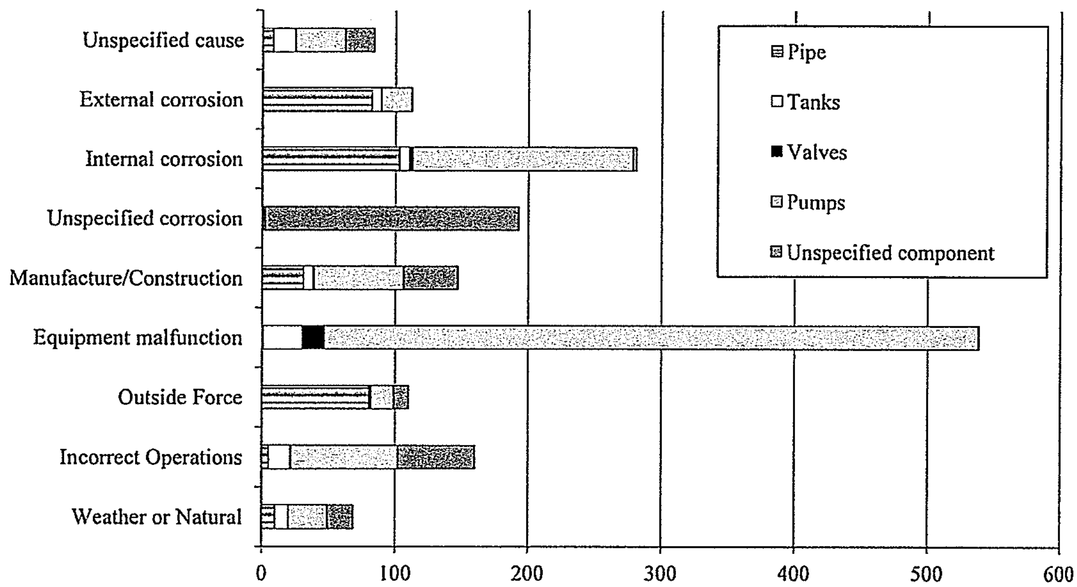

FIGURE 4-3 Crude oil pipeline incident reports to PHMSA by cause of release and system component involved, 2002 to 2012. (Source: U.S. Department of State 2013, Volume IV, Appendix K.)

TABLE 4-1 Crude Oil Pipeline Incident Reports to PHMSA by Cause of Release and System Component Involved, 2002 to 2012

Reports of Pipeline Releases to PHMSA, 2002–2012						
	Pipe	Tanks	Valves	Pumps	Unspecified Component	Total
Weather or natural force	10	10	0	29	20	69
Incorrect operations	5	16	1	80	58	160
Outside force	80	0	2	17	11	110
Equipment malfunction	1	29	17	491	1	539
Manufacture or construction	31	7	1	67	41	147
Unspecified corrosion	1	1	0	0	191	193
Internal corrosion	103	7	3	165	3	281
External corrosion	82	7	0	23	0	112
Unspecified cause	8	16	1	37	22	84
Total	321	93	25	909	347	1,695

SOURCE: U.S. Department of State 2013, Volume IV, Appendix K.

TABLE 4-2 PHMSA Crude Oil Pipeline Incident Investigations, 2005 to 2012

Date of Failure	Operator	Location	Commodity Released	System Component	Attributed Cause	Summary
4/12/05	Jayhawk Pipeline	Stevens, Kansas	Crude oil	7-in. main-line pipe section	Internal corrosion	Sand and saltwater collected in a low point in the pipeline, resulting in corrosive conditions.
1/1/07	Enbridge Energy Partners	Clark County, Wisconsin	Crude oil from Canada	24-in. main-line pipe section	Defect in manufacture	Weld seams did not fuse during pipe manufacture. The defect grew to a critical size by fatigue from operating pressure cycles.
11/13/07	Enbridge Energy Partners	Clearbrook, Minnesota	Crude oil from Canada	34-in. main-line pipe section	Defect in manufacture	Pipe was transported to the construction site on rail cars, causing fatigue cracks from cyclical loading. Pressure cycling during operations may have caused the cracks to grow to failure.
2/18/09	Mid-Valley Pipeline	Cygnet, Ohio	Crude oil	12-in. branch connection to main line	Material failure	The combined loading of the branch connection, valve, and flanging caused the branch attachment to crack at the weld.
6/9/09	Enbridge Energy Partners	Gowan, Minnesota	Crude oil from Canada	26-in. main-line pipe section	Material failure	A sleeve installed 20 years earlier to repair a pipe split opened at a deficient weld.
12/23/09	Enterprise Products	Galveston, Texas	Crude oil from offshore	Meter station component	Material failure in a fitting	Cap screws on a stainless steel pressure switch failed because of hydrogen-assisted cracking promoted by galvanic corrosion.
3/1/10	Mid-Valley Pipeline	Gregg County, Texas	Crude oil	Tank farm manifold piping	Internal corrosion	Internal corrosion occurred in a dead-leg section of pipe with no flow during normal operations.
6/11/10	Chevron Pipe Line	Salt Lake County, Utah	Crude oil	10-in. main-line pipe section	Outside force damage	An electric charge jumped from a metal fence to the pipe, creating a 0.5-in. hole in the top of the pipe.
6/14/10	Suncor Energy Pipeline	Laramie, Wyoming	Crude oil	Breakout tank	Incorrect operation	Operating personnel did not respond to an alarm indicating tank capacity had been reached.

(*continued*)

TABLE 4-2 (*continued*) **PHMSA Crude Oil Pipeline Incident Investigations, 2005 to 2012**

Date of Failure	Operator	Location	Commodity Released	System Component	Attributed Cause	Summary
11/16/10	Shell Pipeline	Vinton, Louisiana	Crude oil from offshore	22-in. main-line pipe section	Material failure	The coating disbonded at a bend in the pipe allowing the onset of corrosion. Cyclical loading due to normal batch operations may have contributed to crack growth.
12/1/10	Chevron Pipe Line	Salt Lake County, Utah	Crude oil (condensate)	Valve used for water injection in main line	Incorrect operation	Water was not properly drained from the valve. Internal pressure brought on by freezing water caused the valve connection to leak.
1/26/11	Chevron Pipe Line	Plaquemines Parish, Louisiana	Crude oil from offshore	10-in. main-line pipe section at river crossing	Excavation damage	The pipeline was being lowered while in service. Stress concentrations from the procedure caused fracturing in an area with preexisting dents.
2/21/11	Enterprise Products	Cushing, Oklahoma	Crude oil	8-in. pipe within terminal area	Incorrect operation	Personnel purging a pipe failed to shut down the pump, which resulted in the delivery being pumped against a closed valve, causing a pipe with preexisting manufacturing defects to fail.
7/1/11	ExxonMobil Pipeline	Laurel, Montana	Crude oil	12-in. main-line pipe section	Outside force damage	River flooding caused debris to strike and rupture the line.

SOURCE: PHMSA's pipeline failure investigation reports can be found at http://phmsa.dot.gov/pipeline/library/failure-reports.

NEB Incident Statistics

NEB regulates interprovincial pipelines in Canada. The regulated network consists of 11,000 miles of crude oil pipeline, nearly all of which are in transmission systems. Regulated operators must file an "accident" record if a pipeline facility experiences a fatal or serious injury, fire, or explosion due to a release; any other damage to the pipeline that causes a release; and any form of outside force damage, even if it does not lead to a release. In addition, operators are required to file an "incident" report in the event of an uncontrolled release, operations that exceed design limits, an abnormality that reduces structural integrity, or a shutdown for safety reasons. These reported incidents do not necessarily involve releases.

From 2004 to 2011,[5] NEB received 12 accident reports and 292 incident reports involving crude oil transmission pipelines (TSB 2012, Table 5). Of the 292 incidents involving pipeline integrity issues—such as internal and external degradation—cracks accounted for the largest share, almost 30 percent (see Figure 4-4). Metal loss, mainly from corrosion, was reported in 16 percent of incidents. Of the 12 accident reports, one involved combined corrosion and cracking (stress corrosion cracking), as discussed in more detail below.

NTSB and TSB Investigations

The main transportation safety investigative bodies in the United States and Canada are NTSB and TSB, respectively. Although their pipeline investigations are thorough, they are infrequent and selective. For example, over the past decade NTSB has investigated fewer than a dozen

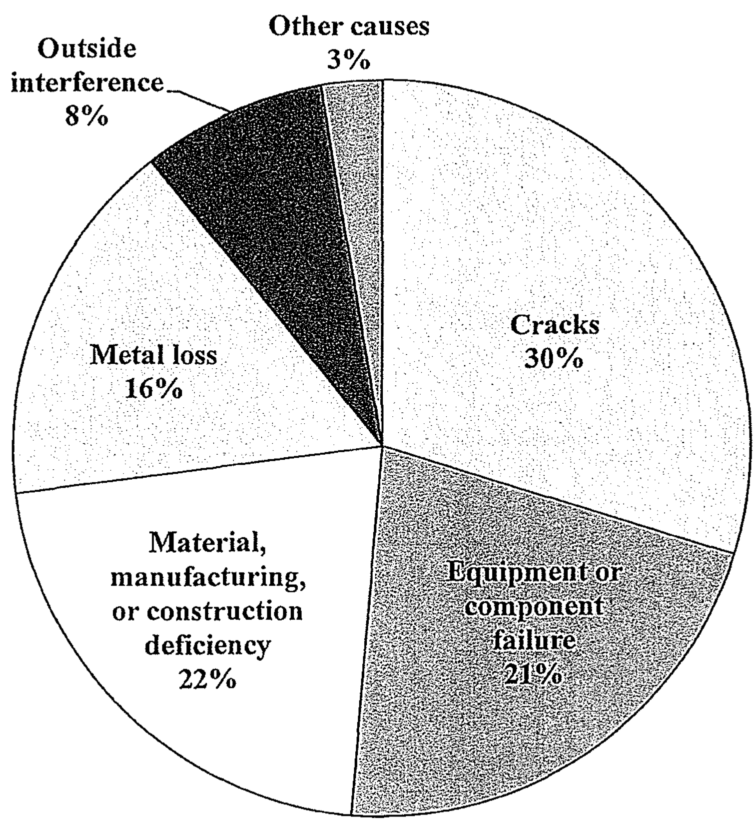

FIGURE 4-4 Causes of crude oil transmission pipeline incidents reported to NEB, 2004 to 2011. (Source: TSB 2012, Table 5.)

[5] Before 2004, the definition of reportable incident used by NEB was different from that used today. The reporting change makes longer-term trend analysis less meaningful.

pipeline incidents, most involving pipelines carrying volatile commodities such as natural gas and refined products.[6] The investigations are helpful in understanding factors that can interact to cause pipeline damage and failures, but they produce limited information useful in assessing the effect of specific crude oil types or crude oil properties on pipeline release probabilities.

In 2012, NTSB completed an investigation of a pipeline failure in which diluted bitumen was reported to have been released. The incident involved a 30-inch transmission pipeline that ruptured and released 20,000 barrels of product into a river near Marshall, Michigan (NTSB 2012). The investigators determined that the cause of the rupture was cracks that had formed in a corrosion pit on the outside of the pipe under a disbonded polyethylene tape coating. The cracks coalesced and grew as a result of stresses on the pipe, a process known as environmentally assisted cracking (EAC), which is described in more detail in Chapter 5. The Marshall release attracted considerable attention because of the consequences of the release and the actions of the operator. However, NTSB did not report that specific properties of the products transported through the pipeline at the time of the event or in the past had caused or contributed to the pipeline damage.

As noted above, one of the 12 crude oil pipeline accidents reported to NEB since 2004 involved a corroded and cracked pipeline. This release, which occurred in 2007, was investigated by TSB.[7] The release was from a 34-inch transmission pipeline originating in Alberta and transporting crude oil to the United States (TSB 2007). A forensic analysis of the ruptured pipe joint detected a shallow corrosion pit at a weld on the outside of the pipe that led to a stress corrosion crack, which eventually spread and fractured the pipe. TSB investigators determined that the polyethylene tape coating had tented over the weld, shielding the pipe from the beneficial effects of the cathodic protection current.[8] The corrosion pit that developed because of the tape failure became a stress concentration site where cracks formed and grew. TSB noted that 2 years earlier the operator had converted the pipeline to batch operations and surmised that this operational change may have contributed to crack growth as a result of more cyclic stress loadings from internal pressure fluctuations. Whether specific varieties of crude oil in the stream had properties that contributed to more severe pressure cycling was not reported by TSB.

A review of other NTSB and TSB investigations over the past decade did not indicate any cases in which specific crude oil types or shipment properties were associated with causes of pipeline damage or failure.

Assessment of Information from Incident Reports

The causes of pipeline incidents reported to PHMSA are proximate and broadly categorized. Incidents categorized as corrosion damage, for example, do not distinguish among those occurring as a result of the action of microorganisms, in combination with stress cracking, or at sites of preexisting mechanical damage. Some types of damage, such as EAC, may be categorized alternatively as caused by corrosion, a manufacturing defect, or a material failure. Whereas NTSB and TSB investigations provide detailed information on factors causing and

[6] NTSB pipeline investigation reports are available at http://www.ntsb.gov/investigations/reports_pipeline.html.

[7] NEB may conduct its own investigations of a reported incident to ensure that safety regulations are being followed and to determine the need for remedial actions.

[8] When the tape disbonds from the pipe steel, moisture can accumulate beneath the tape surface. Because the tape has fairly high electrical insulation properties, it can prevent cathodic protection current from reaching the exposed steel subject to corrosion.

contributing to pipeline releases, the investigations are too few in number to assess the causal effects of specific crude oil types and their properties.

Because of the potentially large number of factors associated with a given release, it is often difficult to isolate the role of any single causative factor, such as the effect of the specific crude oil being transported on time-dependent mechanisms such as corrosion and cracking. Sources of pipeline damage affected by the crude oils transported, either at the time of the release or in earlier shipments, are most pertinent to this study. Neither PHMSA nor NEB incident data contain informationon the types of crude oils transported or the properties of past shipments in the affected pipeline.

STATE AND PROVINCIAL INCIDENT DATA

Some U.S. states and Canadian provinces maintain reporting systems for incidents in intrastate and intraprovincial pipeline systems, including gathering lines. The Energy Resources Conservation Board (ERCB) holds this responsibility in Alberta. In the United States, several state regulators have authority over intrastate pipelines, including the state fire marshal of California. Pipeline incident data and analyses derived from both of these jurisdictions were considered.

Alberta ERCB Incident Data

The Alberta ERCB regulates and monitors the safe performance of oil pipelines in the province, with the exception of approximately 700 miles of NEB-regulated transmission pipeline crossing into other provinces and the United States.[9] ERCB mandates reporting of all pipeline incidents involving a release or damage from an outside force. In 2007, the agency reviewed the causes of 411 crude oil pipeline incidents reported from 1990 to 2005 (EUB 2007). The ERCB analysis showed that the largest single cause was internal corrosion, which the agency ascribed to the effects of the large percentage of gathering pipelines in the province. These small-diameter lines were described as susceptible to internal corrosion because of repeated low-flow conditions; frequent stopping and idling of movements; and the mixture of raw crude oil, gases, sediments, and waters carried from production fields (EUB 2007, 30). About 29 percent of the roughly 11,000 miles of ERCB-regulated pipeline mileage consisted of pipe with a diameter of 4 inches or less, and 73 percent had a diameter of 12 inches or less. Only about 1 percent of the mileage consisted of pipelines having a diameter of more than 22 inches.

Although ERCB release statistics have at times been cited as evidence of a corrosive effect of diluted bitumen on pipelines (Swift et al. 2011), the regulated systems represented by these incident statistics are not comparable with transmission pipelines in size, operations, or, most important, contents. As a result, the committee concluded that the ERCB data were not useful for the purposes of this study.

California Pipeline Safety Study

Pipeline operators in California have a long history of transporting crude oils with physical properties similar to those of Canadian crude oils and diluted bitumen. Most of the oil from the

[9] The Energy and Utilities Board regulated pipelines in Alberta until it was replaced in 2008 by ERCB.

San Joaquin Valley, for instance, has an American Petroleum Institute (API) gravity of 18 degrees or less, with the Kern River field producing especially dense crude oil with an API gravity of about 13 degrees (Sheridan 2006). Like bitumen producers, California oil producers commonly use thermal recovery techniques, such as injecting steam through the wellbore, to reduce crude oil viscosity and facilitate pumping to the surface. Heavier California crude oils are often transported undiluted through heated pipelines. This is not the case for Canadian bitumen, which is diluted for transportation.[10]

California has nearly 3,300 miles of transmission pipelines subject to federal safety regulation.[11] In addition, the state contains 3,000 to 4,000 miles of state-regulated pipeline, most of it in gathering systems. Responsibility for regulating the safety of hazardous liquid pipelines in California is shared by PHMSA and the California State Fire Marshal (CSFM).

In 1993, CSFM issued a report of the incident history of hazardous liquid pipelines in the state from 1981 to 1990 (CSFM 1993). The report examined releases from state and federally regulated lines, including those transporting refined petroleum products. Operators were required to submit records of releases during the period regardless of release quantity or consequences, along with information on pipeline diameter, length, age, operating temperature, and external coating type. Although the report is now 20 years old, its results have been cited as indicative of the potential effects of diluted bitumen on pipeline integrity (NRDC 2011).

The CSFM study documented 502 releases from hazardous liquid pipelines in California during the 10-year period. Analyses of the incident records indicated that external corrosion was the leading cause of releases, accounting for 59 percent, followed by third-party damage (20 percent), equipment malfunctions (5 percent), and weld failures (4 percent). Internal corrosion accounted for 3 percent, while operator error accounted for 2 percent.[12] Crude oil pipelines generated 62 percent of total releases, including 70 percent of the releases attributed to external corrosion.

While the CSFM study did not investigate each reported incident in depth, statistical analyses of the 502 records presented some patterns of interest. The age of the pipeline was correlated with a higher release rate. For example, 62 percent of the releases occurred in pipelines constructed before 1950, even though these lines accounted for only 18 percent of pipeline mileage. CSFM noted that many of the pipelines built in California during the first half of the 20th century lacked cathodic protection for most of their service lives, which suggests that the lack of cathodic protection, coupled with the absence of coatings or use of older coating materials, may have led to the high incidence of external corrosion relative to other failure causes.[13] The CSFM analysis revealed that 22 percent of the external corrosion incidents occurred in pipelines that were uncoated, and another 53 percent occurred in pipelines coated or wrapped with certain materials, most often asphalt and tar.

One finding that stood out among pipelines experiencing external corrosion was the disproportionate number of small-diameter pipelines that were operating at relatively high temperatures. Operating temperature was highly correlated with external corrosion—more than half the releases from external corrosion occurred in the 21 percent of pipeline mileage in which

---

[10] As discussed in Chapter 2, California oil fields are served by transmission pipelines that connect to refineries elsewhere in the state. The transmission pipelines do not cross state borders.

[11] Pipeline mileage by state is available at the following PHMSA website: http://primis.phmsa.dot.gov/comm/reports/safety/CA_detail1.html?nocache=9253#_OuterPanel_tab_5.

[12] All other causes accounted for 7 percent of releases.

[13] As is discussed in Chapter 5, some older coating technologies shield cathodic protection currents.

the operating temperature regularly reached or exceeded 55°C (130°F). In addition, a large portion of the pipelines experiencing external corrosion consisted of small-diameter pipe. Although they accounted for only 13 percent of pipeline mileage, pipelines with diameters of less than 8 inches accounted for 21 percent of external corrosion incidents. Larger pipelines, with diameters of 16 inches or more, accounted for 23 percent of mileage but only 6 percent of the external corrosion incidents.

The preponderance of external corrosion incidents in smaller-diameter pipe and pipelines with high operating temperatures does not indicate that transmission pipelines contributed to the high rate of pipeline releases in California during the 1980s. Instead, the results suggest that older lines, many of which lacked modern coatings and cathodic protection for much of their operating history, were the main source of the releases. The high operating temperatures of many of these pipelines can be attributed to the thermal recovery methods used for California crude oil production. While the California experience illustrates the problems that can arise when pipelines are not properly protected against external corrosion, it is not indicative of the protections afforded crude oil transmission pipelines today.[14]

SUMMARY

A logical step in addressing the question of whether shipments of diluted have a greater propensity to causes pipeline releases than shipments of other crude oils is to examine historical release records. The incident statistics can be used to identify the general sources of pipeline failure. However, the information contained in the U.S. and Canadian incident records is insufficient to draw definitive conclusions. One reason is that the causal categories in the databases lack the specificity needed to assess the particular ways in which transporting diluted bitumen can affect the susceptibility of pipelines to failure. Another reason is that incident records do not contain information on the types of crude oil transported and the properties of past shipments in the affected pipeline. Because many pipeline releases involve cumulative and time-dependent damage, there is no practical way to trace the transportation history of a damaged pipeline to assess the role played by each type of crude oil and its properties in transport.

Incident reporting systems in Canada and the United States do not have uniform reporting criteria and coverage. Given the relatively small number of pipeline incidents, even minor variations in reporting criteria can lead to significant differences in incident frequencies and causal patterns. Some reporting systems combine incident reports from oil gathering and transmission systems, while others do not. Variation in reporting coverage is problematic because gathering pipelines are fundamentally different from transmission pipelines in design, maintenance, and operations and in the quality and quantity of the liquids they carry.

REFERENCES

Abbreviations

CSFM	California State Fire Marshal
EUB	Energy and Utilities Board
NRDC	Natural Resources Defense Council

[14] All hazardous liquid transmission pipelines are required by federal regulation to have cathodic protection.

NTSB	National Transportation Safety Board
TSB	Transportation Safety Board of Canada

CSFM. 1993. *Hazardous Liquid Pipeline Risk Assessment.* Sacramento, Calif. http://osfm.fire.ca.gov/pipeline/pdf/publication/pipelineriskassessment.pdf.

EUB. 2007. *Pipeline Performance in Alberta, 1990–2005.* Report 2007-A. Alberta, Canada, April. http://www.ercb.ca/reports/r2007-A.pdf.

NRDC. 2011. *Say No to Tar Sands Pipeline: Proposed Keystone XL Project Would Deliver Dirty Fuel at a High Cost.* Washington, D.C., March. http://www.nrdc.org/land/files/TarSandsPipeline4pgr.pdf.

NTSB. 2012. *Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010.* Report NTSB/PAR-12/01. Washington, D.C. http://www.ntsb.gov/doclib/reports/2012/PAR1201.pdf.

Sheridan, M. 2006. *California Crude Oil Production and Imports.* Staff Paper CEC-600-2006-006. Fossil Fuels Office, Fuels and Transportation Division, California Energy Commission, April. http://www.energy.ca.gov/2006publications/CEC-600-2006-006.pdf.

Swift, A., S. Casey-Lefkowitz, and E. Shope. 2011. *Tar Sands Pipelines Safety Risks.* Natural Resources Defense Council, National Wildlife Federation, Pipeline Safety Trust, and Sierra Club, Washington, D.C. http://www.nrdc.org/energy/files/tarsandssafetyrisks.pdf.

TSB. 2007. *Pipeline Investigation Report: Crude Oil Pipeline Rupture,*
Enbridge Pipelines, Inc., Line 3, Mile Post 506.2217, near Glenavon, Saskatchewan, 15 April 2007. Report P07H0014. http://www.bst-tsb.gc.ca/eng/rapports-reports/pipeline/2007/p07h0014/p07h0014.pdf.

TSB. 2012. *Statistical Summary, Pipeline Occurrences 2011.* Gatineau, Quebec, Canada. http://www.tsb.gc.ca/eng/stats/pipeline/2011/ss11.pdf.

U.S. Department of State. 2013. *Draft Supplementary Environmental Impact Statement for the Keystone XL Project Applicant for Presidential Permit: TransCanada Keystone Pipeline, LP.* Bureau of Oceans and International Environmental and Scientific Affairs, Washington, D.C. http://keystonepipeline-xl.state.gov/draftseis/index.htm.

5

Assessing the Effects of Diluted Bitumen on Pipelines

This chapter examines the main causes of pipeline failure and the physical and chemical properties of the transported crude oils that can affect each. The relevant properties of diluted bitumen and other crude oil shipments are compared to make judgments about whether transporting diluted bitumen increases the likelihood that a pipeline will fail. Consideration is then given to whether pipeline operators, in transporting diluted bitumen, alter their operating and maintenance procedures in ways that can inadvertently make pipelines more prone to failure.

The following sections examine the potential sources of failure in pipelines from (*a*) internal degradation, (*b*) external degradation, and (*c*) mechanical forces. Because it is exposed to the shipped liquid, the inside of the pipe is the most obvious location to look for possible sources of damage from shipments. Corrosion is the main cause of internal degradation in crude oil transmission pipelines, followed to a lesser extent by erosion. Although the outside of the pipeline is not in contact with the shipped liquid, pipeline operating conditions associated with the shipment can affect the exterior of a transmission pipeline. Corrosion and cracking are the main sources of external degradation that can be affected by these conditions. Mechanical damage to the pipeline from overpressurization and outside forces also can be affected indirectly by the liquid in the pipeline.

SOURCES OF INTERNAL DEGRADATION

Pipelines sustain internal damage primarily as a result of progressive deterioration caused by corrosion and erosion of the mild steel used to manufacture line pipe. Internal corrosion is an electrochemical process that typically causes damage to the bottom of the pipe when water is present. Erosion is a mechanical process that causes metal loss along the interior wall of the pipe because of the repeated impact of solid particles, particularly at bends and other areas of flow disturbance. Both forms of attack reduce pipe wall thickness and can penetrate the wall fully to cause leaks or decrease the strength of the metal remaining in the wall to produce a rupture. Internal corrosion is more prevalent than erosion in crude oil transmission pipelines. Both sources of internal pipeline damage are reviewed next, and the potential for diluted bitumen to affect their occurrence in crude oil transmission pipelines is assessed.

Internal Corrosion

The electrochemical process that causes iron in steel to corrode involves anodic and cathodic reactions. The main anodic reaction is the oxidative dissolution of iron. The main cathodic reaction is reductive evolution of hydrogen. The main species that contribute to a higher rate of corrosion are dissolved acid gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) as well as organic acids. For the electrochemical reactions to occur, an ionizing solvent must be present, which in the pipeline environment is usually water. Salts, acids, and bases dissolved in the water create the necessary electrolyte.

To prevent external corrosion, pipes are coated on the outside surface and cathodic protection is applied. In the case of internal corrosion, protecting the steel through the use of a coating or cathodic protection is impractical for various reasons. To prevent internal corrosion, therefore, pipeline operators try to keep water and other contaminants out of the crude oil stream and to design their systems so as to reduce places where any residual quantities can accumulate on the pipe bottom. They also use operational means to limit deposition, including maintenance of turbulent flow; periodic cleaning with pigs; and the injection of chemicals, called corrosion inhibitors, that disperse and suspend water in the crude oil and form a protective barrier on the pipe surface.

When crude oil is pumped from the ground, it is accompanied by some water and varying amounts of CO_2 and H_2S as well as certain organic acids. Crude oil producers try to minimize these impurities in delivering a stabilized product to the transmission pipeline, but eliminating them is prohibitively expensive. Transmission pipelines carrying crude oil therefore typically have some small amount of water and sediment (usually less than 1 percent by volume), and dissolved CO_2 and H_2S will exist in even smaller quantities. Of interest to this study is whether diluted bitumen contains any more of these corrosive contaminants than do other crude oils or whether these contaminants are more likely to settle and accumulate on the bottom surface of pipelines transporting diluted bitumen.

The various means by which water, sediment, dissolved gases, and other materials can cause internal corrosion of crude oil transmission pipelines are reviewed next.

Water Deposition and Wetting

Oil by itself is not corrosive to mild steel pipe in the temperature range in which transmission pipelines operate, which is typically well below 100°C. Water contact with the inside pipe wall is an essential precondition for internal corrosion. Pure water is not a significant source of corrosion when it acts alone. As discussed in more detail below, however, water in the presence of certain dissolved contaminants, such as CO_2, H_2S, and oxygen (O_2), will cause corrosion if the water is allowed to contact and wet the steel surface of the pipe. In theory, a pipeline carrying oil and a small amount of water will not experience internal corrosion if the water is dispersed and suspended in the oil rather than flowing as a separate phase in contact with the bottom of the pipe. The following factors can affect whether water falls out of the oil flow to cause water wetting of the steel surface:

- *Flow rate:* When oil and water move through a horizontal pipeline at low flow rates, gravitational force will dominate turbulent forces and cause the water to flow as a separate layer. As the rate of flow increases, the turbulence energy of the flow will increase, causing the water to become gradually more dispersed and entrained in the oil. The turbulence will cause water to break up into smaller droplets, and it will keep these finer droplets suspended.
- *Water content:* The more water present in the flow, the harder it becomes for the flowing oil to suspend all water droplets. Thus, water settles more readily when there is more of it in the pipeline stream.
- *Pipe diameter and inclination:* Water is more difficult to keep entrained as the diameter of the pipeline increases as long as other parameters remain the same, including the flow rate and physical properties of the crude oil. Pipe inclination has a comparatively small effect on the ability of oil to entrain water if the inclination is less than 45 degrees.

- *Physical properties of the oil and water:* The density and viscosity of water and oil play an important role in water entrainment and settling. In general, oils that have high density and viscosity are better able to entrain water than are lighter oils, in part because the density of a heavy oil will be close to that of water. Another important physical property is the oil and water interfacial tension, or tendency of the water and oil to mix or separate. Interfacial tension is affected by the presence of surface-active substances naturally found in the crude oil as well as by surfactant chemicals that may be injected into the flow by the pipeline operator.
- *Chemical additives:* Chemicals injected into the flow stream can significantly influence water entrainment, primarily by affecting interfacial tension. As explained in Chapter 2, pipeline operators add corrosion-inhibiting chemicals to the oil stream to adsorb onto the steel surface and provide a protective layer against corrosion and water wetting. Another benefit of these additives is that they usually contain surface-active compounds that decrease oil and water interfacial tension so as to make it more difficult for water to separate from the oil flow. Conversely, chemical demulsifiers that are added to oil to remove water during processing before delivery to the pipeline can have the undesired effect of increasing the interfacial tension and thus causing easier separation of oil and water in the pipeline flow. Finally, the drag-reducing agents that are sometimes added by pipeline operators to enhance throughput can lower the ability of flowing oil to entrain water by dampening turbulence.

Solids Deposition

Solids in the crude oil stream settle to the pipe bottom for the same hydrodynamic reasons described above for water dropout. Typically the settled solids consist of a mix of inorganic and organic components. Sand, clay, detached scale, and corrosion products (such as carbonates and sulfides) are usually the main inorganic components of settled solids. Organic components commonly consist of asphaltenic and paraffinic compounds as well as other organic material formed by the action of microorganisms (Mosher et al. 2012; Friesen et al. 2012). The corrosive effect of microorganisms in pipeline deposits is discussed in more detail later in the section.

When the flow rate and associated turbulence are low, solids can settle and accumulate, particularly at the bottom of horizontal lines. When no water is present, the deposition of solids can impede flow to create a flow assurance problem. When the solids settle with water, the mix is often referred to as sludge. A porous layer of settled solids can retard corrosion by water containing aggressive species, because the solids will cover part of the steel surface and make it harder for those species to reach the surface. However, a porous layer of solids can also impede access to the steel surface by corrosion-inhibiting chemicals. In this case, the internal surface of the pipe that is covered by a layer of solids may corrode faster than the rest of the surface not covered by solids but protected by the chemical inhibitors. This adverse effect can be compounded by an unfavorable galvanic coupling between the unprotected area covered by the solids and the surrounding areas that are chemically inhibited.

The basic sediment and water (BS&W) content of a crude oil shipment, as described in the previous chapters, is a common measure of the amount of solids and water carried and can be used to predict the likelihood of deposit formation. Even when BS&W is very low (less than 0.5 percent by volume) and the fluid velocity is relatively high (>1 meter per second or >2 miles per hour), some accumulated solids and water may be found in low spots in the pipeline and in dead legs, where the flow rate is low or stagnant. Sludge deposits holding water containing the dissolved gases, acids, and microorganisms discussed next are the source of a common form of localized internal corrosion commonly referred to as underdeposit corrosion.

Corrosive Effect of CO_2

CO_2 dissolved in water can have a particularly corrosive effect in pipelines, as evidenced by the series of reactions that ensue (DeWaard and Milliams 1975). Water containing dissolved CO_2 that forms carbonic acid (H_2CO_3) and wets the pipe surface leads to the dissolution of iron (Fe) from the pipe steel and the evolution of hydrogen (H_2) from the water. This weak acid partially dissociates in water to produce the bicarbonate ion (HCO_3^-) and protons (H); in water the protons are present as hydronium ions (H_3O^+). Bicarbonate ions dissociate further to produce more hydronium ions and carbonate ions (CO_3^{2-}). The hydronium ion is highly reactive as it seeks to obtain a missing electron from nearby species. In giving up electrons to hydronium ions, the iron atoms on the pipe surface are destabilized, and they dissolve in the water to form iron ions (Fe^{2+}). By obtaining the resulting electrons, the hydronium ions are converted to dissolved hydrogen gas (H_2). The corrosion by-product is iron carbonate ($FeCO_3$), which may deposit on the steel surface and be protective in some cases.

Keeping CO_2 out of the crude oil stream is particularly important because the ensuing corrosion process can occur rapidly. The reason is that as the hydronium ions are consumed by the corrosion reaction, the carbonic acid dissociates further to replenish the reactive ions, which allows the corrosion process to continue at a fast rate. As long as there is sufficient CO_2 to produce the carbonic acid, the iron in pipe steel that is water wet will continue to corrode. The full series of chemical reactions involved in CO_2 corrosion is detailed in Box 5-1.

Corrosive Effect of H_2S

H_2S is another gas that may be present in the crude oil stream to create corrosive conditions inside pipelines when it is dissolved in water. Crude oil is often extracted with some amount of H_2S. The concentrations in crude oil can be small [less than 100 parts per million (ppm) in the gas phase] or substantially larger. Other sulfur compounds in crude oil are less common, and they are typically soluble in oil rather than water, requiring high temperatures (>300°C) to become reactive (Nesic et al. 2012). Thus, their concentrations do not present a corrosion problem in transmission pipelines.

The reactions that cause H_2S to corrode pipe steel are generally similar to those described for CO_2. Like CO_2, H_2S gas is soluble in water. As a weak acid, the dissolved H_2S behaves in a manner similar to carbonic acid (H_2CO_3) by providing a reservoir of reactive hydronium ions. An important difference is that the layer of protective iron sulfide (FeS) always forms on the steel surface as a result of the reactions involving H_2S. Experimental evidence indicates that H_2S corrosion initially proceeds by adsorption of the H_2S to the steel surface. This adsorption is followed by a fast surface reaction at the steel and water interface to form a thin (about 1 micron) film of the iron sulfide mackinawite (Wikjord et al. 1980). The formation of mackinawite is an important factor governing the corrosion rate because the surface film can create a barrier that impedes the ability of other species to reach the steel. Accordingly, corrosion due to other contaminants such as CO_2 can be reduced when small amounts of H_2S (in the low ppm range in the gas phase) are present in crude oil.

Box 5-1

CO_2 Corrosion of Mild Pipe Steel

CO_2 gas dissolved in water forms a weak carbonic acid (H_2CO_3):

$$CO_2 + H_2O \Leftrightarrow H_2CO_3$$

Carbonic acid partially dissociates in water to produce acidity [i.e., hydronium ions (H^+); water is omitted for simplicity]:

$$H_2CO_3 \Leftrightarrow H^+ + HCO_3^-$$

Further dissociation occurs in the bicarbonate ion (HCO_3^-) to produce more H^+ and form carbonate ions (CO_3^{2-}):

$$HCO_3^- \Leftrightarrow H^+ + CO_3^{2-}$$

The surface atoms of iron (Fe) in the steel will readily give up electrons to hydronium ions and dissolve into the water in the form of iron ions (Fe^{2+}):

$$Fe \rightarrow Fe^{2+} + 2e^-$$

In obtaining the additional electron, the hydronium ion will form hydrogen gas (H_2), and the reaction is complete.

$$2H^+ + 2e^- \rightarrow H_2$$

When the concentrations of the corrosion products in water (Fe^{2+} and CO_3^{2-} ions) exceed the solubility limit (typically at neutral and alkaline pH), they form solid iron carbonate on the surface of the steel:

$$Fe^{2+} + CO_3^{2-} \Leftrightarrow FeCO_3(s)$$

The layer of iron carbonate can become fairly protective and reduce the rate of underlying steel corrosion by blocking the surface and preventing the corrosive species from reaching it.

The rapid kinetics of mackinawite formation favor it as the initial product of H_2S reactions. However, with time, and as H_2S concentrations increase, mackinawite is less prevalent, and other forms of iron sulfide are seen, such as pyrrhotite. At high H_2S concentrations, pyrite and elemental sulfur are formed. While layers of any iron sulfide will offer some corrosion protection, there is no well-defined relationship between the type of iron sulfide layer and the ensuing rate of corrosion. It is well understood that high H_2S levels accompanied by elemental sulfur can lead to high rates of localized corrosion. However, elemental sulfur is usually associated with the production of natural gas with a high H_2S content. For a crude oil to have similarly high H_2S and elemental sulfur content would be unusual.

Corrosive Effect of Oxygen

Oxygen dissolved in water is undesirable in pipelines because it is highly reactive with iron. Corrosion generally becomes a problem when levels of dissolved oxygen reach those found in aerated surface water (typically about 8 ppm). Smaller amounts of oxygen (below 1 ppm) can become a problem when the oxygen reacts and impairs protective iron carbonate and iron sulfide layers. In general, the water associated with oil production does not contain oxygen, and therefore such high concentrations are seldom observed in shipments of stabilized crude oil transported in pressurized pipelines with controlled air entry points. Oxygen may become elevated when air is introduced into the pipeline inadvertently. Air may be introduced during shutdowns for inspections and repairs. Chronic sources of air ingress, such as during injection of chemicals and in storage tanks holding liquids at atmospheric pressure, are potentially more problematic. Nevertheless, how and why these air entry points would differ from one crude oil shipment to the next in the same pipeline facility are not evident.

Corrosive Effect of Organic Acids

Organic acids with low molecular weights are water soluble and thus present a significant corrosion threat when they are found in settled water that wets the steel surface of crude oil pipelines. A common representative of the family of water-soluble organic acids is acetic acid (CH_3COOH).[1] Other low-molecular-weight organic acids that can lead to corrosion of mild steel include propionic and formic acids. These weak acids create a corrosion scenario similar to the one described for CO_2 attack, with the organic acid taking the place of carbonic acid. Much like carbonic acid, organic acids provide a reservoir of hydronium ions. Their corrosive effect is particularly pronounced at low pH and higher temperatures, when their abundance can increase corrosion rates dramatically. At a higher pH (>6), the corrosive effect of organic acids on mild steel is negligible, regardless of concentrations.

Other organic acids found in crude oil—and notably in bitumen—are compounds with high molecular weight, which are often referred to as naphthenic acids. While these organic acids can be a significant corrosion threat at the high temperatures (>300°C) reached in refineries, they are not a threat to pipe steel because they are not soluble in water but are rather dissolved in the oil phase (Nesic et al. 2012). Accordingly, high-molecular-weight organic acids do not pose a corrosion threat to steel at pipeline temperatures. In some crude oils these acids may even have moderately inhibitive properties (Nesic et al. 2012).

Effect of Microbiologically Influenced Corrosion

The term microbiologically influenced corrosion (MIC) is used to designate the localized corrosion affected by the presence and actions of microorganisms (Little and Lee 2007). The types of damage that can be caused by these microorganisms are not unique, which means that MIC cannot be identified by visual inspection of the damage. Although MIC is discussed here with respect to internal corrosion, it can also contribute to corrosion on the outside of the pipe, as noted later.

Microorganisms that cause MIC are bacteria, archaea, and fungi. Some occur naturally in crude oils, while others may be introduced as contaminants from air, sediment, and water. The temperature range in which these organisms can grow is that in which liquid water can exist, approximately 0°C to 100°C (32°F to 212°F) (Little and Lee 2007). However, individual groups of microorganisms have temperature optima, including sometimes narrow ranges, for growth. The temperature range over which transmission pipelines operate will therefore select for specific microorganisms, but it will not prevent microbial growth.

---

[1] A household name for acetic acid is vinegar, which consists of 2 to 3 percent acetic acid dissolved in water.

For microorganisms to grow and proliferate, they require not only liquid water but also nutrients and electron acceptors for respiration. Accordingly, how microorganisms use water, nutrients, and electron acceptors to grow and how they influence corrosion is explained, and consideration is then given to whether levels of any of these essentials are likely to be affected by diluted bitumen.

Water Availability Microbial growth is limited by the availability of liquid water. Growth is therefore concentrated at oil–water interfaces and in the aqueous phase, including the water in deposits of sludge in pipelines. The volume of water required for microbial growth in hydrocarbon liquids is extremely small (Little and Lee 2007). Because water is a product of the microbial mineralization of organic substrates, microbial mineralization of hydrocarbon can generate the additional water needed for proliferation.

Nutrient Availability Microorganisms need suitable forms of carbon, nitrogen, phosphorus, and sulfur as nutrients (Little and Lee 2007).[2] In oil pipelines, hydrocarbons can be degraded by aerobic or anaerobic processes to yield assimilable carbon. Aerobic degradation of hydrocarbons is faster than anaerobic degradation, with the rate depending on the specific electron acceptors used in the process. In general, the susceptibility of hydrocarbon compounds to degradation can be ranked as follows: linear alkanes, branched alkanes, small aromatics, and cyclic alkanes (Atlas 1981; Das and Chandran 2011; Perry 1984). As the chain length of alkanes increases, bacteria show decreasing ability to degrade these compounds (Walker and Colwell 1975). Some high-molecular-weight polycyclic aromatics may not be degraded at all (Atlas 1981). As a practical matter, however, carbon availability is often not the main constraint for crude oil biodegradation. Both nitrogen and phosphorus are required for microbial growth. Low concentrations of assimilable forms of these elements can limit biodegradation.[3]

Electron Acceptors Microorganisms can use a variety of electron acceptors for respiration. In aerobic respiration, energy is derived when electrons are transferred to oxygen, which is the terminal electron acceptor. In anaerobic respiration, a variety of organic and inorganic compounds may be used as the terminal electron acceptor, including sulfate, nitrate, nitrite, iron (III), manganese (IV), and chromium (VI) (Little and Lee 2007). Anaerobic bacteria can therefore be grouped on the basis of the terminal electron acceptor, such as sulfate-, nitrate-, and metal-reducing bacteria.[4] In petroleum environments, the bacteria most often associated with MIC are sulfate reducers. In anaerobic environments, sulfate reducers produce H_2S when they use the sulfate as an electron acceptor.[5] In addition, many archaea can produce sulfides, and therefore the inclusive term for this group of anaerobes is sulfide-producing prokaryotes (SPP).

SPP-related corrosion of metals used in oil exploration and production has been reported around the world (Mora-Mendoza et al. 2001; Ciaraldi et al. 1999; El-Raghy et al. 1998; Jenneman et al. 1998). A main concern is that these microorganisms produce H_2S. As discussed

---

[2] A representation of the major elements required for a typical microorganism composition is $C_{169}(H_{280}O_{80})N_{30}P_2S$.

[3] Atlas (1981) reported that when a major oil spill occurred in marine and freshwater environments, the supply of carbon was significantly increased and the availability of nitrogen and phosphorus generally became the limiting factor for oil degradation.

[4] There is specificity among anaerobes for particular electron acceptors. Facultative anaerobic bacteria can use oxygen or other electron acceptors. Obligate anaerobic microorganisms cannot tolerate oxygen for growth and survival. Obligate anaerobic bacteria are, however, routinely isolated from oxygenated environments associated with particles and crevices and, most important, are in association with other bacteria that effectively remove oxygen from the immediate vicinity of the anaerobe.

[5] Some anaerobes can also reduce nitrate, sulfite, thiosulfate, or fumarate (Little and Lee 2007).

earlier, H_2S reacts with the iron ions to form a thin layer of the iron sulfide mackinawite that adheres to the steel surface. In the absence of oxygen, and if the concentration of iron ions in the solution is low, this mineral layer will protect the iron in the steel pipe surface from dissolution (Wikjord et al. 1980). However, if oxygen is introduced, the iron sulfide can be converted to an iron oxide and elemental sulfur, which will cause the rate of corrosion to increase substantially for reasons already given.[6] Pipelines operators, therefore, seek to prevent the formation of colonies of SPP and other microorganisms in pipelines through design, operations, maintenance, and chemical means.

Internal Erosion

Solid particles flowing in the crude oil stream can cause erosion of pipe wall, particularly at flow disturbances such as pipe bends. The propensity for erosion is affected by the pipe material; angles of flow impact; flow velocity; and the amount, shape, mass, and hardness of solid particles in the stream. While pipeline erosion is common in the oil production industry, it occurs to a greater extent in production (field) pipelines that contain fluids with high levels of sand and minerals. For example, slurry flow in the pipelines used to move oil sands ore before bitumen extraction can be highly abrasive (Zhang et al. 2012). Because processed crude oils do not contain similarly high concentrations of solids, erosion is not observed to a significant degree in transmission pipelines. Of interest to this study is whether the diluted bitumen delivered to transmission pipelines contains significantly higher concentrations of abrasive solids than do other crude oils and whether it is transported at higher flow rates conducive to erosion.

Assessment of Effects of Diluted Bitumen on Sources of Internal Degradation

The properties of diluted bitumen as they pertain to the identified factors affecting susceptibility to internal degradation from corrosion and erosion are examined next.

Internal Corrosion

Water Wetting and Solids Deposition An important factor in water dropout and wetting is the total water content of the crude oil stream, which is measured by pipeline operators as part of shipment BS&W sampling. As reported earlier, Canadian transmission pipelines require that crude oil shipments not have a BS&W exceeding 0.5 percent. These levels are comparable with, and more often lower than, the levels commonly required by U.S. transmission pipelines. Accordingly, the level of water contained in shipments of diluted bitumen and other crude oils imported by pipeline from Canada will not be higher than that contained in shipments of other crude oils piped in the United States.

Even relatively small amounts of water in crude oil can settle to the pipe bottom. In considering the propensity of water to drop out of the oil stream, important factors include the viscosity, density, and surface tension of the oil and whether it is transported in a flow that is sufficiently turbulent to disperse and suspend water droplets. Shipments of diluted bitumen are

[6] The impact of oxygen on corrosion from anaerobic SPP was examined by Hardy and Bown (1984) by using mild steel and weight loss measurements. Successive aeration–deaeration shifts caused variations in the corrosion rate. The highest corrosion rates were observed during periods of aeration. Hamilton (2003) concluded that oxygen was the terminal electron acceptor in all MIC reactions. In laboratory seawater and fuel incubations, Aktas et al. (2013) demonstrated that there was no biodegradation of hydrocarbon fuels, little sulfate reduction, and no corrosion of carbon steel in the absence of oxygen.

transported at the same pressures and under the same turbulent flow regimes as shipments of other heavy crude oils. The report has demonstrated that diluted bitumen is more viscous than light and medium-density crude oils and is comparable in viscosity with heavy crude oils. A stream of diluted bitumen in turbulent flow should therefore confer the beneficial effect, relative to lighter crude oils, of dispersing and suspending any free water that may exist in the pipeline stream.

A low likelihood that a shipment of diluted bitumen contains water that will settle and wet the bottom of the pipeline will lead to a low likelihood of internal corrosion regardless of the corrosion mechanism or the presence of other contaminants that can contribute to corrosion. All crude oil shipments can carry particles consisting of sand, clay, organic materials, and hydrocarbons that have the potential to drop out of the stream at vulnerable locations in the pipelines. Given its high viscosity, diluted bitumen will suspend the very fine particles that may be contained in its sediment. The solids contained in diluted bitumen are not unusual in quantity or particle size but are within the range of other heavy crude oils, as established in the earlier comparisons. Whether any of the sediments that settle to the pipe bottom threaten underdeposit corrosion will depend critically on associated water, as well as the presence of corrosive gases, acids, and microorganisms.

Corrosive Gases (CO_2, H_2S, and Oxygen) If water does settle and wet the bottom of a pipeline carrying diluted bitumen, such as at low spots and dead legs, consideration of whether shipments of this type of crude oil contain comparatively high levels of dissolved gases that will increase the potential for corrosion is warranted. Data on the CO_2 contained in crude oil lines, including those carrying diluted bitumen, are not readily available. Nevertheless, concentrations can be inferred from the CO_2 levels present at the last point of gas–liquid separation upstream of delivery to the transmission pipeline. As is the case for shipments of other crude oils, various tanks will hold shipments of diluted bitumen before they are delivered to the transmission pipeline facility. This upstream storage, which occurs at atmospheric pressure, will provide the same opportunity for shipments of diluted bitumen as it does for shipments of other crude oils to degas CO_2 before entry to transmission pipelines. Such a comparable upstream environment will produce similarly low CO_2 concentrations and corrosion rates.

Likewise, the quantities of H_2S reported for diluted bitumen (>25 parts per million by weight in liquid phase), as reported in Chapter 3, are lower than in many other crude oils and do not pose a corrosion threat. Even if other corrosive agents are present, the small concentrations of H_2S would contribute little to the corrosive effect, except perhaps to provide a mildly mitigative impact because of the formation of protective iron sulfide layers. The conclusion is that concentrations of dissolved CO_2 and H_2S in diluted bitumen shipments are likely to be low and not greater than those found in other crude oil shipments that are stored and transported similarly.

Transmission pipeline operators restrict air entry points to prevent ingress of oxygen. There are no data on the oxygen content in crude oil pipelines to assess the effectiveness of these restrictions. However, diluted bitumen is transported in the same pipelines as other crude oils, and the number of air entry points can be assumed the same and purposefully restricted. Because crude oils are stored by pipeline operators in large atmospheric pressure tanks, the possibility of air ingress cannot be eliminated, but the ingress will be as low for shipments of diluted bitumen as it is for shipments of other crude oils stored similarly. Even if some free water is assumed to settle to the bottom of a pipeline carrying shipments of diluted bitumen, low levels of oxygen (e.g., below 1 ppm) will not constitute a serious corrosion threat or one that differs from that of a pipeline carrying shipments of other crude oils.

Acids In reviewing the chemistry of diluted bitumen in Chapter 3, no evidence emerged that it contains relatively high levels of low-molecular-weight organic acids such as acetic acid. The high total acid number of diluted bitumen derives from the presence of high-molecular-weight organic acids. These oil-soluble naphthenic acids do not pose an internal corrosion threat under pipeline conditions and may have mitigative effects on corrosion. The acid contained in diluted bitumen is therefore not a threat to internal corrosion of transmission pipelines.

Microbiologically Influenced Corrosion To understand whether diluted bitumen is more likely than other crude oils to cause MIC, it is helpful to examine whether this crude oil is more prone to providing the essential resources required for microbial growth. The water content of diluted bitumen shipments is comparable with that of other crude oil shipments, and diluted bitumen does not have constituents or operating requirements that make pipelines more prone to forming sludge that can harbor microorganisms. The other essential resources that deserve consideration are the availability of critical nutrients (especially carbon and nitrogen) and electron acceptors (especially oxidized sulfur compounds).

While microbial growth requires carbon, it may be limited more by the scarcity of nitrogen in petroleum. As reported earlier, most of the nitrogen in bitumen is bound in carbon structures and unavailable.[7] Lighter oils provide a more readily available source of degradable carbon than do heavy oils, including bitumen. The percentage of low-molecular-weight hydrocarbons is similar in diluted bitumen and other heavy crude oils and lower than the percentages in lighter crude oils. More of the carbon in diluted bitumen is contained in relatively high concentrations of asphaltenes. The molecular weight and structure of asphaltenes vary, but biodegradation of these compounds is an extremely slow process that does not provide a readily available source of carbon for microorganisms (Pineda-Flores and Mesta-Howard 2001).

With regard to the availability of electron acceptors, it was reported earlier that sulfur content is higher in diluted bitumen than in many other crude oils, but the sulfur is not in oxidized forms available for sustained sulfate reduction by SPP. Furthermore, the high sulfur content of bitumen is not correlated with high H_2S content. Most of the sulfur in bitumen is organic sulfur bonded to carbon in heterocyclic rings, which are not easily degraded by microorganisms and thus largely unavailable for metabolism.

In sum, the chemistry of diluted bitumen is not more favorable for microbial growth and activity than is that of other crude oils.

Erosion

The propensity for erosion is affected by the presence and physical properties of the solid particles in the stream, pipe material, angles of particle impact, and impact velocity. Pipe materials and impact angles are the same for diluted bitumen as for other crude oils transported through the same pipelines. Chapter 3 indicated that the velocity of diluted bitumen flowing through pipelines is not higher than the velocity of other crude oil flows. Furthermore, the diluted bitumen imported by pipeline into the United States is produced by using in situ methods that limit the amount of sand, minerals, and other solid particles recovered with the bitumen. The

[7] See Chapter 3.

extracted bitumen is processed to remove water and solids to achieve the requisite BS&W for pipeline transportation to yield solids levels that are similar to those of other crude oil shipments. While limited data are available on the specific physical properties of the solid particles in diluted bitumen, the generally low levels of solids (less than 0.05 percent) do not suggest that shipments of diluted bitumen increase the already low potential for erosion in crude oil transmission pipelines.

Summary of Effects on Sources of Internal Degradation

A review of product properties relevant to internal pipeline corrosion and erosion does not indicate that diluted bitumen is more likely than other crude oils to lead to these failure mechanisms. Shipments of diluted bitumen do not contain unusually high levels of water, sediment, dissolved gases, or other agents that can cause internal corrosion. The organic acids contained in diluted bitumen are not corrosive to steel at pipeline temperatures. Diluted bitumen has density and viscosity levels comparable with those of other crude oils, and it flows through pipelines with velocity and turbulence comparable with other crude oils so as to limit the accumulation of corrosive deposits. On the basis of an examination of the factors influencing microbial growth and activity, shipments of this crude oil do not have a higher likelihood than other crude oil shipments of causing MIC in pipelines. Because it has solids content and flow regimes comparable with those of other crude oils, diluted bitumen does not have a higher to propensity to cause erosion of transmission pipelines.

SOURCES OF EXTERNAL DEGRADATION

External Corrosion

External corrosion of pipelines is usually characterized by uneven metal loss over localized areas covering a few to several hundred square centimeters of the outside steel surface of the pipe (Beavers and Thompson 2006). The electrochemical reactions that are involved usually occur at physically separate locations on the surface. While the anodic reaction is primarily oxidation of iron, the cathodic reaction can be either the hydrogen evolution that occurs in the anaerobic electrolyte trapped under an impermeable pipe coating or the reduction of oxygen under a permeable coating. The water and soluble compounds needed to create the electrolyte can be present in the soil surrounding the buried pipe or in the atmosphere when a pipe is above grade. In addition, a portion of external corrosion incidents involve MIC (Koch et al. 2002; Beavers and Thompson 2006). As discussed later in the section, external corrosion pits can also be sites for the formation and growth of stress corrosion cracks.

External corrosion is thus affected by the pipe material, the corrosivity of the environment, and the performance of coatings and cathodic protection systems. For mild grades of carbon steel commonly used in transmission pipelines, the main concern is the corrosivity of the surrounding environment and the performance of coatings and cathodic protection systems. Although the transported product does not come in contact with either the coating or the environment surrounding the pipeline, it can influence both factors by affecting the operating pressure and temperature of the pipeline.

Because pipeline segments are located below and above ground, they can be exposed to corrosive conditions in the soil and atmosphere. Many factors affect soil corrosivity, including moisture and oxygen content, electrical resistivity, pH, temperature, porosity, microbial activity, and the presence of dissolved salts (Uhlig and Revie 1985; Escalante 1989; Beavers and Thompson 2006). For pipeline segments exposed to the atmosphere, the primary environmental factors influencing corrosion are relative humidity, salt deposition, pollution, and temperature. Operating pressure does not affect these corrosive conditions, but elevated pipeline temperatures and resulting heat flux to the air or soil medium can increase corrosion rates.

Pipeline temperature and pressure can both affect the condition and performance of coatings and cathodic protection systems. As discussed in Chapter 2, coatings provide a barrier between the pipe and the corrosive environment. Coatings can fail in a variety of ways including disbonding from the steel surface. In pipelines using some older coating technologies, such as asphalt mastic systems, elevated temperatures can cause the coating material to deform and potentially reduce surface coverage. Elevated pipeline temperatures can also result in degradation of adhesive properties and increase the diffusion of moisture through the coating in the direction of the steel surface. Moisture diffusion can cause swelling of the coating relative to the steel and bring about increased surface stresses that lead to disbondment. Fluctuating line pressures can cause interfacial strain between the coating and the pipe surface to produce mechanical disbondment of the coating.

An intact coating that prevents contact between the corrosive environment and the steel surface will generally prevent external corrosion. However, all coatings contain some defects that expose the steel. Accordingly, a critical defense against external corrosion is the application of cathodic protection. As discussed in Chapter 2, many cathodic protection systems use an electric current to prevent corrosion where coating coverage is imperfect. Temperature and pressure conditions that cause coating disbondment, therefore, can be more problematic if they impede, or shield, the distribution of cathodic current to sites where steel is exposed. An advantage of modern coating systems, such as fusion bonded epoxy, is that they are compatible with cathodic protection. Shielding is nevertheless a problem observed in some older pipelines wrapped with impermeable tapes and at girth welds treated with field applied shrink sleeves.

Cracking

The potential for transported products to affect the two main forms of cracking in pipelines is reviewed. Consideration is given to the mechanical process of fatigue cracking and forms of environmentally assisted cracking (EAC) that involve interactions of mechanical and corrosion processes.

Fatigue Cracking

Fatigue is characterized by the formation and growth of microscopic cracks on one or both sides of the pipe wall.[8] The first stage in the fatigue process is crack initiation, or nucleation. Nucleated cracks do not cause a fracture, but some may coalesce into a dominant crack as the variable amplitude loading continues. In the second stage, the dominant crack grows in a more stable manner and may eventually reach the thickness of the wall to produce a leak. Alternatively, the dominant crack may grow to a critical length and depth that the pipe steel can

[8] See Beavers and Thompson (2006) for additional description of stress cracking processes.

no longer endure, leading to a rupture. Pipeline internal and external surface conditions caused by factors other than fatigue can lead to initial cracks or enhance crack fatigue crack growth from stress concentration. These factors can include preexisting dents, weld defects, corrosion pits, manufacturing flaws, and damage incurred during pipe transportation to the installation site.

Fatigue cracking can ensue as a result of repetitive, or cyclic, stress loadings on a pipe. Cyclic stresses can be axial (parallel to the axis of pipeline), circumferential (stress in the tangential direction), or radial (perpendicular to the axis). Circumferential, or hoop, stress is usually the most important source of cyclic loadings because the stress created by internal pressure is normally the largest stress on the pipeline.

Because viscous crude oils create more friction, they will require a higher operating pressure than do less viscous crude oils to achieve the same flow rate. In practice, pipeline operators reduce the flow rate when they transport viscous crude oils rather than increase operating pressure. Operating pressure cannot be increased if the pipeline is at the stress limit prescribed in regulations. Thus, only when a pipeline is operating below its stress limit can operating pressure be raised to increase the flow rate of a viscous crude oil.

The pipe segments vulnerable to cracking are those with preexisting flaws or dents and other surface deformities caused by mechanical forces during installation or while in service. Stresses can concentrate at these damage sites, enabling cracks to form and grow after a relatively small number of load cycles, a phenomenon known as low-cycle fatigue.[9] Other locations on the pipe susceptible to stress concentrations include discontinuities at longitudinal and girth welds and at voids formed during pipe manufacturing (Zhang and Cheng 2009).

Pressure cycling is reported to have contributed to fatigue failures in crude oil transmission pipelines. An example is the July 2002 rupture of a 34-inch crude oil pipeline near Cohasset, Minnesota (NTSB 2004). In that incident, the originating crack formed at the seam of the longitudinal weld as a result of vibrations experienced during railroad transportation of the pipe to the installation site. According to the National Transportation Safety Board report, the preexisting crack grew to reach a critical size in response to pressure cycling stresses associated with normal in-service operations.

Environmentally Assisted Cracking

EAC results from the combined action of a corrosive environment and a cyclic or sustained stress loading. In general, EAC emerges in three basic forms: corrosion fatigue, stress corrosion cracking (SCC), and hydrogen-assisted cracking. EAC requires both a sufficient stress and a corrosive environment specific to the metal and thus is rare in crude oil transmission pipelines. However, when EAC failures do occur, they can be destructive; for example, the 2010 failure of a pipeline near Marshall, Michigan, was caused by EAC (NTSB 2012).

Corrosion fatigue cracking arises from a combination of corrosion and the same pressure-related cyclic stresses that produce fatigue cracking. In corrosion fatigue, the stresses sufficient to cause failure can be less severe because of the corrosion reaction and resulting damage. For example, corrosion pits can become stress concentrators that allow normal in-service pressure cycling to cause the formation and growth of cracks in the pit. In the case of pipeline SCC, the same corrosive factors may exist, but the main acting stress is the sustained hoop forces generated by the operating pressure as well as its cycling. The acting stress may also be residual

[9] Conversely, high-cycle fatigue occurs under a low-amplitude loading in which a large number of load cycles is required to produce failure.

in nature, introduced during bending and welding in manufacturing, or it may arise from external soil pressure or differential settlement. The same locations on the pipe that concentrate cyclic stresses, such as dents, scrapes, and other surface discontinuities, can concentrate static stresses. Furthermore, breaks in the surface film may occur at these discontinuities to make the area more prone to electrochemical corrosion.[10]

The factors that create corrosive environments enabling EAC, such as soil properties and the performance of coatings and cathodic protection, have already been discussed with respect to external corrosion. As with external corrosion, the maintenance of coating performance and cathodic protection is critical in controlling EAC (CEPA 2007). In the case of SCC, limiting the introduction of residual stresses during pipe manufacturing, transportation, and installation is also important in reducing susceptibility. Operating pressure is the major in-service source of static hoop stress. Lowering the operating pressure of a pipeline would be expected to reduce the potential for SCC. However, the specific relationship between SCC and hoop stress is not well established. For example, SCC failures have occurred in pipelines experiencing hoop stresses that have varied from 46 to 77 percent of the specified minimum yield strength of the pipeline.[11] Accordingly, adjusting operating pressures as a way to prevent SCC can be difficult.

EAC can be caused or exacerbated by hydrogen-assisted cracking. For example, when sources of hydrogen are present—such as from agents in the crude oil stream (e.g., H_2S) or from external sources (e.g., excessive cathodic protection voltage)—cracking potential may increase. Although hydrogen-assisted cracking is rare in crude oil transmission pipelines, it can occur as a result of the diffusion and concentration of atomic hydrogen at the crack tip or other microstructural trap site in a metal. The ingress of hydrogen into a metal is enhanced in the presence of sulfur species. The trapped hydrogen can cause internal stresses within the metallurgical structure favorable to enhanced cracking or act to reduce local roughness in the region of the crack tip. Hydrogen can also adsorb to the metal surface to reduce surface energy and migrate into the microstructure, thereby reducing interatomic bond strength and providing nucleation sites for cracks. Hydrogen-assisted cracking can occur on the inside or outside of the pipe, depending on the source of the hydrogen and its ability to reach the pipe surface.

Assessment of Effects of Diluted Bitumen on Sources of External Degradation

Because diluted bitumen only contacts the inside of a pipeline, it can contribute to external degradation only indirectly. In the case of external corrosion and EAC, one concern is that elevated operating temperatures can adversely affect the performance of the coating as a barrier to corrosion. The relevant question with respect to both external corrosion and EAC is whether diluted bitumen creates operating temperatures and pressures that are sufficiently different from those of other crude oils to increase coating disbondment. As has been reported, diluted bitumen and other heavy crude oils have similar densities and viscosities and flow through pipelines at the same rate and within comparable pressure and temperature ranges (see Chapter 3, Tables 3-4 and 3-7). For this reason, the likelihood of coating degradation and any associated external damage resulting from the operating parameters of diluted bitumen should be equivalent to that of other crude oils with comparable density and viscosity.

---

[10] At sites of surface damage, such as dents and corrosion pits, stress levels in the circumferential and axial directions are higher than on undamaged portions of the pipe surface.

[11] National Energy Board, notes from January 12, 1996, meeting between National Energy Board SCC Inquiry Panel and Camrose Pipe Company Ltd., Exhibit No. A-58.

Pipelines transporting diluted bitumen and other heavy crude oils should not differ in the stress loadings generated by their transportation because operating pressures are comparable. Other sources of static stress, such as residual stresses from pipe fabrication and installation, would not be affected by the product in the pipeline. Transmission pipelines, therefore, should not experience more stress cracking from transporting diluted bitumen than from transporting other crude oils of similar density and viscosity.

Finally, if the exterior coating of the pipe disbonds, hydrogen may diffuse into the surface metal with a rate of uptake and subsequent potential for embrittlement that will depend on a number of factors, including pH and temperature. However, the operating parameters of diluted bitumen should not increase the potential for coating disbondment. With respect to the interior of the pipeline, the availability of H_2S and free sulfur to form hydrogen in diluted bitumen is relatively low. Thus, transporting diluted bitumen is not likely to increase the potential for hydrogen-assisted cracking.

SOURCES OF MECHANICAL DAMAGE

Mechanical damage to the pipeline and its components can occur as a result of overpressurization or outside forces. Mechanical forces can cause an immediate, and sometimes catastrophic, breach and release or make the pipeline more susceptible to releases by destabilizing support structures and damaging other components such as valves, joints, and other fittings. Damage from mechanical forces can also weaken the resistance of the pipeline to other failure mechanisms. Sites on the pipeline that sustain even light damage, such as scrapes, are vulnerable to corrosion attacks and stress-related cracking. Accordingly, consideration of whether the transportation of diluted bitumen creates an elevated potential for phenomena that can lead to mechanical damage is warranted.

Overpressurization

Various events can generate excessive pressure in a pipeline, including surges, thermal overpressure, column collapse, and human error. If the pipe is already weakened by corrosion, cracking, or deformities from earlier mechanical damage, overpressure events can increase the potential for damage and failure.

Pipeline operators prevent overpressure events through personnel training; standardized procedures; system design; and safety systems such as pressure relief valves, pressure switches, surge tanks, and bypass systems. Nevertheless, excessive pressure in a pipeline can occur as a result of operator error, thermal overpressure, and column separation. A transported fluid that increases the likelihood of any of these outcomes could increase the potential for mechanical damage.

Surge

Any action in a pipeline system that causes a rapid reduction in the velocity of the transported fluid could cause a pressure surge. Transient, high-amplitude pressure waves, or surges, are not normal and can cause mechanical damage to pipes, components (e.g., valves, seals, joints), instrumentation (e.g., meters and gauges), and support structures. Because all crude oils have relatively high bulk modulus (incompressibility), they have a comparable propensity for energy to be transferred in high-pressure waves when events trigger abrupt reductions in flow velocity.

Operator Error

Overpressurization can be caused by direct human error. Unintentional pumping of fluids against a closed valve with coincidental failure of pressure switches, pressure relief valves, and other protective devices is an example of a rare-event overpressurization scenario. Most pipelines are equipped with safeguards such as pressure switches and relief devices to avoid damage from these scenarios. If a transported liquid adds complexity to operational requirements, operator errors could increase.

Column Collapse

Pressure surges can arise from pressure differentials, or slack conditions, in the pipeline. A slack line can occur when the liquid being transported develops a vapor void at a point in the pipeline where line pressure drops below the vapor pressure of the liquid. The void will temporarily restrict the flow of liquid. When the void collapses, a pressure wave comparable with that of a rapid valve closure can be produced. The transformation of the liquid into a vapor phase is known as column separation. To prevent the occurrence of column separation, pipeline operators strive to maintain line pressure above the vapor pressure of the liquid. Locations vulnerable to pressure differentials are elevation peaks and the downstream side of slopes. A liquid that has certain properties, such as a relatively high fraction of hydrocarbons with high vapor pressure, can theoretically increase the potential for column separation.

Thermal Overpressure

A pipe segment that is full of liquid will experience a rapid pressure increase when it is exposed to a heat source and when volume expansion is restricted. Special procedures and thermal relief valves are used to prevent this occurrence in aboveground pipe segments where the flow may be impeded or blocked and the segment may be subsequently exposed to a heat source such as sunlight or fire. Because the chemistry of the trapped fluid determines the amount of pressure increase corresponding to an incremental increase in temperature, some transported liquids could have greater potential for thermal overpressure.

Outside Force Damage

Pipelines can sustain external mechanical damage from both natural forces and human activity. Natural forces include seismic movements and other ground shifts, such as those from landslides and subsidence. Examples of damage from human activity include accidental strikes from vehicles, earth moving activity, and surface loading by farm equipment. Intentional damage to a pipeline, or sabotage, is a potential source of mechanical damage, although it is rare.

There are ways in which the contents of a pipeline can affect or interact with an outside force failure mechanism. One possibility is that a denser, heavier fluid adds weight to a pipe that is free-spanning (i.e., unsupported) or traverses a terrain susceptible to inadequate support. Another possibility is that the heat flux from a fluid transported at an elevated operating temperature reduces the stability of a pipeline in a frost zone. Similar interactions with the outside environment related to pipe vibrations, expansion, and contraction may be postulated as potential sources of mechanical damage.

Assessment of Effects of Diluted Bitumen on Sources of Mechanical Damage

Mechanical damage to the pipeline and its components can occur as a result of outside forces and overpressurization events. Several causes of outside force damage that could be affected to some degree by the properties of the transported liquid have been postulated. The most relevant properties of the transported liquid are density, viscosity, and operating temperatures. However, because these properties are the same for diluted bitumen as many other crude oils, there is no reason to believe their interactions with outside forces will differ. The same conclusion can be reached concerning the potential for mechanical damage due to chemical or physical properties that can affect the propensity for surge, column separation, or thermal expansion. The potential for these sources of mechanical damage should be indistinguishable from that of other crude oils. Diluted bitumen is blended like many other crude oils to remain fully mixed in the pipeline environment and it does not contain a high percentage of light (high vapor pressure) hydrocarbons.

EFFECTS ON OPERATIONS AND MAINTENANCE PROCEDURES

The preceding analysis has consistently found that the properties of diluted bitumen are within the range of other crude oils. These findings do not indicate a need for operations and maintenance (O&M) procedures that are customized to diluted bitumen, nor do they suggest that pipeline operators apply O&M procedures in transporting diluted bitumen that are different from those applied in transporting other crude oils with similar properties. Of course, if operators who traditionally carry only light crude oils do not make appropriate adjustments to line pressure and flow rates when they transport diluted bitumen or any other similarly dense and viscous crude oil, a greater potential for some of the failure mechanisms examined above could result.

Because most pipeline operators transport many varieties of crude oil, they routinely make adjustments to operational parameters to accommodate different crude oil grades. There is no reason to believe that operators fail to make these adjustments when they transport heavy crude oils generally or, more specifically, when they transport diluted bitumen. Nevertheless, to be comprehensive, a search was undertaken for evidence of O&M practices being altered in inadvertent ways that could be detrimental to pipeline integrity.

Operational Procedures

As discussed in Chapter 2, the operation of most pipelines is monitored and controlled by a combination of local and remote systems by using a centralized supervisory control and data acquisition system. Instrumentation at pump stations, tank farms, and other facilities includes sensors, programmable logic controllers, switches, and alarms. Remote systems allow for monitoring and coordination at centralized locations distant from the pipeline facilities. Together, these local and remote capabilities provide protection against abnormal operations—for example, by allowing for the orderly shutdown of pumps and cessation of flow if an alarm condition occurs or if certain operating parameters are violated. Maintaining the integrity of control systems is essential in ensuring safe pipeline operations.

Therefore, whether there are any characteristics of diluted bitumen that could introduce more complexity into or otherwise compromise the satisfactory functioning of pipeline control systems and their components is worth investigating. As previously noted, none of the chemical and physical properties of diluted bitumen suggests that such an effect could be expected, because the properties fall within the range of other crude oils commonly transported by pipeline. Nevertheless, the committee undertook a search of any instances in which operators modified or were advised to modify their standard control and monitoring activities in transporting diluted bitumen. A search of published documents did not reveal any noteworthy reports, special standards, or guidance documentation. In consulting Canadian pipeline operators (see Appendix A), the committee asked whether the transportation of diluted bitumen required changes to set points for safety and control instrumentation. The response was as follows: "There are no differences. Standards and procedures are in place for control that are generic for all crude oil commodities shipped. The standards and procedures are structured to ensure safe operation regardless of the commodity." Likewise, all pipeline operators interviewed in public meetings convened by the committee stated that transporting diluted bitumen did not require different control or monitoring procedures.[12]

In its investigation of the July 25, 2010, EAC-related rupture near Marshall, Michigan, the National Transportation Safety Board found that the control center made repeated errors by increasing the delivery rate of the pipeline under the impression that low-pressure readings caused by the undetected rupture were indicative of slack line conditions caused by column separation (NTSB 2012). The product released in the incident, discussed in Chapter 4, was diluted bitumen. The phenomenon of column separation has already been reviewed, and no evidence that diluted bitumen has properties associated with it was found. Furthermore, the National Transportation Safety Board did not indicate that the shipment of diluted bitumen that was being delivered through the ruptured pipeline had actually experienced column separation or that any of the properties of the shipment had any other specific effect on the actions of the control center.

Maintenance Procedures

As described in Chapter 2, pipeline operators use various methods for preventing, detecting, and mitigating damage in pipelines. Methods for preventing external cracking and corrosion include use of coatings and cathodic protection. Methods for preventing internal corrosion include chemical treatments, flow maintenance, and in-line cleaning. Operators also monitor pipeline conditions by using various inspection tools, probes, and surveys. If transporting diluted bitumen compromises the ability of operators to carry out any of these activities, more adverse conditions could arise and persist and thereby increase the potential for failures.

---

[12] Representatives from Enbridge, Inc., and TransCanada Pipeline Company were invited to make presentations to the committee during its first meeting on July 23, 2012. During the public meeting, the representatives were asked to identify any special operational or maintenance demands associated with transporting diluted bitumen. None was identified. On October 9–10, 2012, committee members convened a public meeting in Edmonton, Alberta, in which representatives of several pipeline companies that transport diluted bitumen were interviewed. In conjunction with the meeting, committee members also visited a transmission pipeline terminal in Fort McMurray, Alberta, where representatives from the pipeline company explained operational and control procedures associated with diluted bitumen transportation. They also responded to questions from committee members. None of the interviews and information obtained from the site visit suggested that operators use different procedures for system control and monitoring when they transport diluted bitumen.

As with other potential issues, the absence of significant differences in the chemical and physical properties of diluted bitumen compared with other heavy crude oils suggests that no changes are required in pipeline maintenance and inspection regimes. Nevertheless, the committee searched for reports of operators experiencing difficulties in carrying out standard maintenance, mitigation, and inspection activities while transporting diluted bitumen. The committee also searched for standards and other guidance documentation alerting operators to issues associated with maintenance and inspection, such as advisories on the use of in-line inspection tools, chemical inhibitors, and coupons and probes for corrosion monitoring. The search did not uncover any issues or added complexities.

In addition, in its questionnaire to Canadian pipeline operators (see Appendix A), the committee asked whether the transportation of diluted bitumen required changes in pipeline cleaning intervals or predictive and preventive maintenance programs. No differences in cleaning intervals or predictive and preventive maintenance programs were reported. Pipeline operators who met with the committee during public meetings (as noted above) were asked similar questions, and all stated that no special maintenance and inspection issues arose in transporting diluted bitumen. They did not report any adverse affects on their ability to carry out their normal maintenance and inspection activities.

Assessment of Effects of Diluted Bitumen on O&M Procedures

As common carriers, operators of transmission pipelines generally have the ability to transport the wide range of crude oil varieties that are in the commercial stream. Accordingly, operations and maintenance procedures are designed to be robust, capable of ensuring operational reliability and safety without the need for significant procedural modifications from one crude oil shipment to the next. The chemical and physical properties of diluted bitumen do not suggest that transporting this product by pipeline requires O&M procedures that differ from those of other crude oils having similar properties. Likewise, inquiries with operators and searches of industry guidelines and advisories did not indicate any specific issues associated with transporting diluted bitumen that would negatively affect operators as they carry out their standard O&M programs, including their corrosion detection and control capabilities.

SUMMARY

The chemical and physical properties of diluted bitumen shipments have been examined to determine whether there are any differences from those of other crude oil shipments that increase the likelihood of pipeline failures from internal degradation, external degradation, or mechanical damage. Any differences that could affect either the frequency or the severity of a failure mechanism or the ability to mitigate it would suggest a difference in failure likelihood. The chemical and physical properties of diluted bitumen shipments were not found to differ in ways that would be expected to create a likelihood of release that is higher for a transmission pipeline transporting diluted bitumen than one transporting other crude oils. An assessment was also made with regard to whether pipeline operators transporting diluted bitumen alter their O&M procedures in ways that can inadvertently make pipelines more prone to the sources of failure. No differences were found in these procedures. The assessment results are summarized in the next chapter.

REFERENCES

Abbreviations

CEPA	Canadian Energy Pipeline Association
NTSB	National Transportation Safety Board

Aktas, D. F., J. S. Lee, B. J. Little, K. E. Duncan, B. M. Perez-Ibarra, and J. M. Suflita. 2013. Effects of Oxygen on Biodegradation of Fuels in a Corroding Environment. *International Biodeterioration and Biodegradation*, Vol. 81, July, pp. 114–126.

Atlas, R. M. 1981. Microbial Degradation of Petroleum Hydrocarbons: An Environmental Perspective. *Microbiological Reviews*, Vol. 45, No. 1, pp. 180–209.

Beavers, J. A., and N. G. Thompson. 2006. External Corrosion of Oil and Natural Gas Pipelines. *ASM Handbook, Vol. 13C, Corrosion: Environments and Industries*, pp. 1015–1025. http://www.asminternational.org/content/ASM/StoreFiles/ACFAB96.pdf.

CEPA. 2007. *Stress Corrosion Cracking: Recommended Practices*, 2nd ed. Calgary, Alberta, Canada.

Ciaraldi, S. W., H. H. Ghazal, T. A. Shadey, H. A. El-Leil, and S. El-Raghy. 1999. Progress in Combating Microbiologically Induced Corrosion in Oil Production. Paper 181. Presented at Corrosion 99, National Association of Corrosion Engineers International, Houston, Tex.

Das, N., and P. Chandran. 2011. Microbial Degradation of Petroleum Hydrocarbon Contaminants: An Overview. SAGE-Hindawi Access to Research, *Biotechnology Research International*, Vol. 2011, Article ID 941810.

DeWaard, C., and D. E. Milliams. 1975. Carbonic Acid Corrosion of Steel. *Corrosion*, Vol. 31, No. 5, pp. 171–181.

El-Raghy, S. M., B. Wood, H. Abuleil, R. Weare, and M. Saleh. 1998. Microbiologically Influenced Corrosion in Mature Oil Fields—A Case Study of El-Morgan Field in the Gulf of Suez. Paper 279. Presented at Corrosion 98, National Association of Corrosion Engineers International, Houston, Tex.

Escalante, E. 1989. Concepts of Underground Corrosion. In *STP 1013: Effects of Soil and Characteristics on Corrosion* (V. Chaker and J. D. Plamer, eds.), American Society for Testing and Materials International, Philadelphia, Pa., pp. 81–94.

Friesen, W. I., S. Perovici, J. C. Donini, and R. W. Revie. 2012. Relative Corrosivities of Crude Oils from Oil Transmission Pipelines. Paper 2012-08. *Proc., 2012 Northern Area Eastern Conference: Corrosivity of Crude Oil Under Pipeline Operating Conditions*, National Association of Corrosion Engineers International, Houston, Tex.

Hamilton, W. A. 2003. Microbiologically Influenced Corrosion as a Model System for the Study of Metal Microbe Interactions: A Unifying Electron Transfer Hypothesis. *Biofouling*, Vol. 19, No. 1, pp. 65–76.

Hardy, J. A., and J. L. Bown. 1984. Corrosion of Mild Steel by Biogenic Sulfide Films Exposed to Air. *Corrosion*, Vol. 40, pp. 650–654.

Jenneman, G. E., P. Wittenbach, J. Thaker, and Y. Wu. 1998. MIC in a Pipe Used for Disposal of Produced Water from a Coal Seam Gas Field. Paper 281. Presented at Corrosion 98, National Association of Corrosion Engineers International, Houston, Tex.

Koch, G. H., M. P. H. Brongers, N. G. Thompson, Y. P. Virmani, and J. H. Payer. 2002. *Corrosion Cost and Prevention Strategies in the United States*. FHWA-RD-01-156. Office of Infrastructure Research and Development, Federal Highway Administration, March.

Little, B. J., and J. S. Lee. 2007. *Microbiologically Influenced Corrosion*. John Wiley and Sons, Hoboken, N.J.

Mora-Mendoza, J. L., R. Garcia-Esquivel, A. A. Padilla-Viveros, L. Martinez, O. F. Cedillo, C. A. Chavez, and M. M. Bautista. 2001. Study of Internal MIC in Pipelines of Sour Gas, Mixed with Formation Waters. Paper 01246. Presented at Corrosion 2001, National Association of Corrosion Engineers International, Houston, Tex.

Mosher, M., B. Crozier, W. Mosher, J. Been, H. Tsaprailis, T. Place, and M. Holm. 2012. Development of Laboratory and Pilot Scale Facilities for the Evaluation of Sludge Corrosivity in Crude Oil Pipelines. Paper 2012-07. *Proc., 2012 Northern Area Eastern Conference: Corrosivity of Crude Oil Under Pipeline Operating Conditions,* National Association of Corrosion Engineers International, Houston, Tex.

Nesic, S., S. Richter, W. Robbins, F. Ayello, P. Ajmera, and S. Yang. 2012. Crude Oil Chemistry on Inhibition of Corrosion and Phase Wetting. Paper 2012-16(c). *Proc., 2012 Northern Area Eastern Conference: Corrosivity of Crude Oil Under Pipeline Operating Conditions,* National Association of Corrosion Engineers International, Houston, Tex.

NTSB. 2004. *Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota, July 4, 2002.* Report NTSB/PAR-04/01. Washington, D.C.

NTSB. 2012. *Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010.* Report NTSB/PAR-12/01. Washington, D.C. http://www.ntsb.gov/doclib/reports/2012/PAR1201.pdf.

Perry, J. J. 1984. Microbial Metabolism of Cyclic Alkanes. In *Petroleum Microbiology* (R. M. Atlas, ed.), Macmillan, New York, pp. 61–98.

Pineda-Flores, G., and A. M. Mesta-Howard. 2001. Petroleum Asphaltenes: Generated Problematic and Possible Biodegradation Mechanisms. *Revista Latinoamericana de Microbiologia*, Vol. 43, No. 3, pp. 143–150.

Uhlig, H. H., and R. W. Revie. 1985. *Corrosion and Corrosion Control: An Introduction to Corrosion Science and Engineering*, 3rd ed. John Wiley and Sons, New York.

Walker, J. D., and R. R. Colwell. 1975. Some Effects of Petroleum on Estuarine and Marine Microorganisms. *Canadian Journal of Microbiology*, Vol. 21, No. 3, pp. 305–313.

Wikjord, A. G., T. E. Rummery, F. E. Doern, and D. G. Owen. 1980. Corrosion and Deposition During the Exposure of Carbon Steel to Hydrogen Sulfide Water Solutions. *Corrosion Science*, Vol. 20, No. 5, pp. 651–671.

Zhang, A. G., and Y. F. Cheng. 2009. Micro-Electrochemical Characterization of Corrosion of Welded X70 Pipeline Steel in Near-Neutral pH Solution. *Corrosion Science*, Vol. 51, No. 8, pp. 1714–1724.

Zhang, J. X., J. C. Fan, Y. J. Xie, and H. C. Wu. 2012. Research on Erosion of Metal Materials for High Pressure Pipelines. *Advanced Materials Research*, Vols. 482–484, pp. 1592–1595.

6

Summary of Results

The study charge and approach and the main points from the preceding chapters are summarized in this chapter. The discussion summaries provide the basis for the findings presented at the end of the chapter.

RECAP OF STUDY CHARGE AND APPROACH

Section 16 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 calls for the Secretary of Transportation to "complete a comprehensive review of hazardous liquid pipeline facility regulations to determine whether the regulations are sufficient to regulate pipeline facilities used for the transportation of diluted bitumen. In conducting the review, the Secretary shall conduct an analysis of whether any increase in the risk of a release exists for pipeline facilities transporting diluted bitumen."[1] A determination of release risk requires an assessment of both the likelihood and the consequences of a release. To inform its assessment of the former, the U.S. Department of Transportation contracted with the National Research Council to convene an expert committee to "analyze whether transportation of diluted bitumen by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils."

As detailed in Chapter 1, the project statement of task calls for a two-phase study, with the conduct of the second phase contingent on the outcome of the first. In the first phase, the study committee was asked to examine whether shipments of diluted bitumen can affect transmission pipelines and their operations so as to increase the likelihood of release when compared with shipments of other crude oils transported by pipeline. In the potential second phase—to be undertaken only if a finding of increased likelihood of release is made in the first—the committee was asked to review federal pipeline safety regulations to determine whether they are sufficient to mitigate an increased likelihood of release from diluted bitumen. If the committee did not find an increased likelihood of release, or the information available was insufficient to make a finding, the committee was expected to prepare a final report documenting the study approach and results.

The committee reviewed data on reported pipeline releases. The review provided insight into the general causes of pipeline failures, but the incident records alone could not be used to determine whether pipelines are more likely to fail when they transport diluted bitumen than when they transport other crude oils. Having examined the general causes of failures, the committee focused on the specific sources of pipeline damage that can be influenced by the transported crude oil. Specifically, it identified the chemical and physical properties of crude oil that can cause or contribute to sources of pipeline failure from damage sustained internally or externally or as a result of mechanical forces.

The committee did not perform its own testing of pipelines or crude oil shipments. Information on the properties of shipments of diluted bitumen and other crude oils was obtained from public websites and assay sheets. Additional information was obtained from a review of

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

government reports and technical literature, queries of oil producers and pipeline operators, field visits, and inferences from secondary sources such as the maximum water and sediment content for pipeline shipments as specified in pipeline tariffs. The committee then compared the relevant properties of shipments of diluted bitumen with the range of properties observed in other crude oil shipments to identify instances in which diluted bitumen fell outside or at an extreme end of the range.

In view of the possibility that some pipeline operators may modify their operating and maintenance practices in transporting diluted bitumen, the committee first posited potential differences and then sought evidence. Operators were questioned about their practices. The committee looked for indications of changes in standard procedures, including corrosion control practices, that could inadvertently make pipelines more susceptible to sources of failure.

MAIN POINTS FROM CHAPTER DISCUSSIONS

Crude Oil Pipeline Transportation in the United States

As described in Chapter 2, the crude oil transmission network in the United States consists of an interconnected set of pipeline systems. Crude oil shipments traveling through the network often move from one pipeline system to another and are sometimes stored at terminals. Most operators of transmission systems are common carriers who do not own the crude oil they transport but provide transportation services for a fee. Few major transmission pipelines are dedicated to transporting specific grades or varieties of crude oil. They usually move multiple batches of crude oil, often provided by different shippers and encompassing a range of chemical and physical properties. Crude oil shipments are treated to meet the quality requirements of the pipeline operator as well as the content and quality demands of the refinery customer.

Pipeline systems traverse different terrains and can vary in specific design features, components, and configurations. The differences require that each operator tailor operating and maintenance strategies to fit the circumstances of its systems in accordance with the federal pipeline safety regulations. Nevertheless, the systems tend to share many of the same basic components and follow similar operating and maintenance procedures. Together, regulatory and industry standards, system connectivity, and economic demands compel both a commonality of practice and a shared capability of handling different crude oils.

Bitumen Properties, Production, and Pipeline Transportation

As discussed in Chapter 3, the bitumen imported into the United States is derived from Canadian oil sands. Canadian bitumen is both mined and recovered in situ using thermally assisted techniques. A large share of the bitumen deposits is too deep for mining, so in situ recovery accounts for an increasing percentage of bitumen production. Because mined bitumen does not generally have qualities suitable for pipeline transportation and refinery feed, it is processed into synthetic crude oil in Canada. Bitumen recovered in situ with thermally assisted methods has lower water and sediment content and is thus better suited to long-distance transportation by pipeline than is mined bitumen. Bitumen imported into the United States is produced in situ through thermally assisted methods rather than by mining.

Like all forms of petroleum, Canadian bitumen is a by-product of decomposed organic materials and thus a mixture of many hydrocarbons. The bitumen contains a relatively large concentration of asphaltenes that contribute to its high density and viscosity. At ambient temperatures, bitumen does not flow and must be diluted for transportation by unheated pipelines. Diluents consist of light oils, including natural gas condensate and light synthetic crude oils created from bitumen. Although the diluents consist of low-molecular-weight hydrocarbons, shipments of diluted bitumen do not contain a higher percentage of these light hydrocarbons than do other crude oil shipments. The dilution process yields a stable and fully mixed product for shipment by pipeline with density and viscosity levels in the range of other crude oils transported by pipeline in the United States.

Shipments of diluted bitumen are piped at operating temperatures, flow rates, and pressure settings typical of crude oils with similar density and viscosity levels. Shipment water and sediment content conforms to the Canadian tariff limits, which are more restrictive than those in U.S. pipeline tariffs. Solids in diluted bitumen shipments are comparable in quantity and size with solids in other crude oil shipments transported by pipeline. While the sulfur in diluted bitumen is at the high end of the range for crude oils, it is bound with hydrocarbons and not a source of corrosive hydrogen sulfide. Diluted bitumen has higher acid content than many other crude oils, but the stable organic acids that raise acidity levels are not corrosive at pipeline temperatures.

Review of Pipeline Incident Data

A logical step in addressing the question of whether shipments of diluted have a greater propensity to cause pipeline releases than shipments of other crude oils is to examine historical release records. The incident statistics can be used to identify the general sources of pipeline failure. However, the information contained in the U.S. and Canadian incident records is insufficient to draw definitive conclusions. As explained in Chapter 4, one reason is that the causal categories in the databases lack the specificity needed to assess the particular ways in which transporting diluted bitumen can affect the susceptibility of pipelines to failure. Another reason is that incident records do not contain information on the types of crude oil transported and the properties of past shipments in the affected pipeline. Because many pipeline releases involve cumulative and time-dependent damage, there is no practical way to trace the transportation history of a damaged pipeline to assess the role played by each type of crude oil and its properties in transport.

Incident reporting systems in Canada and the United States do not have uniform reporting criteria and coverage. Given the relatively small number of pipeline incidents, even minor variations in reporting criteria can lead to significant differences in incident frequencies and causal patterns. Some reporting systems combine incident reports from oil gathering and transmission systems, while others do not. Variation in reporting coverage is problematic because gathering pipelines are fundamentally different from transmission pipelines in design, maintenance, and operations and in the quality and quantity of the liquids they carry.

Effects of Diluted Bitumen on Sources of Pipeline Damage

The chemical and physical properties of diluted bitumen were examined in Chapter 5 to determine whether any differ sufficiently from those of other crude oils to increase the likelihood of pipeline failures from sources of damage internally or externally or from mechanical forces. Any differences that could affect either the frequency or severity of the failure mechanism or the ability to mitigate a potential failure mechanism would suggest a difference in failure likelihood.

No properties were found to differ in any way that may change the likelihood of pipeline damage and failure. An assessment was also made with regard to whether pipeline operators transporting diluted bitumen alter their operating and maintenance procedures in ways that can make pipelines more prone to the causes of failure the procedures are intended to prevent. No differences were found in these procedures. Summaries of the assessments are presented in Box 6-1.

Box 6-1

Summary of Assessments of the Effects of Diluted Bitumen on Causes of Pipeline Damage

Internal Degradation
A review of product properties pertaining to internal pipeline corrosion and erosion did not find that shipments of diluted bitumen are any more likely than shipments of other crude oils to cause these failure mechanisms. Shipments of diluted bitumen do not contain unusually high levels of water, sediment, dissolved gases, or other agents that can cause internal corrosion. The organic acids contained in diluted bitumen are not corrosive to steel at pipeline temperatures. The densities and viscosities of diluted bitumen shipments are within the range of other crude oils, and the velocity and turbulence with which shipments flow through pipelines are comparable and limit the formation of corrosive deposits. On the basis of an examination of the factors that influence microbial growth, diluted bitumen does not have a higher likelihood than other crude oils of causing microbiologically influenced corrosion. Because shipments of diluted bitumen have solids content and flow regimes comparable with those of other crude oil shipments, they do not differ in their propensity to cause erosion of transmission pipelines.

External Degradation
Pipelines can sustain external damage from corrosion and cracking. Because diluted bitumen only contacts the inside of a pipeline, it can contribute to external degradation only as a result of changes in pipeline operational parameters, specifically pipeline temperature and pressure levels. Elevated operating temperatures can increase the likelihood of external corrosion and cracking by causing or contributing to the degradation of protective coatings and by accelerating rates of certain degradation mechanisms. Elevated operating pressures can cause stress loadings and concentrations that lead to stress-related cracking, particularly at sites of corrosion and preexisting damage. Because the densities and viscosities of diluted bitumen are comparable with those of other crude oils, it is transported at comparable operating pressures and temperatures. For this reason, the likelihood of temperature- and pressure-related effects is indistinguishable for diluted bitumen and other crude oils of similar density and viscosity. Consequently, diluted bitumen will not create a higher propensity for external corrosion and cracking in transmission pipelines.

(*continued*)

Box 6-1 (*continued*)

Mechanical Damage
Mechanical damage to the pipeline and its components can occur as a result of overpressurization or outside forces. Mechanical forces can cause an immediate release or make the pipeline more susceptible to release by destabilizing support structures; damaging other components such as valves and joints; and weakening resistance to other failure mechanisms, such as corrosion attack. The study examined several possible causes of an increased potential for mechanical damage due to the properties of the transported liquid, including the potential for shipments of diluted bitumen to cause pressure surges or to interact with outside forces that can cause damage in pipelines. None of the properties or operating parameters of diluted bitumen shipments was found to be sufficiently different from those of other crude oils to suggest a higher potential to cause or exacerbate mechanical damage in pipelines.

Effects on Operations and Maintenance Procedures
As common carriers, operators of transmission pipelines generally have the ability to transport the wide range of crude oil varieties that are in the commercial stream. Accordingly, operations and maintenance procedures are designed to be robust, capable of ensuring operational reliability and safety without the need for procedural modifications from one crude oil shipment to the next. The chemical and physical properties of diluted bitumen shipments do not suggest that transporting them by pipeline requires operations and maintenance procedures that differ from those of other crude oil shipments having similar properties. Likewise, inquiries with operators and searches of industry guidelines and advisories did not indicate any specific issues associated with transporting diluted bitumen that would negatively affect operators as they carry out their standard operations and maintenance programs, including their corrosion detection and control capabilities.

STUDY RESULTS

Central Findings

The committee does not find any causes of pipeline failure unique to the transportation of diluted bitumen. Furthermore, the committee does not find evidence of chemical or physical properties of diluted bitumen that are outside the range of other crude oils or any other aspect of its transportation by transmission pipeline that would make diluted bitumen more likely than other crude oils to cause releases.

Specific Findings

Diluted bitumen does not have unique or extreme properties that make it more likely than other crude oils to cause internal damage to transmission pipelines from corrosion or erosion. Diluted bitumen has density and viscosity ranges comparable with those of other crude oils. It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and operating temperature. The amount and size of solid particles in diluted bitumen are within the range of other crude oils so as not to create an increased propensity for deposition or erosion. Shipments of diluted bitumen do not contain higher concentrations of water, sediment, dissolved gases, or other agents that cause or exacerbate internal corrosion, including microbiologically influenced corrosion. The organic acids in diluted bitumen are not corrosive to steel at pipeline operating temperatures.

Diluted bitumen does not have properties that make it more likely than other crude oils to cause damage to transmission pipelines from external corrosion and cracking or from mechanical forces. The contents of a pipeline can contribute to external corrosion and cracking by causing or necessitating operations that raise the temperature of a pipeline, produce higher internal pressures, or cause more fluctuation in pressure. There is no evidence that operating temperatures and pressures are higher or more likely to fluctuate when pipelines transport diluted bitumen than when they transport other crude oils of similar density and viscosity. Furthermore, the transportation of diluted bitumen does not differ from that of other crude oils in ways that can lead to conditions that cause mechanical damage to pipelines.

Pipeline operating and maintenance practices are the same for shipments of diluted bitumen and shipments of other crude oils. Operating and maintenance practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change such practices while transporting diluted bitumen.

These study results do not suggest that diluted bitumen will experience pipeline releases at a rate that is higher than its proportion of the crude oil stream. Future pipeline releases can be expected to occur, and some will involve diluted bitumen. All pipeline releases can be consequential. As explained at the outset of this report, the committee was not asked or constituted to study whether pipeline releases of diluted bitumen and other crude oils differ in their consequences or to determine whether such a study is warranted. Accordingly, the report does not address these questions and should not be construed as having answered them.

APPENDIX A

Questionnaire to Pipeline Operators on Transporting Diluted Bitumen

The following questions were developed by the committee and given to the Canadian Energy Pipeline Association (CEPA) in January 2013. CEPA distributed the questionnaire to member pipeline companies and returned the results in March 2013. Operator responses are indicated in bold text.[1]

1. Please provide the following information:
   a. Total amount of transmission crude oil pipeline mileage: **Approximately 24,000**
   b. Mileage dedicated to dilbit service: **Approximately 890**
   c. Mileage in batch service: **Approximately 20,530**
   d. Percentage of barrels transported per day consisting of diluted bitumen:
      Operator A: 82 percent
      Operator B: 15 to 65 percent
      Operator C: 65 percent
      Operator D: 65 percent
      Operator E: 28 percent dilbit; 3 percent synbit

2. Please provide the following parameters on the properties of diluted bitumen measured at points of custody transfer or in-line (as appropriate and available):
   Table A-1 includes information gathered on a best-effort basis. One operator also reported some data for synbit, and these data were included for reference. In addition, H_2S data for a large number of crude oils are available from a study performed by Omnicon supported by several pipeline operators. These data were collected by using ASTM D5263 and have been included below for reference (see Figure A-1).

3. How often (e.g., percentage of barrels transported) is specified basic water and sediment (BS&W) exceeded at diluted bitumen initial custody transfer?
   For dilbit batches, between 0 and 0.6 percent of the barrels transported exceeded specified limits.

4. Is BS&W exceeded more often for diluted bitumen compared with other crude oils transported?
   Three operators reported no differences. In two cases, dilbit batches did exceed specified limits more often than other crude oils by a small margin of between 0.1 and 0.3 percent.

[1] API = American Petroleum Institute; CO_2 = carbon dioxide; H_2S = hydrogen sulfide; KOH = potassium hydroxide; O_2 = oxygen; ppm = parts per million; ppmw = parts per million by weight; psi = pounds per square inch; TAN = total acid number.

TABLE A-1 Operator Responses to Question 2

Parameter	Operator	Average	Normal Range	Extreme High
Total BS&W (volume percentage)	A	0.35	0.25 to 0.40	0.5
	B	0.21	0.05 to 0.36	0.36
	C	0.18	0.11 to 0.25	0.5
	D	0.26	0.05 to 0.5	0.5
	E (dilbit)	0.28	0.1 to 0.38	0.5
	E (synbit)	0.31	0.28 to 0.34	0.5
Water share of BS&W	C	50 percent	40 to 60 percent	100 percent
Sediment share of BS&W	C	50 percent	40 to 60 percent	100 percent
Solid content (ppmw)	B		0 to 0.01	
Solids particle size (microns)	Not routinely measured in crude oil			
H_2S (ppmw)	B	6.77	0.1 to 11.1	11.1
	C	<0.5		10
	E	<0.5	<0.5	
Carbon dioxide (ppm)	Not routinely measured in crude oil			
Oxygen (ppm)	Not routinely measured in crude oil			
Sulfur (weight percentage)	A	3.8	3.62 to 3.85	
	B	3.3	2.45 to 4.76	4.8
	C	3.8	3.79 to 3.89	4.0
	D	3.7	3.0 to 4.1	4.1
	E (dilbit)	4.0	3.46 to 4.97	5.2
	E (synbit)	3.1	3.04 to 3.21	3.5
API gravity	A	21.5	19.0 to 23.1	
	B	20.6	19.3 to 21.3	
	C	22.1	21.4 to 22.2	
	D	21	19.0 to 23.3	
	E (dilbit)	21.5	20.3 t 21.9	
	E (synbit)	19.8	19.5 to 20.1	
Reid vapor pressure (psi)	B	5.1	2.54 to 7.58	7.58
	C	7		
	D	8	3 to 11.8	11.8
	E (dilbit)	7.3	5.85 to 7.79	14.9
	E (synbit)	3.1	2.4 to 3.0	14.9
TAN (mg KOH/g)	A	1	0.85 to 1.05	
	B	1.6	1.0 to 2.17	3.34
	C	1.6	1.52 to 1.64	1.82
	D	1.06	0.6 to 1.9	1.9
	E (dilbit)	1.3	0.92 to 2.49	3.75
	E (synbit)	1.6	1.4 to 2.22	2.5

(continued)

TABLE A-1 *(continued)* **Operator Responses to Question 2**

Parameter	Operator	Average	Normal Range	Extreme High
Transport temperature (°C), transmission pipelines	A	30	26 to 34	40
	B	10 (winter); 22 (summer)	4 to 29	32
	C	15	5 to 35	50
	D	27	13 to 43	43
	E	17	9.5 to 22.7	25.4
Flow rate (ft/s) in transmission pipelines	A	4	2.0 to 6.0	
	B	6.56	4.5 to 7.2	8.2
	C	2.5	0.5 to 4.7	5.0
	D	6.7	4.8 to 8.2	8.2
	E	3.63	3.63	4.04
Pressure (psi) in transmission pipelines	A	930	700 to 1,200	1,300
	B	600	43.5 to 1,160	1,440
	C	500	175 to 1,350	1,440
	D	430	50 to 1,440	1,440
	E	750	750	1,095

5. Do tank storage methods for diluted bitumen differ from those of other crudes to possibly affect level of O_2, CO_2, water, and other contaminants?
   No, the storage method is the same as for all crude oil commodities. Dilbits are generally stored in their own commodity group to reduce downgrading.

6. Note any differences in set points for safety and control instrumentation for pipelines in diluted bitumen service as opposed to lines in other service:
   There are no differences. Standards and procedures are in place for control that are generic for all crude oil commodities shipped. The standards and procedures are structured to ensure safe operation regardless of the commodity.

7. Note any differences in the frequency of shutdowns, low-flow, and non-turbulent flow conditions while in diluted bitumen service:
   There are typically no differences that are related to dilbit service. One operator reported a small increase of shutdown frequency due to BS&W exceedance.

8. Note any special surge control equipment and/or vibration monitors on pipelines that carry diluted bitumen:
   No special equipment has been installed specifically to accommodate dilbit.

9. Are drag reducing agents used for diluted bitumen transportation?
   If so, does their use differ (more or less?) compared with other crude types?
   Three of five operators are currently not using drag-reducing agents for dilbit transportation. The use of drag-reducing agents is not specific to dilbit transportation. Their use is based on the operational requirements of a particular pipeline segment and throughput required.

10. Do pipelines undergo more pressure cycling when in diluted bitumen service?
The operating philosophy and function of a pipeline drive pressure cycling, not the type of product transported. Batching between heavy and light products in the same pipeline may cause additional cycling; however, this is related to the switch in products rather than the products themselves. One operator reported that dilbit service lines cycle less frequently than those in conventional crude oil service.

11. Are pressure cycles measured and monitored for use in fatigue calculations?
Three of five operators currently monitor and use pressure cycles in fatigue calculations, and one operator is planning to complete this activity in the future. One operator does not currently complete this activity.

12. Are corrosion inhibitors, including biocides, used for diluted bitumen shipments? If so, do quantities differ from those used for other crude types?
Three of the operators use chemical treatment for bacteria or corrosion control in at least some of their pipelines. Chemical treatment requirement is determined by the flow conditions and pipeline condition. When such treatments are required, the volume and quantities are the same as for other crude oil pipelines.

13. Is cleaning required at different intervals for pipelines in diluted bitumen service versus pipelines in other service?
The requirement for a cleaning program and cleaning intervals are primarily determined by consideration of flow conditions and the potential for water and sediment deposition for all crude oil types. No differences in cleaning intervals were reported by any operator.

14. Is the debris from pig cleaning analyzed?
If so, note any differences in composition for pipelines in diluted bitumen service?
Four of five operators complete testing of debris from pig cleaning, and no differences in composition have been reported for pipelines in dilbit service versus other heavy commodity pipelines. For pipelines in batch service with multiple products including dilbit, it is not possible to differentiate the sediment collected.

15. Is there any evidence from in-line inspection and/or other corrosion monitoring activities indicating unusual or unexpected corrosion locations for lines in diluted bitumen service?
Corrosion in heavy-oil pipelines can occur in areas where water or sediment accumulates—including low areas, critical inclines, and overbends. The latter location was unexpected when it was identified in 2005, but this does not appear to be unique to dilbit pipelines and is common to heavy commodities in general. No unusual or unexpected corrosion locations have been attributed to dilbit service.

16. Note any difference in clogging or wear of equipment, such as pumps, for lines in diluted bitumen service:
No clogging or unusual wear has been identified for lines in dilbit service.

17. Note any differences in predictive/preventive maintenance practices for lines in dilbit service:
    No special predictive or preventive maintenance practices are required for dilbit pipelines.

18. More generally, do you have integrity management programs specific to lines in dilbit service?
    No, dilbit lines are incorporated into overall integrity management programs. In more than 25 years of diluted bitumen service on some pipelines, no unique or more severe threats specific to diluted bitumen service have been observed.

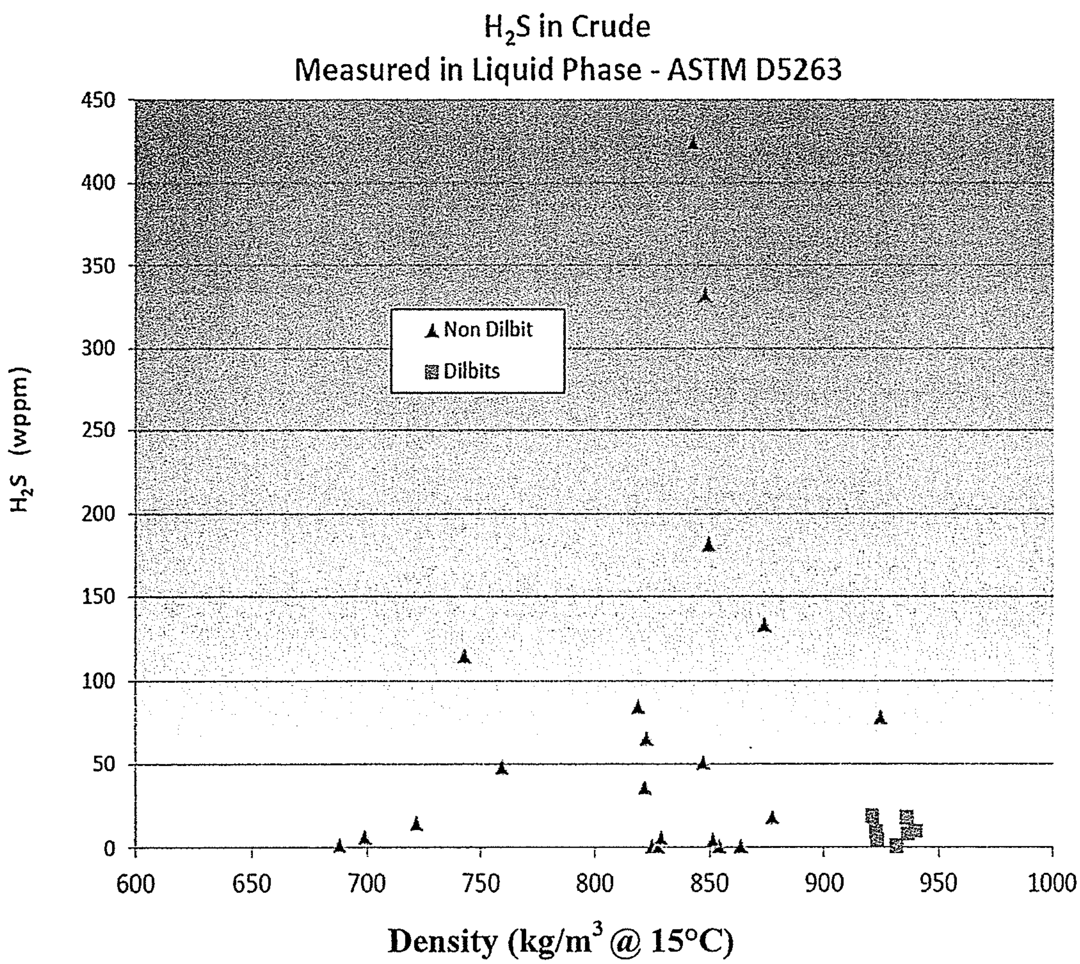

FIGURE A-1 Supplemental information on H_2S content.

APPENDIX B

Federal Pipeline Safety Regulatory Framework

ORIGINS OF HAZARDOUS LIQUIDS PIPELINE SAFETY REGULATION

The Hazardous Liquid Pipeline Safety Act (HLPSA) of 1979, as amended, provides the statutory authority for the U.S. Department of Transportation (USDOT) to establish regulatory standards for the transportation of hazardous liquid by pipelines, including those transporting crude oil.[1] Within the department, authority to carry out the act is delegated to the Pipeline and Hazardous Materials Safety Administration (PHMSA), which implements its authority through the Office of Pipeline Safety (OPS). OPS promulgates rules governing the design, construction, testing, inspection, maintenance, and operations of hazardous liquid pipelines. The regulations are intended to establish minimum safety standards applicable to all hazardous liquid pipeline facilities, thereby setting a safety floor that all operators must meet across the spectrum of pipeline systems. The regulations cover pipelines that transport crude as well as refined products.

A review of past OPS rulemaking notices reveals that as the regulatory program evolved and matured, USDOT and Congress began to question whether the regulatory program was having sufficient effect in reducing the risk of transporting hazardous liquid by pipeline. A central concern was that individual pipeline operators could be complying with each of the actions prescribed in the federal rules in a procedural, or "checklist," manner without really knowing whether these actions were collectively producing the desired safety assurance. Because pipeline facilities vary in their designs, construction, environments, and operating histories, specific safety assurance methods—including those not prescribed in federal rules—might be more suitable for one facility than for another. Moreover, OPS had long been concerned that it could not identify all facility-specific risks, which made a strictly prescriptive approach to safety regulation impractical. The changes made in response to these concerns have led to changes in the role of OPS and to new expectations for safety assurance by the pipeline industry.

PRESCRIPTIVE AND PERFORMANCE-BASED STANDARDS

After several major pipeline releases during the late 1980s and early 1990s, OPS started experimenting with other regulatory approaches to accompany its rules, which prescribed such specific actions as maintaining operating pressure at levels not to exceed 72 percent of specified minimum yield strength (SMYS).[2] The agency sponsored a series of demonstration projects that gave operators the incentive and flexibility to tailor their safety assurance methods to their specific circumstances. OPS reasoned that because pipeline operators have the most comprehensive and detailed knowledge of their systems, they are in the best position to devise their safety assurance programs, as long as they are given the motivation, tools, and regulatory flexibility to make effective choices.[3]

---

[1] Rulemaking to begin implementation of HLPSA began in 1981 (*Federal Register*, Vol. 46, No. 143, July 27, 1981) and can be found at http://phmsa.dot.gov/staticfiles/PHMSA/hrmpdfs/1981%20hist%20rulemakings/46%20FR%2038357.pdf.
[2] §195.406.
[3] See *Federal Register*, Vol. 65, No. 237, Dec. 8, 2000.

In 2000, OPS issued a landmark rulemaking titled Pipeline Integrity Management in High Consequence Areas.[4] Rather than prescribing specific operations and maintenance procedures, new rules laid out the key steps to be followed in developing and implementing a rationalized integrity management program based on principles of risk management. The regulations defined the core elements of the required program, such as the development of a written plan explaining how risks are to be identified; the logic used in choosing the tools, methods, and schedules employed for detecting and assessing risks; and the timetable for completing risk assessments and correcting deficiencies. The rules were written in performance-based language that does not tell operators exactly how they must conduct the risk assessments or precisely how they must act to mitigate identified risks. For example, if internal corrosion is identified as a threat in a particular pipeline segment, the operator is held responsible for selecting the best means to mitigate it—by using corrosion inhibitors, increasing the frequency of line cleaning, shortening inspection intervals, or selecting other defensible options.

Although performance-based rules have the advantage of allowing customized responses to specific circumstances, they can at times lack the clarity of a specific measure prescribed in rules applicable to all.[5] Accordingly, OPS has retained many of its prescriptive rules and continues to adopt new ones, depending on the safety concern. Box B-1 outlines the basic set of rules governing the transportation of hazardous liquids by pipeline, as contained in the Code of Federal Regulations, Title 49, Part 195. Examples of prescriptive rules, in addition to the aforementioned standard for maximum operating pressure, are those concerning pipeline design and construction features, such as the requirement for shutoff valves located at each side of a water crossing.[6] Nevertheless, in instances where alternatives to prescribed measures have safety merit, the operator can seek a waiver, or special permit, from OPS by demonstrating that the alternative measures will yield the same or higher levels of safety than the prescribed ones.[7]

An example of a special permit application is the original plan of TransCanada Corporation to construct the Keystone XL pipeline. When the pipeline was first proposed in 2008, the company petitioned OPS to allow for maximum operating pressures of 80 percent of SMYS. OPS agreed to the special permit conditioned on TransCanada Corporation implementing 57 measures not currently delineated in the regulations and on adding a degree of rigor not currently required. The conditions covered, among other things, quality control checks during the manufacture and coating of the pipe, tighter valve spacing, remote control valves, monitoring and control of operating temperatures, more frequent pig cleaning, and specific limits on the levels of water and sediment contained in the products transported. Although TransCanada Corporation eventually withdrew the special permit application, it agreed to comply with the 57 conditions as part of its separate presidential application to build and operate a pipeline that crosses a national border.[8]

---

[4] See *Federal Register*, Vol. 65, No. 237, Dec. 8, 2000.

[5] For example, the National Transportation Safety Board recently urged PHMSA to revise the integrity management–high consequence area rule to better define when an assessment of environmental cracks must be performed, acceptable engineering methods for such assessments, and specific treatments that must be applied when cracks are found. http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=4c83a26cf5fcbaf90e350dddcff30166&rgn=div8&view=text&node=49:3.1.1.1.11.6.22.28&idno=49.

[6] §195.260.

[7] These are general regulations also pertaining to natural gas pipelines and are thus contained in 49 CFR Part 190.

[8] In 2008, TransCanada Corporation proposed the addition of a new hazardous liquid transmission pipeline, called the Keystone XL, which would originate in Alberta and terminate in Steele City, Nebraska. Because the pipeline crossed the U.S. border, it required presidential approval. Public Law 112-78 required the president to act on the application within 60 days of the law's enactment on December 23, 2011. In early 2012, President Barack Obama denied the application, citing a review by the U.S. Department of State that expressed the need for more information to consider relevant environmental issues and the

Finally, in addition to having special permit authority, OPS has broad authority in the name of public safety to demand that pipeline operators take certain actions not specifically called for in regulations. For example, if the agency discovers a hazardous condition, it can issue orders requiring operators to take certain responsive or precautionary measures.[9] On discovering a condition that may be of concern to multiple pipelines, OPS can issue advisory bulletins that notify operators about the condition and how it should be corrected.

SUPPORTIVE PROGRAMS

The emphasis on risk- and performance-based standards has not only affected OPS rulemaking activity but also changed other aspects of its safety oversight program. Where it does not prescribe specific safety actions or practices, OPS seeks to ensure that operators are in compliance with the performance-oriented demands outlined in the regulations. Aided by its inspection and enforcement capabilities, OPS will verify that pipeline operators are developing and implementing risk management programs that have a rigorous and technically sound basis. A checklist compliance inspection approach is not considered adequate. Inspecting for compliance under these circumstances requires an approach more akin to a quality assurance audit to ensure that operators are following a well-defined set of actions. In addition, the advent of performance-based regulations has meant that OPS safety researchers now have responsibility for providing technical guidance to aid operators in developing rigorous risk management programs, including development of the requisite analytic tools.

About half of the 200-person OPS staff is responsible for inspecting pipeline facilities, with assistance from more than 300 state inspectors. Inspectors are authorized to review the manual for operations and maintenance required of each operator. Inspectors also review records documenting the evaluations that have been performed to identify and prioritize risk factors, devise integrity management strategies, and prioritize the preventive and mitigative measures. If OPS has reason to believe that a specific risk factor is escaping the scrutiny of a pipeline operator, it can review company records to determine whether and how the risk is being treated. As described in Chapter 4, PHMSA also requires operators to report incidents involving releases from pipelines. The agency uses the reports to guide its regulatory, inspection, and enforcement priorities.

Through its research and engineering capacity, OPS can assist pipeline operators in complying with both prescriptive and performance-based rules. In 2012, the agency funded about $7 million in research, with most projects conducted in collaboration with industry through cooperative programs such as the Pipeline Research Council International, Inc. Much of the research is designed to help operators comply with regulatory demands; for example, by developing tools and methodologies to detect and map pipeline leaks, locate and diagnose faults in cathodic protection systems, inspect lines that cannot be pigged, and conduct risk analyses. Research projects are also designed to provide technical support for industry standard-setting activities; for example, by evaluating new test methods being considered by standards development committees.

---

consequences of the project on energy security, the economy, and foreign policy (*Federal Register*, Vol. 77, No. 23, Feb. 3, 2012, p. 5614).

[9] 49 CFR §190.

Box B-1

Summary of Coverage of Federal Hazardous Liquid Pipeline Safety Regulations

Title 49, Part 195—Transportation of Hazardous Liquids by Pipeline

Subpart A—General

§195.0 to §195.12	Regulation coverage, definitions, incorporations by reference of consensus standards, and compliance responsibility.

Subpart B—Reporting

§195.48 to §195.64	Includes reporting requirements for accidents and safety-related conditions as well as requirements for operators to provide assistance during investigations.

Subpart C—Design

§195.100 to §195.134	Includes pipe and component design requirements governing design temperature, internal design pressure, external pressure and loads, valves and fittings, closures and connections, and station pipe and breakout tanks.

Subpart D—Construction

§195.200 to §195.266	Includes construction-related requirements governing material inspection, transportation of pipe, location of pipe, installation and coverage of pipe, welding procedures and welder qualifications, weld testing and inspection, valve location, pumping stations, and crossings of railroads and highways.

Subpart E—Pressure Testing

§195.300 to §195.310	Includes requirements governing pressure testing of pipe, components, tie-ins, and breakout tanks. Also contains requirements for risk-based alternatives to pressure testing of older pipelines.

Subpart F—Operations and Maintenance

§195.400 to §195.452	Includes requirements for an operations, maintenance, and emergency response manual; maximum operating pressure; inspections of breakout tanks and rights-of-way; valve maintenance; pipe repairs; line markers and signs; public awareness and damage prevention programs; leak detection and control room management; and integrity management in high-consequence areas.

(*continued*)

Box B-1 (*continued*)

Subpart G—Qualification of Pipeline Personnel

§195.501 to §195.509	Requirements for qualification programs and record keeping.

Subpart H—Corrosion Control

§195.551 to §195.589	Includes regulations on coatings for external corrosion control, coating inspection, cathodic protection and test leads, inspection of exposed pipe, protections from internal corrosion, protections against atmospheric corrosion, and assessment of corroded pipe.
Appendix A	Delineates federal and state jurisdiction.
Appendix B	Risk-based alternative to pressure testing older pipelines.
Appendix C	Guidance for integrity management program implementation.

APPENDIX C

Data-Gathering Sessions

Committee for a Study of Pipeline Transportation of Diluted Bitumen

First Meeting
July 23–24, 2012
Washington, D.C.

July 23

9:45 a.m. Briefing by study sponsor, Pipeline and Hazardous Materials Safety Administration (PHMSA)
Linda Daugherty, Deputy Associate Administrator for Policy and Programs
Alan Mayberry, Deputy Associate Administrator of Field Operations
Jeffery Gilliam, Senior Engineer and Project Manager

- Origins and scope of study
- Overview of PHMSA's regulatory program
- Agency data sources and technical reports
- Additional background

11:30 a.m. Overview of relevant industry consensus standards and state of the practice in detecting, preventing, and mitigating internal corrosion of oil pipelines
Oliver Moghissi, President, National Association of Corrosion Engineers (NACE), and Director, DNV Columbus, Inc

1:00 p.m. Alberta Innovates report, *Comparison of Corrosivity of Dilbit and Conventional Crude*
John Zhou, Alberta Innovates Energy and Environment Solutions
Harry Tsaprailis, Alberta Innovates Technology Futures

1:45 p.m. Industry associations
Peter Lidiak, Director, Pipelines, American Petroleum Institute

2:30 p.m. Operator experiences—Enbridge Pipelines, Inc.
Scott Ironside, Director, Integrity Programs

3:30 p.m. Operator experiences—TransCanada Corporation
Bruce Dupuis, Program Manager, Liquid Pipeline Integrity
Jenny Been, Corrosion Specialist, Pipe Integrity

4:15 p.m. Concerns raised in Natural Resources Defense Council (NRDC) report
Anthony Swift, Attorney, International Program, NRDC

5:00 p.m. General discussion

5:45 Adjournment

July 24

9:35 a.m. National Energy Board (NEB)—Overview of Regulatory, Data, and Technical Activities
Iain Colquhoun, Chief Engineer, NEB

10:15 a.m. Standard and Non-Standard Methodologies to Evaluate Crude Oil Corrosivity Under Pipeline Operating Conditions
Sankara Papavinasam, Senior Research Scientist, CanmetMATERIALS

11:00 a.m. Public forum

12:15 p.m. Adjournment

Subcommittee Meeting
October 9, 2012
Edmonton, Alberta

8:40 a.m. Introductions: Enbridge Pipelines, Inc.; TransCanada; Inter Pipeline; Kinder Morgan; Crude Quality, Inc.

9:30 a.m. Experience with diluted bitumen quality and cleanliness when entering the pipeline system

10:45 a.m. Pipeline control and operations: diluted bitumen versus conventional crude oils

12:30 p.m. Integrity knowledge of pipelines
Findings from inspecting pipelines in high consequence areas for anomalies

1:30 p.m. Other presentations

3:00 p.m. Tour of Natural Resources Canada, CanmetENERGY laboratory

Second Committee Meeting
October 23, 2012
Washington, D.C.

10:50 a.m.	Overview of pipeline equipment, field operations, control center, leak detection, maintenance, regulation, and economics Thomas Miesner, Pipeline Knowledge and Development
1:30 p.m.	Background on crude oils and diluted bitumen Harry Giles, Executive Director, Crude Oil Quality Association Randy Segato, Suncor Energy Andre Lemieux, Canadian Crude Quality Technical Association
2:30 p.m.	Diluted bitumen: chemical and physical properties Heather Dettman, Natural Resources Canada, CanmetENERGY
3:30 p.m.	Evidence from pipeline incident reporting systems PHMSA data: Jeffery Gilliam and Blaine Keener, PHMSA Pipeline Performance Tracking System: Peter Lidiak, American Petroleum Institute, and Cheryl Trench, Allegro Energy Consulting
4:30 p.m.	Overview of PHMSA supplemental regulatory authorities to mitigate risk Jeffery Gilliam, PHMSA
5:00 p.m.	Adjournment

Third Committee Meeting
January 31, 2013
Washington, D.C.

10:30 a.m.	Summary of NACE conference proceedings on heavy oil and corrosion Sankara Papavinasam, Senior Research Scientist, Natural Resources Canada, CanmetMATERIALS
11:15 a.m.	Operational experience transporting heavy crude oils by pipeline in California Art Diefenbach, Vice President of Engineering, Westpac Energy
1:00 p.m.	Overview of federal hazardous liquid pipeline regulatory approach Jeffrey Wiese and Jeffery Gilliam, PHMSA
2:00 p.m.	Changing patterns of crude oil supply and demand Geoffrey Houlton, Senior Director, Global Crude Oil Market Analysis, IHS
3:00 p.m.	Adjournment

Study Committee Biographical Information

Mark A. Barteau, *Chair,* is DTE Energy Professor of Advanced Energy Research, Professor of Chemical Engineering, and Director of the University of Michigan Energy Institute. Before accepting his appointments at the University of Michigan in 2012, he retired from the University of Delaware as Senior Vice Provost for Research and Strategic Initiatives and Robert L. Pigford Chair in Chemical Engineering. He was a National Science Foundation Postdoctoral Fellow at the Technische Universität München before joining the University of Delaware as Assistant Professor of Chemical Engineering and Associate Director of the Center for Catalytic Science and Technology in 1982. He became Director of the Center for Catalytic Science and Technology in 1996. He has held visiting appointments at the University of Pennsylvania and the University of Auckland, New Zealand. His research in surface chemistry and heterogeneous catalysis has been recognized with numerous awards, including the International Catalysis Award. He was the founding director of the University of Delaware Energy Institute. He is active in the National Research Council, serving as cochair of the Chemical Sciences Roundtable and as a member of the Chemical Engineering Peer Committee. He has also served on the Panel on Chemical Science and Technology, the Committee on the Review of Basic Energy Sciences Catalysis Program, and the Committee on Challenges for the Chemical Sciences in the 21st Century. He was elected to the National Academy of Engineering in 2006. He received a BS in chemical engineering from Washington University in St. Louis, Missouri, and an MS and a PhD in chemical engineering from Stanford University.

Y. Frank Cheng is Professor and Canada Research Chair in Pipeline Engineering in the Department of Mechanical and Manufacturing Engineering at the University of Calgary. His research has focused on pipeline corrosion, stress corrosion cracking, erosion–corrosion, coatings, metallurgical microelectrochemistry, and defect assessment. Before joining the faculty of the University of Calgary in 2005, he was a Natural Sciences and Engineering Research Council of Canada postdoctoral fellow at the Nova Research and Technology Center and a research scientist at the Center for Nuclear Energy Research at the University of New Brunswick. He is a member of the editorial board of *Corrosion Engineering, Science and Technology* and has published more than 120 articles in refereed journals on corrosion and pipeline engineering. He is the sole author of *Stress Corrosion Cracking of Pipelines*, published by Wiley. He is also Theme Editor of Pipeline Engineering for the *Encyclopedia of Life Support Systems* developed under the auspices of the United Nations Educational, Scientific, and Cultural Organization. He holds a BS in corrosion from Hunan University, an MS in materials engineering from the Institute of Metal Research from the Chinese Academy of Sciences, and a PhD in materials engineering from the University of Alberta.

James F. Dante is Manager of the Environmental Performance of Materials Section of the Southwest Research Institute. In this capacity, he supervises 15 staff engineers and technicians involved in basic and applied corrosion research for the energy industry and the U.S. Departments of Defense, Transportation, and Energy. Current programs include corrosion sensor research and implementation involving fluidized sensors, atmospheric corrosion sensors, and sensors for corrosion under insulation. His unit also conducts research on accelerated corrosion test methods and research to advance the mechanistic understanding of corrosion processes in various industries. Before joining Southwest Research Institute in 2009, he was Senior Research Scientist at Luna Innovations and leader of the University of Dayton Research Institute's group specializing in corrosion mechanisms, detection, and protection. He began his career as a materials research engineer at the National Institute of Standards and Technology. He holds a BA in physics from Johns Hopkins University and an MS in materials science and engineering from the University of Virginia.

H. Scott Fogler is Vennema Professor of Chemical Engineering and Arthur F. Thurnau Professor at the University of Michigan. He is internationally recognized for his research and teaching in chemical reaction engineering in petroleum engineering, including reaction in porous media, fused chemical relations, kinetics of wax deposition, gelation kinetics, asphaltene deposition kinetics, remediation colloidal phenomena, and catalyzed dissolution. The Chemical Manufacturers Association honored him with the National Catalyst Award in 1999. He has published more than 200 articles in peer-reviewed journals and books. He is author of *Elements of Chemical Reaction Engineering*, which is in its fourth edition and is estimated to be used by three-quarters of all chemical engineering programs in the United States. He has received numerous awards from the American Society for Engineering Education, including the Dow Outstanding Young Faculty Award in 1972, the Corcoran Award for Best Paper in Chemical Engineering Education in 1993, and the Lifetime Achievement Award from the Chemical Engineering Division in 2005. He earned a BS in chemical engineering from the University of Illinois and an MS and a PhD in chemical engineering from the University of Colorado.

O. B. Harris is President of O. B. Harris, LLC, an independent consultancy specializing in the regulation, engineering, and planning of petroleum liquids pipelines. From 1995 to 2009, he was Vice President of Longhorn Partners Pipeline, LP, which operates a 700-mile pipeline that carries gasoline and diesel fuel from Gulf Coast refineries to El Paso, Texas. In this position, he was responsible for engineering, design, construction, and operation of the system. From 1991 to 1995, he was President of ARCO Transportation Alaska, Inc., a company owning four pipeline systems, including the Alyeska Pipeline Service Company, which transports 25 percent of the crude oil from the North Slope of Alaska to the Port of Valdez. From 1977 to 1990, he held several supervisory and managerial positions at ARCO Pipeline Company, including District Manager for Houston and Midland, Texas; Manager of the Northern Area; and Manager of Products Business. At ARCO Transportation, he directed the efforts of a team of corrosion engineers advising Alyeska on making repairs to the Trans-Alaska Pipeline System. He is a past member of the Board of Directors of the Association of Oil Pipe Lines and the Pipeline and Hazardous Materials Safety Administration's Technical Hazardous Liquids Pipeline Safety Standards Committee. He holds a bachelor's degree in civil engineering from the University of Texas and an MBA from Texas Southern University.

Brenda J. Little is Senior Scientist for Marine Molecular Processes in the Naval Research Laboratory (NRL) at the Stennis Space Center. Earlier she was a Supervisory Research Chemist, Principal Investigator in the Biological and Chemical Oceanography Branch, Supervisory Oceanographer, and Head of the Biological and Chemical Oceanography Branch. During her 35-year career at NRL, she has made major contributions in identifying and understanding microbiologically influenced corrosion of marine materials, which has had a significant impact on a broad spectrum of Navy applications. Her research has been used to prevent and mitigate corrosion problems in seawater piping systems, fire protection systems, weapon cooling systems, helicopter interiors, and nuclear waste storage. She participated in a special U.S. Department of Transportation investigation of corrosion mechanisms in the Alaska North Slope pipeline. She is Assistant Editor of *Biofouling,* the *Journal of Bioadhesion,* and *Biofilm Research.* She coauthored (with J. S. Lee) *Microbiologically Influenced Corrosion* (John Wiley and Sons, 2007). She has published more than 80 journal articles, more than 100 papers in symposium proceedings, and more than 20 book chapters. Her publications have earned her numerous NRL publication awards. She is a Fellow of the National Association of Corrosion Engineers (NACE) and a recipient of the Navy Meritorious Civilian Service Award and Women in Science and Engineering Award for Scientific Achievement. She holds a BS in biochemistry from Baylor University and a PhD in chemistry from Tulane University.

Mohammad Modarres is Minta Martin Professor of Engineering and Professor of Nuclear and Reliability Engineering and Director of the Reliability Engineering Program at the University of Maryland, College Park. His research centers on probabilistic risk assessment; uncertainty analysis; and the physics of failure mechanisms of mechanical components, systems, and structures. He has served as a consultant to several governmental agencies, private organizations, and national laboratories in areas related to probabilistic risk assessment, especially applications to complex systems such as nuclear power plants and pipelines. He has authored more than 300 papers in archival journals and proceedings of conferences and three books in various areas of risk and reliability engineering. He is a member of several journal editorial boards, including the *Reliability Engineering and System Safety Journal*, *Journal of Risk and Reliability,* and *International Journal of Reliability and Safety*. He is Associate Editor of the *International Journal on Performability Engineering*. He holds a master's degree in mechanical engineering and a PhD in nuclear engineering, both from the Massachusetts Institute of Technology.

W. Kent Muhlbauer is Founder and President of WKM Consultancy, which provides consulting services on all aspects of pipeline design, operations, and maintenance with an emphasis on risk management. Clients include major U.S. and international pipeline operators, federal and state regulatory agencies, engineering companies, and insurance companies. Pipeline risk assessment techniques developed by WKM are in use by pipeline operating companies worldwide. Before forming WKM in 1995, he designed, constructed, and maintained pipeline systems for Dow Chemical's Pipeline Division. He held a variety of engineering and management positions starting in 1982, including operations engineer, technology center specialist, pipeline and salt dome storage quality manager, control center supervisor, and regional operations and maintenance manager. He is author of the *Pipeline Risk Management Manual* (Elsevier 1992, 1996, 2004) and author of numerous articles and papers on pipeline risk management. He is a frequent speaker and instructor at conferences, workshops, training sessions, and seminars on pipeline risk management and integrity preservation. He holds a BS in civil engineering from the University of Missouri.

Srdjan Nešić is Professor of Chemical Engineering and Director of the Institute for Corrosion and Multiphase Flow Technology at Ohio University. Before joining the faculty of Ohio University in 2002, he was a Senior Lecturer in the Mechanical Engineering Department of the University of Queensland, Brisbane, Australia; Principal Research Scientist at the Institute for Energy Technology, Kjeller, Norway; and Research Scientist at Vincha Institute for Nuclear

Sciences, Belgrade, Hungary. His expertise is in flow effects and erosion of pipelines, electrochemical corrosion, computational and experimental fluid dynamics, and multiphase flow. He has authored more than 50 peer-reviewed journal articles on these subjects and more than 100 conference papers. He is a Fellow of NACE and has chaired numerous NACE technical sessions and conferences on internal pipeline corrosion and erosion. He is a member of the editorial board of the *Corrosion Journal*. He holds bachelor's and master's degrees in mechanical engineering from the University of Belgrade and a PhD in chemical engineering from the University of Saskatchewan.

Joe H. Payer is Chief Scientist at the National Center for Education and Research on Corrosion and Materials Performance and Research Professor of Corrosion and Reliability Engineering at the University of Akron. In this position he directed the University Corrosion Collaboration for the U.S. Defense Department's Office of Corrosion Policy and Oversight. Before joining the University of Akron in 2009, he was Professor of Materials Science at Case Western Reserve University, where he directed the U.S. Department of Energy's multiuniversity Corrosion and Materials Performance Cooperative for improved performance assessment for long-term disposal of spent nuclear fuel. His expertise is in materials selection, failure analysis, corrosion control methods, monitoring systems, and degradation mechanisms. His research has focused on localized corrosion of highly corrosion-resistant materials, gas and oil pipeline integrity, the effects of manufacturing processes on the performance and reliability of materials in service, coatings and surface treatments, and hydrogen and materials interactions. He is a Fellow of the American Society for Metals International; a Fellow and Past President of NACE; and a recipient of the American Society for Testing and Materials Sam Tour Award for Distinguished Contributions to Research, Development, and Evaluation of Corrosion Testing Methods. He earned a BS and a PhD in metallurgical engineering from Ohio State University.

Richard A. Rabinow is President of the Rabinow Consortium, LLC, which provides economic and business consulting services to the pipeline industry. He retired from ExxonMobil after a 34-year career with the corporation. At the time of his retirement in 2002, he was President of ExxonMobil Pipeline Company (EMPCo), a position he had held at EMPCo and its predecessor, Exxon Pipeline Company, since 1996. Before that, he was Vice President and Lower 48 Manager of Exxon Pipeline Company. He began his career at the Exxon Company in 1968, where he held several engineering and supervisory positions in refineries. He rose to Executive Assistant to the President of Exxon Company, Baytown Refinery Manager, Manager of Corporate Affairs, Manager of the Environmental and Safety Department. He is a past Chairman of the Association of Oil Pipe Lines and the Owners Committee of the Trans-Alaska Pipeline System. He has served on the Transportation Research Board's Committee for Pipelines and Public Safety and the Committee on Alaska's Oil and Gas Pipeline Infrastructure. He received a BS in engineering mechanics from Lehigh University and MS degrees in mechanical engineering and management, both from the Massachusetts Institute of Technology.

George W. Tenley, Jr., retired in 2010 as President of the Pipeline Research Council International (PRCI). PRCI is the collaborative research and development program for the energy pipeline industry. He joined PRCI in 1999 after working as an independent consultant on pipeline integrity planning and as a strategic advisor on pipeline risk management for Battelle Memorial Institute. From 1989 to 1995, he was Associate Administrator for Pipeline Safety in the U.S. Department of Transportation. In this position, he was the senior federal official responsible for safety regulations governing the pipeline transportation of hazardous liquids and natural gases. From 1976 to 1989, he was a senior attorney and then Chief Counsel for the Research and Special Programs Administration. He began his career as an attorney for the Federal Aviation Administration and the Drug Enforcement Administration. He earned a BA in political science from the University of Maryland and a JD from the University of Maryland.