SCC
STRESS CORROSION CRACKING

National Energy Board
Office national de l'énergie

R E P O R T O F T H E I N Q U I R Y

Stress Corrosion Cracking on Canadian Oil and Gas Pipelines

DECEMBER 1996 MH-2-95

National Energy Board

Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines

MH-2-95

REPORT OF THE INQUIRY

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National Energy Board | Office national de l'énergie

November 22, 1996

Mr. R. Priddle
Chairman
National Energy Board

Dear Mr. Priddle:

We have completed the public inquiry into stress corrosion cracking on Canadian oil and gas pipelines in accordance with the Board's terms of reference of 6 September 1995.

We are now pleased to make our report to the Board pursuant to section 15 of the *National Energy Board Act*. In accordance with the terms of reference, this report is also being made available to the public.

We trust that the Board will find that we have fulfilled our mandate and we respectfully request that the Board accept the report and act on the recommendations contained in it.

Yours truly,

K.W. Vollman
Presiding Member

A. Côté-Verhaaf
Member

R. Illing
Member

Summary and Recommendations

Twenty-seven recommendations to promote public safety on Canada's buried oil and gas pipelines are presented in this report. They result from a series of findings of an extensive National Energy Board (Board) public inquiry into the problem of near-neutral pH stress corrosion cracking (SCC). The Inquiry was conducted by three members of the Board. This is our report.

Why this Inquiry?

The occurrence of SCC on Canadian pipelines is a serious matter. Concern about SCC on the TransCanada PipeLines Limited (TransCanada) system led to the Board conducting an earlier inquiry in 1993. From that Inquiry, the Board concluded that the SCC situation was being managed appropriately by the affected pipeline companies considering the extent of the problem as then seen.

However, there were two more major ruptures and fires on the TransCanada system in February and July 1995, the last one at a location where it was not believed that SCC could occur.

These two pipeline failures, together with further evidence of the more widespread nature of SCC and awareness that research was producing new insights into SCC, led the Board to initiate this Inquiry in August 1995.

The Inquiry has been far-reaching across Canadian pipelines and has extended to other countries to take advantage of experience and expertise there. This Inquiry is the first comprehensive one in the world on SCC and the results, as well as providing valuable scientific and technical data that relate to the Canadian situation, could be of interest and use outside Canada.

What is SCC?

Stress corrosion cracking on pipelines begins when small cracks develop on the outside surface of the buried pipeline. These cracks are initially not visible to the eye and are most commonly found in "colonies", with all of the cracks positioned in the same direction. Over a period of years, these individual cracks may lengthen and deepen and the cracks within a colony may join together to form longer cracks. Since SCC develops slowly, it can exist on pipelines for many years without causing problems. But if a crack becomes large enough, eventually the pipeline will fail and will either leak or rupture.

Industry's experience with SCC

Since 1977, SCC has caused 22 pipeline failures in Canada. These failures include 12 ruptures and 10 leaks on both natural gas and liquids pipeline systems. Most of the SCC-related failures occurred since 1985 on pipelines that were coated with polyethylene tape and installed between 1968 and 1973.

Our understanding of SCC

Although there is much research still to be done to fully understand SCC, the evidence indicates that SCC initiates as a result of the complex interaction of three conditions:

- a potent environment at the pipe surface,
- a susceptible pipe material, and
- a tensile stress.

All three conditions must be present for SCC to occur.

A number of soil and groundwater properties play a role in producing a potent environment at the pipe surface. In order for SCC to initiate, there must be a breakdown in the pipe coating and the cathodic protection.

Any commonly used pipeline steel was found to be susceptible to SCC. However, we found the Youngstown-manufactured pipe on a portion of the TransCanada system in southern Ontario to be particularly susceptible to SCC.

The operating pressure of the pipeline is normally the principal contributor to tensile stress. Field data and laboratory data indicate that stress has an effect on initiation and possibly on the growth rate of cracks. Fluctuations in stress levels and the rate of change of these stresses also play a role. However, we found that, in spite of considerable research, the available information on the contribution of stress to SCC is limited and sometimes conflicting.

In fact, research has not determined a threshold stress below which cracks will not initiate and grow to failure.

Finally, we believe that the three conditions necessary for "significant" SCC co-exist only on a small portion of the pipeline systems in Canada. For example, TransCanada has estimated that less than four percent of its system is susceptible to "significant" SCC.

Can the SCC problem be dealt with?

The short answer is yes.

It is important to define the problem as primarily existing on pipelines which were constructed in the 1960s and 1970s using polyethylene tape as a protective coating. This coating has tended to separate (disbond) from the pipeline and allow moisture to contact the pipeline. Because polyethylene tape is an insulator, it shields the pipe steel from cathodic protection current, even if it disbonds.

Knowing which pipelines are most susceptible to SCC makes attacking the problem, if not simple, at least definable. The problem is being systematically addressed on the most affected pipelines, and major programs to find and eliminate it are underway, but more remains to be done.

For newer pipelines, the use of different coatings (primarily fusion bonded epoxy) continues to demonstrate great effectiveness in preventing the initiation of SCC as long as both the pipe sections and the field welds connecting those sections employ similarly effective coatings.

The SCC problem can be expected to be significantly reduced and even eliminated as polyethylene tape-coated pipe is systematically investigated and SCC is found and removed. It will, though, take time and money.

What has been done?

This Inquiry has found that Canadian pipeline companies are taking SCC very seriously and are collaborating in research efforts and in the exchange of information on the management of the problem.

In total, the 13 members of the Canadian Energy Pipeline Association (CEPA) planned to spend $4.8 million on SCC research and over $30 million on pipeline maintenance related to SCC in 1996. TransCanada alone has spent $202 million on its SCC management program since 1985. These efforts have resulted in considerable progress in the search for the answers to SCC. Effective tools have been developed which, when used in a systematic manner, will reduce the possibility of a failure due to SCC.

Pipeline companies are making progress in checking their pipeline systems for SCC. However, given the extent of the pipeline network in Canada and the different rates at which individual companies are able to check their systems, we cannot say that all the SCC that exists on Canadian pipelines has been found.

What needs to be done?

We know that SCC remains a serious concern for the pipeline industry and for us as regulators. Since SCC is a time-dependent process, without proper attention, it will worsen and be the cause of more pipeline failures. We believe that a comprehensive approach to the SCC problem includes:

- implementation of an SCC management program by each pipeline company;
- changes to the design of pipelines;
- continued research;
- establishment of an SCC database;
- improved emergency response practices; and
- continued information sharing.

Appropriate operating pressures

In looking at the elements of an effective SCC management program, we also considered whether a reduction in operating pressure would be an effective way to deal with SCC on existing pipelines. As there is no clear evidence of a threshold level of pressure below which SCC will not initiate and grow, a pressure reduction will not prevent failures and will be very costly. We find that there are other measures which are more systematic, efficient and effective in mitigating SCC and thereby promoting public safety. Therefore, we believe that a general reduction in pressure would not be a logical or effective response to the SCC problem.

However, as decreasing the pressure in a pipeline means a larger defect will be required before failure, pressure reduction should be considered as a temporary measure for sections of a pipeline system where there is a threat of imminent failure. Reduced operating pressure can also be used effectively in combination with other mitigative measures, as part of an effective SCC management program.

SCC management program

The most effective method of addressing the issue of SCC would be through company-specific SCC management programs which require the systematic application to specific pipelines of the knowledge and best practices already developed across the industry.

The objective of the programs would be to identify areas where SCC may be found, to find it and then deal with it. Detection can be done through investigative excavations based on predictive models or by hydrostatic retesting. Emerging technology such as advanced in-line inspection tools will also assist in detecting SCC.

Design changes

When a reliable crack detection tool becomes available, it can be used to provide a company with more complete and accurate information on the condition of its pipeline. The ability of a pipeline to accommodate the passage of in-line inspection devices significantly facilitates the maintenance of the integrity of that pipeline, not only with respect to SCC, but with most integrity issues. We therefore recommend that new pipelines be designed to allow the passage of in-line inspection tools.

Effective protective coatings play a fundamental role in the prevention of SCC. Several pipeline coatings have demonstrated effective protection against SCC in the long-term. However, some newer coatings have not yet demonstrated their long-term performance. We therefore recommend that standard tests be developed and field and laboratory studies be done to verify whether these coatings will continue to perform over the life of the pipeline.

Research

It is essential to continue research into SCC. Many of the basic questions on initiation and growth of SCC have not yet been answered. As well, there is a need to continue to develop effective mitigative measures to deal with SCC. Most notably, the refinement of SCC in-line inspection tools would significantly improve the industry's ability to detect and manage SCC.

A database on SCC

We are of the view that the careful collection and analysis of field experience is very important in understanding SCC. An industry-wide database on SCC is essential, primarily because it will help to identify those combinations of environmental and operating conditions that most influence the initiation and growth of SCC.

Emergency response practices

We believe that people living and working near pipelines should have a better understanding of what to do in the event of a pipeline failure. Clearly, the primary responsibility for communication on pipeline safety rests with the pipeline companies that operate the systems. In consultations with communities, NEB representatives heard residents and first responder organizations express a need for more and better information about emergency procedures and – particularly for first responders – for training. In addition, they heard suggestions for changes to the NEB's own field practices.

Information sharing

We discovered that, although the Inquiry did not set out to serve as a forum for information-sharing, participants had the opportunity to learn about the work others were doing. It is important that this information-sharing process continues.

Recommendations

While the scope of the Inquiry is necessarily limited to those facilities which the National Energy Board regulates, much relevant information was provided by non-jurisdictional companies, (mainly) via CEPA, some of whose members are subject to provincial jurisdiction. We have taken careful account of this information and have displayed elements of it in our report, particularly in tabular form. We feel that this has enabled us to report comprehensively on the SCC problem as a Canada-wide phenomenon and has of course contributed valuably to the development of our recommendations which, however, relate solely to those companies which are subject to the Board's jurisdiction.

As a result of having considered all of the information presented to us over the course of the Inquiry, we recommend the following:

SCC management program

While a number of SCC management programs (for example, TransCanada's) are well underway, we **recommend**:

- that the Board require each pipeline company to develop and implement an SCC management program by 30 June 1997 *(Recommendation 6-1, p. 112);*
- that the Board require SCC management programs to identify the accountability for the implementation of the program *(Recommendation 6-2, p. 112);*
- that the Board require SCC management programs to provide for the review of the company's entire system and for regular updating *(Recommendation 6-3, p. 112);*
- that the Board require SCC management programs to consider the consequences and the probabilities of a failure when establishing priorities for investigative, mitigative and preventive activities *(Recommendation 6-4, p. 112);*
- that the Board require that SCC management programs contain three principal components:

a) determination of pipeline susceptibility to SCC and active monitoring of pipelines believed to be susceptible to SCC;

b) required mitigation, if "significant" SCC is found, and clear identification of the criteria a company must consider in deciding among mitigative options; and

c) recording and sharing of information on susceptible pipelines *(Recommendation 6-5, p. 112)*;

- that the Board require companies to report immediately to the Board any finding of "significant" SCC and any immediate mitigative actions taken and to develop and submit a plan detailing the specific mitigative measures to be implemented and a schedule of implementation *(Recommendation 6-6, p. 112);*
- that, as part of its ongoing monitoring activities, the Board audit the documentation of SCC management programs *(Recommendation 6-7, p. 113);*
- that the Board request that CEPA continue

development of its Recommended Practices Manual and file it with the Board by 31 March 1997 *(Recommendation 6-8, p. 113);*

- that the Board request that CEPA develop procedures for the detection and mitigation of circumferential SCC and include them in future versions of the Recommended Practices Manual *(Recommendation 6-9, p. 113);*
- that, if there is reason to believe that sections of a pipeline may be susceptible to SCC, the Board require the pipeline company to develop a predictive model to identify and prioritize sites for an investigative excavation program *(Recommendation 4-2, p. 64);*
- that the Board request that CEPA develop sampling criteria for verifying the accuracy of predictive models *(Recommendation 4-3, p. 65);*
- that the Board require that, where a hydrostatic retest program forms part of an SCC management program, it be properly designed for the particular pipeline under consideration. The design should take into account factors such as the material and geometric properties of the pipe, the operating history of the pipeline, its future operating conditions, and field and laboratory data on crack sizes and crack growth. Where reliable data are not available, conservative assumptions should be made *(Recommendation 4-6, p. 88)*;
- that the Board request that the CSA Technical Committee on Oil and Gas Industry Pipeline Systems:

a) incorporate, in the next edition of CSA Z662 Oil and Gas Pipeline Systems standard, requirements for hydrostatic retesting as an option for maintaining pipeline integrity; and

b) amend the current pressure testing requirements of the standard in light of the findings from the recent studies on hydrostatic testing *(Recommendation 4-7, p. 88)*;

- that the Board request that CEPA:

a) continue the development and verification of models that predict the hazards and consequences associated with pipeline failures for different service fluids; and

b) develop criteria for determining safe distances from the effects of pipeline failures *(Recommendation 4-8, p. 92)*;

- that the Board require that pressure reduction be included as part of all SCC management programs and considered for use:

a) in combination with investigative excavations and other mitigative measures such as hydrostatic retesting and in-line inspection; and

b) as a temporary measure where there is a threat of imminent failure, in which case it should be maintained until the integrity of the pipeline is re-established *(Recommendation 4-5, p. 80)*; and

- that the Board require pipeline companies to examine ERW pipe manufactured by Youngstown Sheet and Tube located in SCC susceptible soils for evidence of SCC *(Recommendation 3-1, p. 54).*

Design changes

We **recommend**:

- that the Board require that new large diameter transmission pipelines be designed and constructed to accommodate the passage of in-line inspection tools *(Recommendation 4-4, p. 76);* and
- that the Board request that the CSA Technical Committee on Oil and Gas Industry Pipeline Systems, the pipeline industry and coating manufacturers coordinate efforts to:

a) develop standard tests, where none currently exist, that determine whether a coating will meet the performance criteria set out in the CSA Z662-94 standard over the anticipated service life of a pipeline;

b) incorporate those tests in the appropriate CSA standards; and

c) conduct objective studies based on those tests to demonstrate the long-term performance of the different types of coatings currently available for pipelines *(Recommendation 4-1, p. 60).*

Research

We **recommend**:

- that the Board request that CEPA continue its SCC research program and expand the program to include SCC experts from other industries and a wider range of disciplines *(Recommendation 6-13, p. 119);*
- that the Board request an annual status report from CEPA on SCC research activities highlighting

accomplishments for the year and plans for future research, indicating priorities, time lines and funding levels. *(Recommendation 6-14, p. 119);* and

- that the Board request that CEPA provide, by 30 June 1997, an analysis of the extent to which the areas of incomplete research identified in this report are addressed in the current SCC research program and the merits and implications of expanding this program to cover these areas *(Recommendation 3-2, p. 54)*.

SCC database

We **recommend**:

- that the Board request that CEPA continue to develop and maintain a database on SCC that is compatible with other international initiatives and that CEPA encourage the participation of non-member pipeline companies *(Recommendation 6-10, p. 114)*;
- that the Board require pipeline companies to provide SCC-related data to the CEPA SCC database as they acquire it *(Recommendation 6-11, p. 115);* and
- that the Board request that CEPA provide the results of the first data trend analyses to the Board as proposed including any additional trends analyses requested by the Board. As well, we recommend that other interested parties (for example, researchers and the public) be given the opportunity to identify the particular trends analyses that they require *(Recommendation 6-12, p. 115).*

Emergency response practices

We **recommend**:

- that, as part of its ongoing monitoring activities, the Board review companies' emergency response practices to ensure that adequate training is provided to first responder organizations and that appropriate information is provided to the communities on the proper procedures to follow in the event of pipeline emergencies *(Recommendation 5-1, p. 99);* and
- that the Board expand the scope of its accident investigation program to include community relations and emergency response related issues *(Recommendation 5-2, p. 100).*

Information sharing

We **recommend**:

- that the Board request that CEPA and other industry organizations create opportunities, through conferences and workshops, for the continued sharing of information among industry, researchers, regulatory agencies and the public about SCC field experience and research developments *(Recommendation 6-15, p. 120).*

Abbreviations

Act	National Energy Board Act
AB	Alberta
AEC	Alberta Energy Company Ltd.
AEUB	Alberta Energy and Utilities Board
AGA	American Gas Association
ANG	Alberta Natural Gas Company Ltd
a_o	critical crack size at maximum operating pressure
AS	Australian Standard
ASME	American Society of Mechanical Engineers
a_T	critical crack size at test pressure
Board	National Energy Board
BC	British Columbia
°C	degree Celsius
CANMET	Canadian Centre for Mineral and Energy Technology
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Energy Pipeline Association
CGA	Canadian Gas Association
CGHAZ	coarse-grained heat-affected zone
CO_2	carbon dioxide
Cochin	Cochin Pipe Lines Ltd.
CP	cathodic protection
CSA	Canadian Standards Association
CSA Z662	CSA standard Z662-94, Oil and Gas Pipeline Systems
D	diameter
DSAW	double submerged arc weld
EAC	environmentally assisted cracking
ERW	electric resistance weld
EWIV	Elastic Wave Inspection Vehicle
FBE	fusion bonded epoxy
FPL	Foothills Pipe Lines Ltd.
GRI	Gas Research Institute
HAZ	heat affected zone

HIC	hydrogen induced cracking
HVP	high vapour pressure
INGAA	Interstate Natural Gas Association of America
ILI	in-line inspection
IPL	Interprovincial Pipe Line Inc.
km	kilometre
kPa	kilopascal
ksi	thousand pounds per square inch
kW/m^2	kilowatt per square metre
LVP	low vapour pressure
m	metre
MB	Manitoba
MFL	magnetic flux leakage
MIACC	Major Industrial Accidents Council of Canada
mm	millimetre
mm/s	millimetres per second
mm/yr	millimetres per year
MMcfd	million cubic feet per day
MOP	maximum operating pressure
MPa	megapascal
$MPa\sqrt{m}$	megapascal square root metre
MPI	magnetic particle inspection
mV Cu/CuSO4	millivolts potential to reference copper/copper sulfate half cell
NDE	nondestructive examination
NDT	nondestructive testing
NEB	National Energy Board
NOVA	NOVA Gas Transmission Ltd.
NPS	nominal pipe size (in inches)
NRTC	Novacor Research & Technology Corp.
NUL	Northwestern Utilities Limited
O & M	operation and maintenance
ON	Ontario
OPLA	Ontario Pipeline Landowners Association
P	pressure
PAFFC	Pipe Axial Flaw Failure Criterion
PE	polyethylene
pH	measure of the acidity or alkalinity of a substance

PRASC	Pipeline Risk Assessment Steering Committee
PRC*I*	Pipeline Research Council *I*nternational (previously PRC)
psi	pounds per square inch
PTC	Petroleum Transmission Company
P_T	test pressure
SCC	stress corrosion cracking
SK	Saskatchewan
SMYS	specified minimum yield strength
SRB	sulfate reducing bacteria
t	wall thickness or time
TCPL or TransCanada	TransCanada PipeLines Limited
TGL	TransGas Limited
TMPL or Trans Mountain	Trans Mountain Pipe Line Company Ltd.
TNPI	Trans-Northern Pipeline Inc.
TSB	Transportation Safety Board of Canada
TQM	Trans Québec and Maritimes Pipeline
TÜV	TÜV Rheinland
U.K.	United Kingdom
U.S. or United States	United States of America
WEI or Westcoast	Westcoast Energy Inc.
Youngstown	Youngstown Sheet and Tube
Δ	delta (change in value)
µm	micrometre (1 million µm = 1 metre)
s	hoop stress

Chapter One

Pipelines in Canada

1.0 Introduction

The purpose of this Chapter is to provide general background information on oil and gas pipelines in Canada and to describe those national organizations which have a role in promoting pipeline safety. In subsequent chapters, we describe the considerations which led to this Inquiry, what we learned about stress corrosion cracking (SCC) and our conclusions about what needs to be done to address the SCC problem.

There are more than 540 000 kilometres (340,000 miles) of buried oil and gas pipelines throughout the country. They vary in size from 25 mm (1 inch) diameter plastic gas distribution lines to 1 219 mm (48 inch) diameter oil and gas transmission pipelines. These pipelines carry hydrocarbons in either gas or liquid form including natural gas, crude oil, high vapour pressure products such as propane and refined products such as gasoline or jet fuel.

Figure 1.1
Major natural gas pipelines in Canada

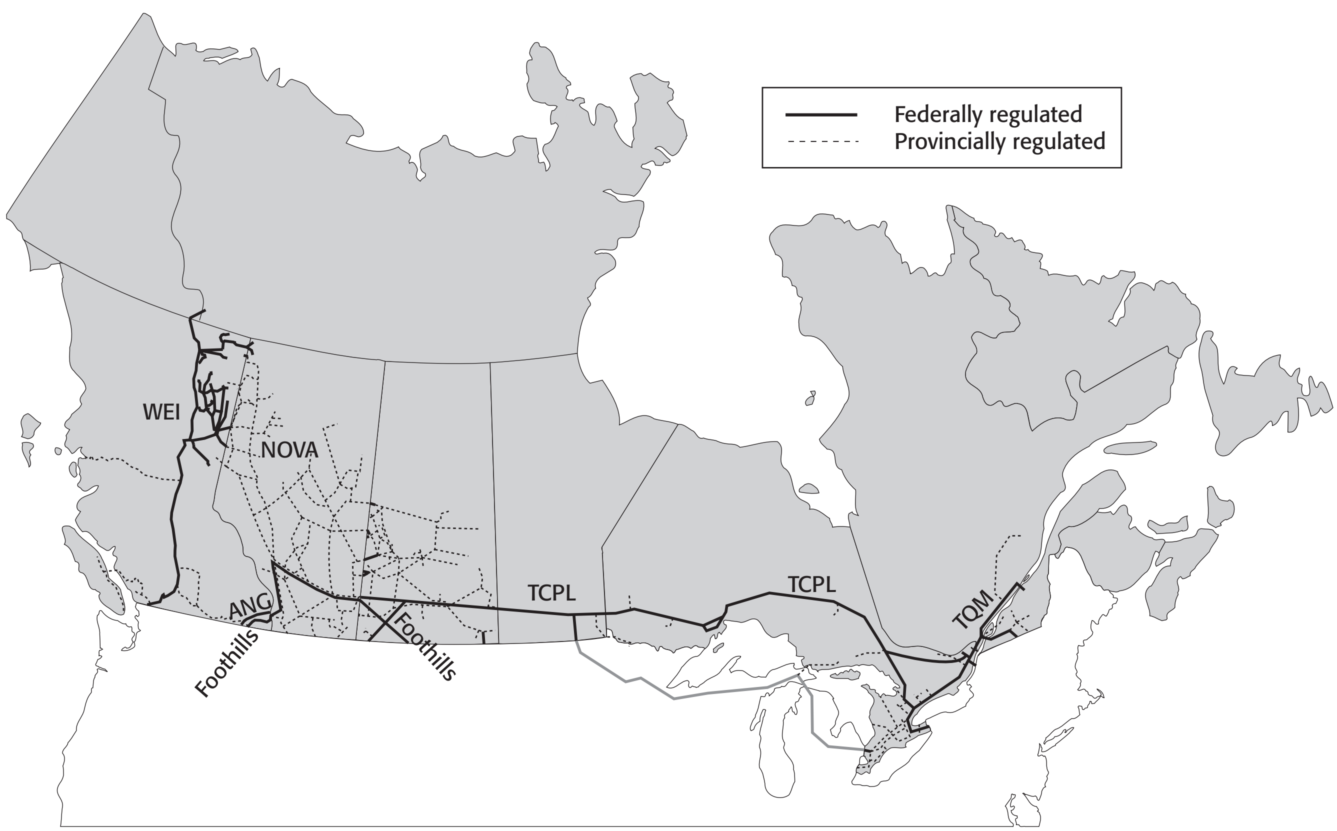


Figure 1.2
Major oil and products pipelines in Canada

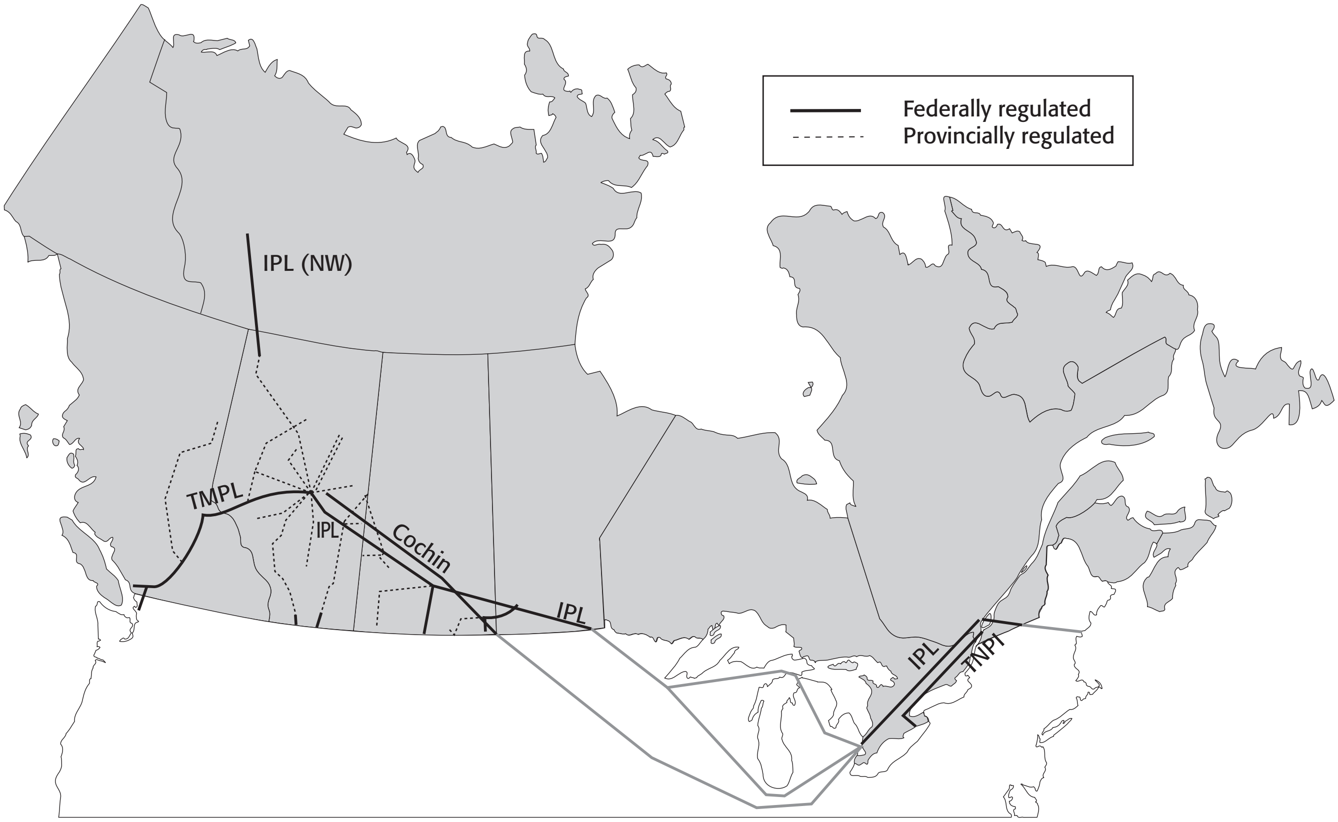
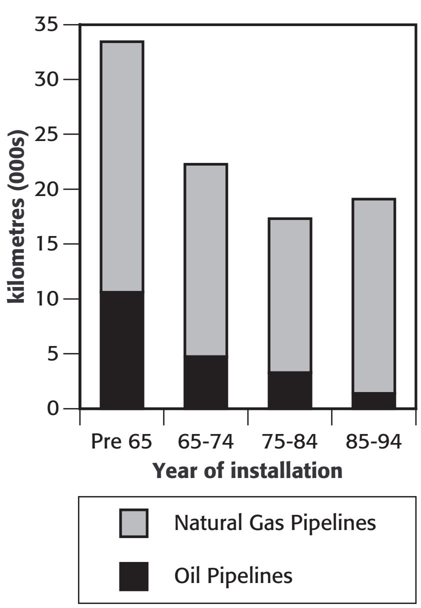


Figure 1.3
Age of transmission pipelines in Canada



Source: Endnote [1]

Pipelines are an efficient way to transport these products. Natural gas is moved through a continuous network of connected pipelines from gas fields located mainly in Western Canada to markets throughout Canada and the U.S. In its journey across the country, natural gas is compressed to as high as 8 700 kPa (1,260 psi) and moved in high-pressure steel transmission pipelines. When the gas reaches the community where it is to be used, it is distributed directly to customers through low-pressure pipelines. Crude oil is also produced mainly in Western Canada and shipped by pipeline to refineries across the continent (Figure 1.4).

Energy production and transportation are very important to the Canadian economy. Nearly two-thirds of Canada's energy supply moves through pipelines and virtually all oil and gas exports – worth $15 billion in 1995 – are carried by pipeline.

The routes for most of Canada's high-pressure pipelines were determined in the 1950s when the major pipeline systems were established. Most of this original pipe remains in service today. However, the pipeline companies have steadily increased the capacity of their systems by adding compressor stations, pumping stations and newer lines, many of which run parallel to the original pipelines.

1.1 Pipeline safety in Canada

Pipeline safety is an important issue because the products transported through pipelines are hazardous substances. There is always the chance that a pipeline could leak or rupture and a pipeline failure can have serious consequences for people living or working close by and for the environment. When a high-pressure natural gas pipeline breaks, an enormous amount of energy is released as the compressed gas expands. The escaping gas can ignite and cause extensive damage. When a pipeline carrying liquid hydrocarbons fails, the leaking contents can cause extensive environmental damage. Some of these liquids, like gasoline or jet fuel, can ignite and burn. The failure of a pipeline carrying propane or other high vapour pressure (HVP) products can produce a vapour cloud that can explode.

Despite the potential for serious accidents, the safety record of Canada's high-pressure pipelines has been good over their 40-year plus history. There are typically 30 to 40 failures each year on pipelines regulated by the NEB, most of them leaks, rather than ruptures. Since 1959, when the NEB was established, there has been only one death to a member of the general public resulting from the failure of a pipeline under NEB jurisdiction. That death occurred in 1985 when a drainage tile plow ruptured a gas pipeline.

A number of safety issues arise from pipeline construction and operation. These include everything from how pipelines are installed and operated, to the safety practices of people who work around pipelines, to issues like the one that concerns us here: stress corrosion cracking. The safety of pipelines is the result of continuous attention paid to these issues by several organizations. The pipeline industry has primary responsibility for pipeline safety and has in many ways taken

Figure 1.4
Edmonton tank farm

Edmonton is the commencement of two of Canada's major oil pipelines: IPL going east and TMPL going west.

THE NEB'S SAFETY ROLE...

Section 48 of the NEB Act states, in part:

48(1) To promote safety of operation of a pipeline, the Board may order the company to repair, reconstruct or alter part of the pipeline and may direct that, until the work is done, that part of the pipeline not be used or be used in accordance with such terms and conditions as the Board may specify.

(2) The Board may, with the approval of the Governor in Council, make regulations governing the design, construction, operation and abandonment of a pipeline and providing for the protection of property and the environment and the safety of the public and of the company's employees in the construction, operation and abandonment of a pipeline.

the lead in dealing with safety issues. In addition, three national organizations play different but complementary roles in pipeline safety.

1.2 The safety role of the National Energy Board

The NEB regulates any pipeline in Canada that crosses either provincial or international borders. The Board regulates about 40 000 kilometres (25,000 miles) of pipelines. The remaining pipelines are regulated by the province or territory within which the pipeline operates.

Generally, the pipelines regulated by the NEB are the large-diameter high-pressure transmission pipelines. For example, the NEB regulates two of the country's largest natural gas transmission pipeline systems: TransCanada PipeLines Limited (TransCanada) and Westcoast Energy Inc. (Westcoast). It also regulates the two largest liquids pipeline systems: Interprovincial Pipe Line Inc. (IPL) and Trans Mountain Pipe Line Company Ltd. (TMPL). In addition, it regulates over 60 smaller pipeline systems.

The NEB regulates many aspects of pipelines. It approves new pipeline construction, approves tolls paid to transport the oil or natural gas through the pipeline, ensures that all shippers have fair access and establishes the rules or regulations for the design, construction, operation and abandonment of pipelines.

The Board has set minimum technical requirements through the Onshore Pipeline Regulations. Occasionally, the NEB has used its authority to order pipeline companies to temporarily reduce operating pressure or to take other steps to ensure safe operation.

The NEB also has the authority to investigate or inquire into any accident involving a pipeline that it regulates. If, as a result of an investigation, the Board determines that there are safety concerns, it may order pipeline companies to take remedial action or it may make recommendations about how similar accidents might be prevented in the future. In some cases, the NEB may also make findings as to the cause of the accident and the factors that may have contributed to it.

1.3 The investigative role of the Transportation Safety Board of Canada

The Transportation Safety Board of Canada (TSB) has a mandate to advance safety for transportation modes under federal jurisdiction, including pipelines. It does this by, among other things, conducting independent investigations and, if necessary, public inquiries into transportation accidents in order to make findings as to their cause and contributing factors. When the TSB investigates a pipeline accident, the NEB is not permitted to investigate any matter related to the accident that is being investigated by the TSB.

1.4 The role of the Canadian Standards Association

The Canadian Standards Association (CSA) is a non-profit, independent, private-sector organization. It serves the public, governments and business as a forum for national consensus in the development of standards for many activities and products. Many CSA standards have been incorporated into provincial and federal laws. For example, the NEB's Onshore Pipeline Regulations require pipeline companies to comply with CSA standard Z662-94 Oil and Gas Pipeline Systems (CSA Z662). This standard was developed by committees representing the pipeline industry, product manufacturers and regulatory authorities, including the NEB and provincial regulators.

CSA Z662 describes in detail the technical requirements for pipeline systems, including how they must be designed, what materials may be used, how they may be installed and joined, how pressure tests are to be done, what methods are acceptable to control corrosion, and how the pipeline system is to be operated and maintained.

Many companies treat the CSA standards as minimum requirements and develop their own corporate standards that go beyond these requirements.

Chapter Two

An Inquiry into Stress Corrosion Cracking

2.0 Introduction

The previous chapter described the basic structure of the pipeline industry and the roles of the different organizations involved in pipeline safety. This chapter describes how stress corrosion cracking became an issue for the Board and a subject for an inquiry.

Stress corrosion cracking on pipelines begins when small cracks develop on the outside surface of the buried pipe. These cracks are initially not visible to the eye and are most commonly found in "colonies", with all of the cracks positioned in the same direction. Over a period of years, these individual cracks may lengthen and deepen and the cracks within a colony may join together to form longer cracks. Since SCC develops slowly, it can exist on pipelines for many years without causing problems. If a crack becomes large enough, the pipeline will eventually fail and either leak or rupture.

Stress corrosion cracking is not a problem unique to Canadian pipelines. SCC has been recognized as a cause of pipeline failures in countries around the world. Pipelines in Australia, Iran, Iraq, Italy, Pakistan, Saudi Arabia, the former Soviet Union and the United States have also been affected by SCC.

SCC is not the only problem that causes pipeline failures and threatens public safety. Pipelines have suffered the effects of general corrosion and have been damaged or ruptured when people have hit them accidentally while digging. Earth movements such as slides have also damaged buried pipelines. However, the pipeline industry has been dealing with these causes for a long time and has a good understanding of how to manage them. By contrast, the industry and the research community are still learning about SCC, particularly about the type of SCC which occurs on Canadian pipelines.

Our awareness of SCC on the Canadian pipelines we regulate began in 1985. TransCanada had three failures on the Northern Ontario portion of its pipeline between March 1985 and March 1986 (e.g., Figure 2.1). These failures were attributed to stress corrosion cracking and were considered at the time to be the first evidence of SCC in Canada although subsequently it was determined that SCC had been detected on other pipelines in the 1970s. The type of SCC which caused these failures was different from the "high pH" SCC that had been found on other pipelines in the world. At the time, this new form was called "low pH" SCC. More recently, and more correctly, this form of SCC has

Figure 2.1
SCC pipeline failure site: Lowther, Ontario, August 1985

been referred to as "near-neutral pH" SCC. (The differences between high pH and near-neutral pH SCC are explained in Chapter 3.)

In response to these early failures, TransCanada initiated a program in 1985 entitled the "Pipeline Maintenance Program". The purpose of the program was to investigate the SCC problem on the TransCanada system and find a solution to it. The program included several detection methods which are now used by several companies and which are discussed in Chapter 4. The TransCanada program also focused considerable research efforts on near-neutral pH SCC initiation and growth.

TSB 1992 RECOMMENDATIONS:

The National Energy Board ensure that the internal pressure in all federally regulated natural gas pipelines, where stress corrosion cracks have been found or are likely to exist, is below the threshold level for the origin or propagation of stress corrosion cracking; (P92-01)

The National Energy Board, in collaboration with industry, develop improved methods for detecting and specific directions for repairing stress corrosion cracks; and (P92-02)

The National Energy Board, in collaboration with provincial authorities and in consultation with industry, develop a set of operating restrictions to be applied industry-wide where stress corrosion cracking is suspected to exist in natural gas pipelines. (P92-03)

Source: Endnote [1]

2.1 The NEB's 1993 Inquiry

TransCanada experienced its fourth and fifth SCC-related pipeline ruptures in December 1991 near Cardinal, Ontario, and in July 1992 near Tunis, Ontario. Following its investigation of these failures, the TSB issued three interim recommendations in November 1992 to the NEB through the Minister of Energy, Mines and Resources [1].

In response to these recommendations, the NEB decided in December 1992 that holding an inquiry would be the best way to develop a response to the TSB as well as examining TransCanada's Pipeline Maintenance Program. The Inquiry was initiated under Board Order MHW-1-92 [2] and took place in early 1993, through a written process. A total of 47 parties participated in the Inquiry, commenting on the TSB recommendations and responding to a list of questions about SCC. As well, the NEB asked all pipeline companies that it regulated to report any SCC found on their systems.

In August 1993, the NEB issued its report on the MHW-1-92 Inquiry. In the report, the NEB responded to the TSB recommendations. The NEB concluded that [3]:

> *...restrictions on operating conditions are not a practical solution to problems caused by the* [near-neutral pH] *form of SCC found to date in Canadian pipelines. The evidence confirms that it is not currently possible to determine the threshold level for either initiation or propagation of* [near-neutral pH] *SCC. Imposition of arbitrary operating restrictions would not result in any quantifiable improvement in safety and would have substantial negative effects on producers and consumers of natural gas.*

The NEB concluded that *"...SCC is not a widespread problem in Canada, and that where SCC exists on federally-regulated pipelines, the problem is being managed in a responsible fashion."* [4] The NEB went on to say, however, that *"...due to the site-specific nature of the problem and the difficulties in detecting the many small cracks typical of SCC, it is possible that SCC exists and remains undetected on some of these pipeline systems."* [5] Consequently, the NEB encouraged all companies under its jurisdiction *"...to carefully review the TransCanada experience with respect to SCC, and to examine their own systems for SCC when opportunities occur while carrying out other inspection, repair or maintenance activities."* [6]

The Board also found that TransCanada had expended *"...an appropriate level of effort and resources in the continuing development and implementation of its Pipeline Maintenance Program to address the safety risk posed by SCC."* [7] The NEB supported TransCanada's proposal to perform hydrostatic retests more frequently and to replace any pipeline sections which were susceptible to SCC and which were near homes and populated areas. The Board also said it would *"...continue to follow future developments with respect to SCC research and detection and repair techniques and will be prepared to institute such measures as necessary to ensure public safety."* [8]

2.2 Events following 1993 Inquiry

Following the MHW-1-92 Inquiry, the NEB asked all pipeline companies it regulated to report on whether they had found any SCC in the investigations they had since carried out. Several companies said they had examined portions of their systems using techniques similar to those used by TransCanada. They reported that they found some SCC but that it was not severe.

Meanwhile, research into SCC was progressing. More was being learned about near-neutral pH SCC than had been known at the time of the MHW-1-92 Inquiry and more was being learned from the field, where stress corrosion cracking was being detected on a growing number of pipelines.

Then, TransCanada experienced its sixth and seventh ruptures due to SCC within six months of each other. In February 1995, not far from Vermilion Bay in Northern Ontario, SCC caused a pipeline failure and the escaping gas ignited. This section of pipe had been identified as being susceptible to SCC and had been hydrostatically retested as part of the company's ongoing Pipeline Maintenance Program several years earlier. In fact, the pipeline was scheduled for a retest when it failed. Following the failure, TransCanada tested other similar sections which had not been recently retested.

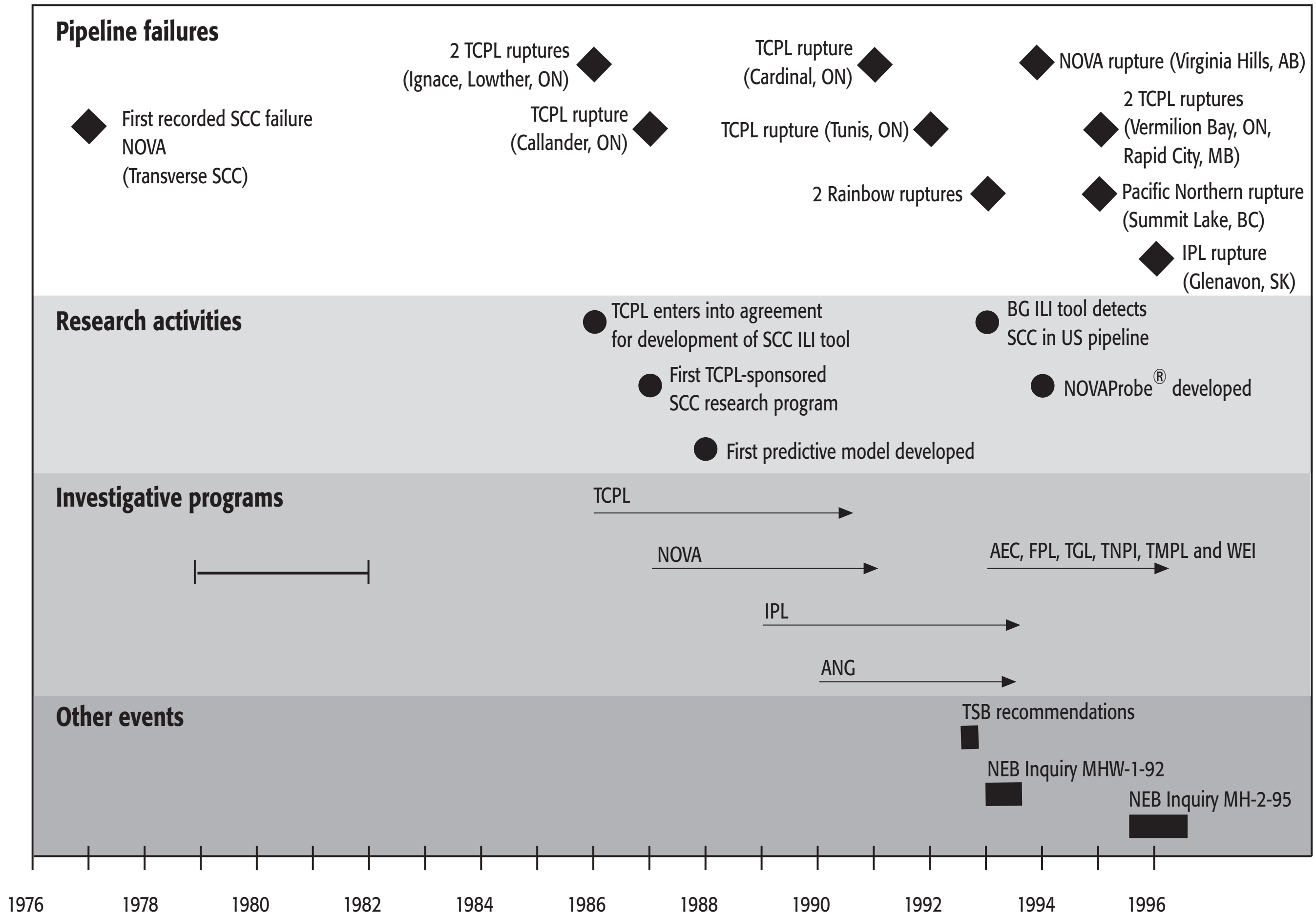
In July 1995, SCC caused a rupture on TransCanada's pipeline near Rapid City, Manitoba, resulting in a major explosion (Figure 2.2). Until that time, TransCanada had conducted a number of investigative digs in Western Canada and had not found any evidence of significant SCC on its system west of Winnipeg. As a result, TransCanada had focused its Pipeline Maintenance Program on its system east of Winnipeg. The Rapid City failure occurred downstream from a compressor station on a short section of pipe that was hand-wrapped with protective tape. (The remainder of the section was protected with a different type of coating considered effective against SCC.) However, in light of the amount of information that had been accumulating about SCC since the previous Inquiry, the Rapid City incident served to heighten concerns about what now seemed to be a widespread presence of SCC.

2.3 The NEB's 1995 Inquiry

In August 1995, the Board responded to these heightened concerns by initiating a wide-ranging public inquiry into SCC. (The Terms of Reference of the Inquiry can be found in Appendix I.)

Figure 2.2
SCC pipeline failure site: Rapid City, Manitoba, July 1995

Figure 2.3
Chronology of SCC events in Canada



Three Board members, Kenneth W. Vollman, Anita Côté-Verhaaf and Roy Illing, were authorized to form a panel, carry out the Inquiry and report their findings to the Board.

On September 20, 1995, the Inquiry Panel invited public participation in the Inquiry and issued "Directions on Procedure" and a preliminary list of issues to be addressed by the Inquiry.

One of the first tasks was to seek as much information about SCC as was available in order to gain a full understanding of the complexities of SCC. We wanted to use this Inquiry to create as complete a record as we could: one that would be balanced and that would include a broad range of experiences, research and views. We wanted to hear from people living near pipelines, research scientists and other experts, pipeline companies, industry associations and other regulatory agencies. The Preliminary List of Issues was used to guide discussions with these groups in a series of consultations and technical information meetings held between September 1995 and February 1996.

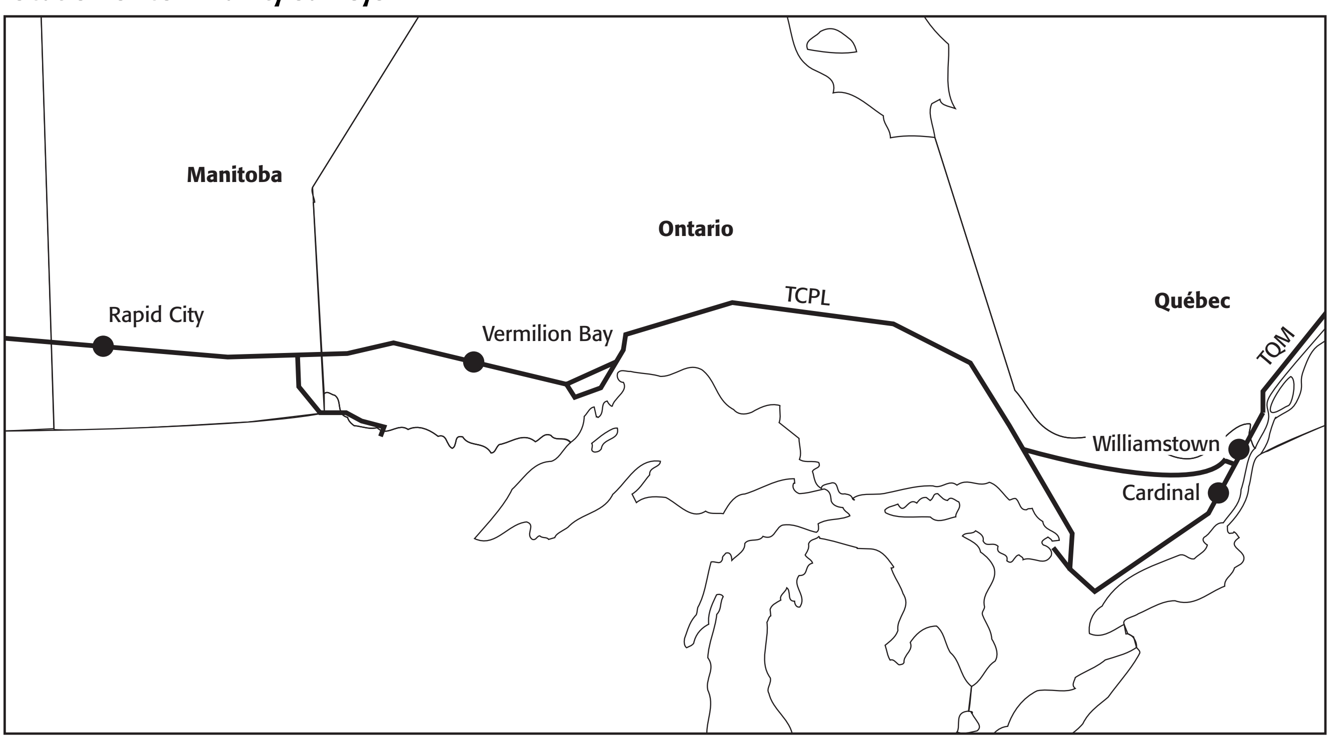
2.3.1 Consultations with the public

Clearly those people who live closest to pipelines face the most immediate effects of a pipeline failure. We were very sensitive to the effects of SCC failures on those people and specifically sought to obtain their views. As one of the first steps, NEB representatives and consultants met with residents and municipal officials in Rapid City, Manitoba, and Vermilion Bay, Williamstown and Cardinal, Ontario (Figure 2.4). These were locations where pipeline failures had occurred. NEB staff also met with representatives of the Ontario Pipeline Landowners Association (OPLA), a group of landowners based in southern Ontario, which had expressed an interest in the Inquiry. These meetings were recorded and summarized in reports. The concerns of landowners, nearby residents, local emergency response officials and local public officials were incorporated into the revised List of Issues, where our mandate permitted. We also committed to provide feedback to these communities following the Inquiry, as the communities had requested.

2.3.2 Technical information meetings

In late 1995 and early 1996, we held technical meetings to gather firsthand information about SCC and the issues surrounding it. We met with the following:

Figure 2.4
Location of community surveys



Pipeline operators and industry associations:

- TransCanada, NOVA Gas Transmission Ltd. (NGTL) and Mobil Oil Canada Ltd., the operator of Rainbow Pipe Lines Co. Ltd. (Rainbow), discussed their SCC experiences.
- The Canadian Energy Pipeline Association (CEPA) provided information on the experience of their member companies.
- The Interstate Natural Gas Association of America (INGAA) discussed the experience of their member pipeline companies.

Consulting and manufacturing firms:

- Camrose Pipe Company, a pipe manufacturer and Shaw Pipe Protection, a division of Shaw Industries Ltd., a pipeline coating manufacturer.
- British Gas plc (British Gas) and Pipetronix Ltd. (Pipetronix), leading developers of internal inspection tools for detecting cracks on pipelines.
- J.E. Marr Associates (Canada) Ltd., a company specializing in developing models to predict where SCC might occur and in carrying out field investigations for SCC.

Government agencies:

- The TSB and the Alberta Energy and Utilities Board (AEUB), the latter being responsible for regulating oil and gas pipelines under the jurisdiction of the province of Alberta.

Researchers:

- Battelle Memorial Institute (Battelle), Cortest Columbus Technologies, Inc. (Cortest), The Canadian Centre for Mineral and Energy Technology (CANMET) and Novacor Research Technology Corporation (NRTC).
- Pre-eminent SCC expert Dr. R.N. Parkins (Parkins), University of Newcastle-Upon-Tyne, England.

2.3.3 Public hearing

The next phase of the Inquiry was the public hearing. On December 6, 1995, we issued "Supplementary Directions on Procedure" and a revised List of Issues for the public hearing.

This revised List of Issues comprised six general topics:

- the extent and severity of SCC on oil and gas pipelines in Canada;
- the status of research into SCC on buried pipelines;

- the detection of SCC on buried pipelines;
- the mitigative measures for SCC on buried pipelines;
- prevention of initiation of SCC on buried pipelines; and
- the safety of the public and of company employees and the protection of the environment and property.

The complete List of Issues is included in Appendix II.

The public hearing portion of the Inquiry was held from April 15th to 23rd, 1996 in Calgary, Alberta, to examine witnesses and hear evidence of parties. All participants were invited to prepare written submissions based on the List of Issues. Parties submitted final argument in writing.

The following groups were active in the public hearing: British Gas, the Canadian Association of Petroleum Producers (CAPP), the Canadian Gas Association (CGA), CEPA, TransCanada and OPLA. A number of individual pipeline companies participated through the industry associations. As well, other participants including landowners, various individuals and organizations submitted letters of comment.

CEPA, which is made up of thirteen of the larger pipeline operators in Canada, played a major role in the Inquiry on behalf of its members. CEPA presented a large amount of technical data and called upon key witnesses, some from outside Canada, to respond to questions in the Inquiry. CEPA indicated its intention to play a key role in the follow-up to the Inquiry. Consequently, we have directed a number of our recommendations to CEPA.

The following chapters describe what we learned about SCC and how we used that knowledge to develop our recommendations.

Chapter Three

Understanding Stress Corrosion Cracking

3.0 Introduction

In this chapter, we discuss what we have learned about how SCC initiates and grows. We set out our understanding of environmentally assisted cracking and the differences between near-neutral pH SCC which is found in Canada and high pH SCC. We also explain what is known about the three conditions which are necessary for SCC to initiate and grow.

3.1 Environmentally assisted cracking

SCC is a form of "environmentally assisted cracking" or EAC. This is the generic term that describes all types of cracking in pipelines where the surrounding environment, the pipe material and stress act together to reduce the strength or load-carrying capacity of a pipe.

In a sense, the different types of EAC are the result of a chemistry problem and a physics problem working together. The specific circumstances under which each type will occur are unique. When steel comes into contact with water, the minerals and gases in the water at the pipe surface create cells that attack the steel. This chemical or electrochemical reaction is corrosion and, in other situations, would typically create general pipe wall thinning or pits in the steel. But stress is part of the EAC equation and, in some types of EAC, stress and corrosion work together to weaken the pipe.

Other types of EAC have also been found in other industries. Boilers have developed caustic cracking, nuclear reactor carbon steel coolant piping systems have developed stress corrosion cracking and stainless steel piping in ammonia units in chemical plants have cracked, as have down-hole pipes in sour oil wells.

3.2 Near-neutral pH and high pH SCC in pipelines

We know of two types of SCC that cause failures on pipelines. They are referred to as near-neutral pH and high pH SCC and the names refer to the degree to which the environment in contact with the pipe surface is acidic or alkaline.

The SCC on Canadian pipelines has all been of the near-neutral pH type, so our focus is on how that form of SCC develops. However, the conditions that produce near-neutral pH SCC are better understood if they can be compared with the conditions which produce high pH SCC. The following description of how high pH SCC starts and then

Close relations: other types of environmentally assisted cracking (EAC)

Some other examples of different types of EAC include corrosion fatigue, hydrogen-induced cracking (HIC) and hydrogen embrittlement. The following are examples of the effects of environment and loading which produce these types of cracking.

- A pipe in seawater with slowly applied cycles of loading will not crack due to stress corrosion cracking but it will develop corrosion fatigue cracks if enough cycles of loading are applied.
- A pipe in a carbonic acid environment (near-neutral pH), in the absence of an applied cathodic potential, will crack due to stress corrosion cracking when subjected to slowly applied cycles of loading, e.g., less than one cycle per day. If the loading frequency is increased to hundreds of load cycles per day, corrosion fatigue cracks can develop. If the loading frequency is increased further, fatigue cracks can develop since the time in contact with the environment is too short for the environment to have an effect. (The difference is in the amount of time the environment is in contact with the steel during the tensile loading portion of the cycle.)

pH facts…

Soil and water can be acidic, neutral or alkaline, and the degree of acidity or alkalinity is measured on a pH scale that ranges from 0 (most acidic) to 14 (most alkaline). Tap water is typically pH 7, which is neutral.

grows will provide a context for the discussion of near-neutral pH SCC which follows.

3.2.1 High pH SCC

Although pipelines are coated for protection against corrosion when they are put into the ground, there is always the risk that the steel pipe could become exposed to the surrounding environment. The pipe would then be vulnerable to corrosion. Since corrosion is an electrochemical reaction, an electric current is passed through the soil to the pipe to effectively prevent corrosion. This process of applying a voltage to the pipe through the soil gives the pipeline a cathodic potential and is referred to as cathodic protection.

High pH SCC occurs only in a relatively narrow cathodic potential range in the presence of a carbonate/ bicarbonate environment and at a pH greater than 9. In the cathodic potential range and environment required for high pH SCC, a protective film forms on the steel surface [1]. This film is a thin oxide layer that forms from the electrochemical reaction that takes place.

If the protective film on the pipe surface is not broken, SCC cannot start because the film acts as a barrier between the pipe surface and the environment. But if the steel is subjected to a strain that stretches the metal until it is permanently deformed, the film, being brittle, will crack and bare metal will be exposed to the environment.

Table 3.1
Characteristics of high pH and near-neutral pH SCC in pipelines

Factor	Near-neutral pH SCC (Non-classical)	High pH SCC (Classical)
Location	• 65 per cent occurred between the compressor station and the 1st downstream block valve (distances between valves are typically 16 to 30 km) • 12 per cent occurred between the 1st and 2nd valves • 5 per cent occurred between the 2nd and 3rd valves • 18 per cent occurred downstream of the third valve • SCC associated with specific terrain conditions, alternate wet-dry soils, and soils that tend to disbond or damage coatings	• Typically within 20 km downstream of compressor station • Number of failures falls markedly with increased distance from compressor and lower pipe temperature • SCC associated with specific terrain conditions, alternate wet-dry soils, and soils that tend to disbond or damage coatings
Temperature	• No apparent correlation with temperature of pipe • Appear to occur in the colder climates where CO_2 concentration in groundwater is higher	• Growth rate decreases exponentially with temperature decrease
Associated Electrolyte	• Dilute bicarbonate solution with a neutral pH in the range of 5.5 to 7.5	• Concentrated carbonate-bicarbonate solution with an alkaline pH greater than 9.3
Electrochemical Potential	• At free corrosion potential: -760 to -790 mV ($Cu/CuSO_4$) • Cathodic protection does not reach pipe surface at SCC sites	• -600 to -750 mV ($Cu/CuSO_4$) • Cathodic protection is effective to achieve these potentials
Crack Path and Morphology	• Primarily transgranular (across the steel grains) • Wide cracks with evidence of substantial corrosion of crack side wall	• Primarily intergranular (between the steel grains) • Narrow, tight cracks with no evidence of secondary corrosion of the crack wall

Source: Adapted from endnote [2]

This process of rupturing the film to expose the metal is what creates the opportunity for SCC to initiate.

The deforming type of strain described is called a "plastic" strain. Once the plastic strain decreases to an "elastic" level, a strain that does not permanently deform the pipe, the protective film forms over the newly exposed steel, re-establishing the protective barrier. Then crack growth stops. For a crack to start growing again, the film must be cracked by plastic strain deformation at the crack tip. This cyclical process shows that cracks can start and stop growing depending on the level of stress or strain on the steel. Since it takes time for the film to form, the cracks can grow only if the rate of plastic deformation occurs more quickly than the rate at which the film forms. Consequently, the strain rate, which is related to the rate at which the pressure in the pipe changes, is a condition that determines crack growth in high pH SCC. It is important to note that the level of stress or strain at a particular location on a pipe may differ from the level of stress or strain on the pipeline as a whole.

3.2.2 Near-neutral pH SCC

Research into high pH SCC has been in progress for more than 30 years; however, there are only about ten years of research into near-neutral pH SCC. Because of the differences between the two types of cracking, the research is generally not transferable. Consequently, additional knowledge must be developed about near-neutral pH SCC. The characteristics of near-neutral pH and high pH SCC are compared in Table 3.1.

Several researchers have established leadership in SCC research and some of these scientists made presentations to the Inquiry. Parkins cautioned that the way in which near-neutral pH SCC initiates and then develops is not yet completely understood, and so what we report here should be taken in that light [3]. In his submission, Parkins discussed how dissolution and hydrogen are believed to be factors in the growth of near-neutral pH SCC [4]:

> *We are far from having a reliable, quantifiable theory or model for near-neutral pH SCC. I have suggested that the mechanism of crack growth involves dissolution and the ingress of hydrogen into the steel, the hydrogen facilitating crack growth by promoting reduced ductility. While it is clear from evidence of corrosion on the sides of cracks, developed in service or laboratory tests, that dissolution occurs within crack enclaves, it is doubtful that growth can be accounted for entirely in terms of a dissolution process. That is because at high stresses or strains observed growth rates are markedly greater than can be accounted for by rates of dissolution in* [near-neutral] *pH environments. However, the evidence in support of hydrogen playing a role in the overall growth process is circumstantial rather than direct.*

Parkins [5] indicated that the factors contributing to the development of near-neutral pH cracking would appear to include the following:

1. Cracks are probably initiated at pits on the steel surface wherein a localized environment is generated that has a pH low enough to produce atomic hydrogen in the pit.
2. The presence of carbon dioxide in the groundwater assists in creating near-neutral pH levels.
3. Some of the discharged atomic hydrogen enters the steel, degrading the mechanical properties locally so that cracks are initiated or grown by a combination of dissolution and hydrogen-embrittlement.
4. Continuing anodic dissolution in the crack is necessary for crack growth, assisted by hydrogen entry into the steel.
5. The plastic stress level necessary to produce cracking may not be related solely to fracturing the embrittled steel. It may also contribute by rupturing the protective film, allowing hydrogen to reach and then penetrate the steel.

Thus, Parkins [6] is of the view that near-neutral pH SCC crack growth involves dissolution and hydrogen, and he is supported in that view by Leis [7], Wilmott and Jack [8], Lambert and Plumtree [9] and Beavers [10].

3.2.3 High pH versus near-neutral pH SCC crack characteristics

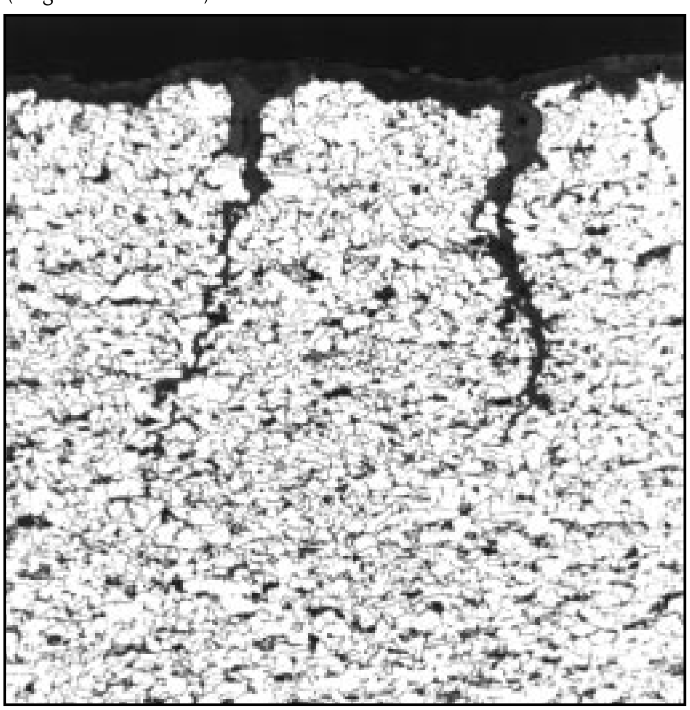
One difference between high pH and near-neutral pH SCC is the way in which the cracks grow. Figures 3.1 and 3.2 show metallographic sections through high and near-neutral pH SCC cracks respectively. High pH SCC generally produces intergranular cracking, where the cracks grow around or between the grains in the steel. These cracks are very tight, narrow cracks. The cracks generally produced by near-neutral pH SCC are different. They are generally transgranular, where the cracks follow a path across or through the grains. The side walls of the cracks corrode and the cracks appear much wider than high pH SCC cracks. However, the crack generally becomes narrower as the crack deepens.

The difference in the crack path (intergranular versus transgranular) is the result of the different effects of the environments and the susceptibility of the steel. In high pH SCC, the grain boundaries are more susceptible to dissolution than the grains themselves and so that is where the cracks form. Parkins showed that transgranular cracking can also occur in high pH SCC when the cracks become relatively deep or are subjected to relatively high stress levels or high fluctuating stresses [11]. The significance of this is that the presence of a transgranular crack by itself is not enough to be certain that a crack is near-neutral pH SCC.

Figure 3.1
Metallographic section high pH SCC
(Magnified 250 times)

Courtesy of R.J. Eiber

Figure 3.2
Metallographic section near-neutral pH SCC
(Magnified 250 times)



Courtesy of R.J. Eiber

3.3 The conditions for SCC

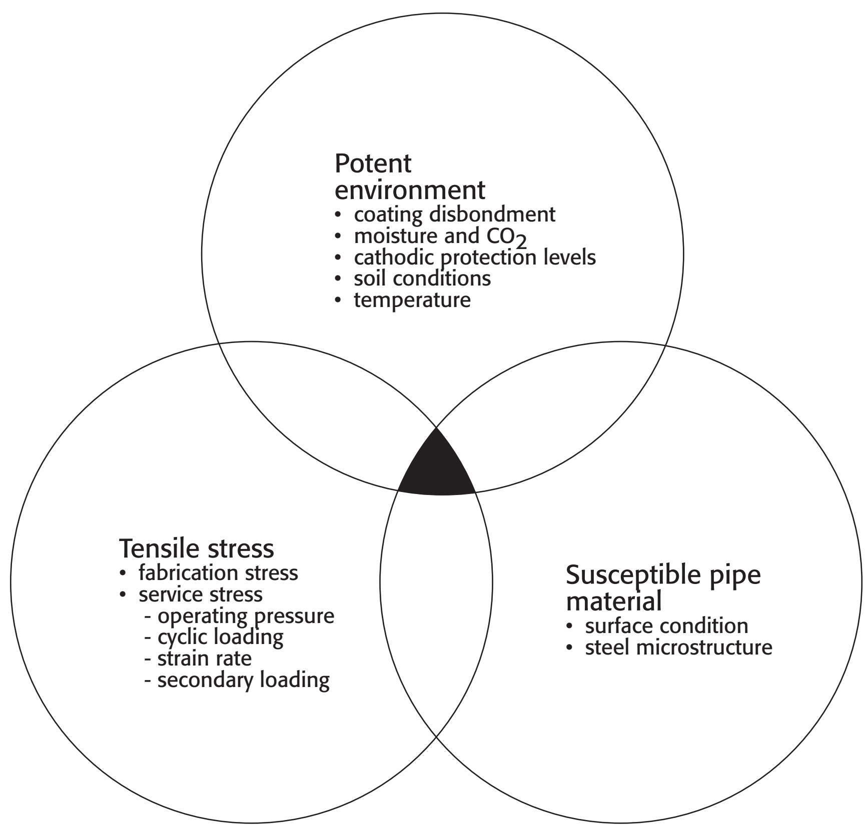
As we have noted, each type of EAC, including SCC, develops under its own unique and individual set of conditions. This Inquiry studied in detail the specific conditions in which near-neutral pH SCC developed in a specific type of pipeline related environment. We know that three conditions are necessary for stress corrosion cracking to occur:

- a potent environment at the pipe surface,
- a susceptible pipe material, and
- a tensile stress.

This concept is shown graphically in Figure 3.3.

The key point is that all three conditions must be present in order for cracking to occur. If any one of these three conditions can be eliminated or reduced to a point where cracking will not occur, then SCC can be prevented. For example, in many cases, if the environment is only mildly corrosive but there is no source of stress or susceptible pipe material, the corrosion will not be significant enough to affect the integrity of a pipeline. Similarly, if the environmental conditions are more corrosive and if there is a source of stress, but the metal pipe is well enough protected, SCC cannot initiate.

Figure 3.3
Three conditions necessary for SCC



We will now take a detailed look at the unique aspects of these three conditions that lead to the development of SCC.

3.4 Potent environment

The conditions at the pipe surface are referred to as the environment. This environment may be isolated from the surrounding soil by the pipe coating and the conditions at the pipe surface may be different from those in the surrounding soil. Laboratory research and field experience have given us considerable insights into the environment which gives rise to near-neutral pH SCC. Researchers have learned that the environment covers a range of chemical species that allow near-neutral pH SCC to develop. SCC has been found in environments with low concentrations of carbonic acid and bicarbonate ions with the presence of other species, including chloride, sulphate and nitrate ions. Since this range of environments all produce SCC, it can be expected that the environment found at SCC sites will vary [12].

The carbonic acid results from carbon dioxide (CO_2) in the soil combining with groundwater: the lower the groundwater temperature, the higher the solubility of CO_2; the higher the CO_2 level, the lower the pH, with the range being near-neutral, 5.5 to 7.5. The carbonic-acid environments measured in the field where SCC has been found have been relatively dilute and, therefore, not strongly corrosive [13].

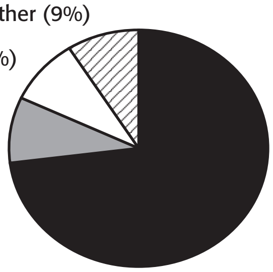
The environment for near-neutral pH SCC can only develop after damage to or disbondment of the pipe coating and in the absence of the cathodic current which is used to control corrosion. If the cathodic current reaches the pipe surface in the presence of groundwater with low levels of CO_2, a carbonate/bicarbonate environment will form with a pH in the range of 9 to 13 and near-neutral pH SCC will not occur. However, some types of pipe coating, when disbonded, act as a barrier to cathodic protection. Also, the high resistivity of the soil may prevent the cathodic current from reaching the pipe surface. In these instances, if groundwater and CO_2 are present at the pipe surface, a carbonic acid environment forms, with a pH in the range of 5.5 to 7.5, the range associated with near-neutral pH SCC.

In summary, the four factors controlling the formation of the potent environment for the initiation of near-neutral pH SCC are type and condition of coating, soil, temperature and cathodic current level.

3.4.1 Pipeline coating types

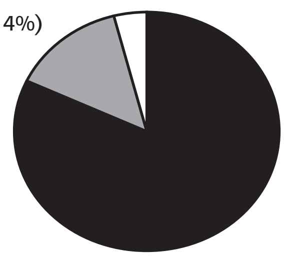
Over the years, pipelines have been protectively coated with several different materials and we have learned that the type of coating on the pipe has an effect on the formation of a near-neutral pH SCC environment. The reason is that the characteristics of the coating materials are different and one may be more prone than another to disbonding (where the coating comes away from the pipe but does not

Figure 3.4
Distribution of SCC failures with type of coating



Source: Endnote [14]

Figure 3.5
Distribution of SCC failures with year of pipe installation



Source: Endnote [14]

break) or to forming "holidays" (where there are breaks or gaps in the coating). While polyethylene tape was predominately used from the early 1960s to the early 1980s, a high percentage of the failures have occurred on pipelines coated with polyethylene tape and installed from 1968 to 1973 (Figures 3.4, 3.5). It is important to note that, to date, there have been no reported instances of SCC on pipe coated with either extruded polyethylene or fusion bonded epoxy (FBE)[14]. Some of these coatings have been in place for over 20 years.

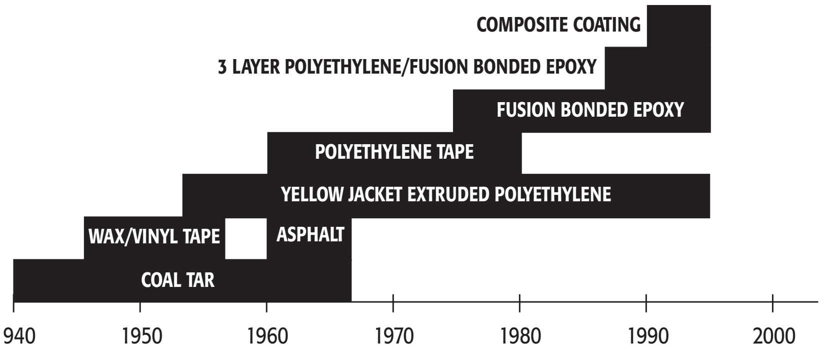
The types of coatings used in the industry have evolved over the years. Figure 3.7 provides an overview of the predominant pipe coating types used in Canada over the past 60 years. Some of these coatings continue to be applied to pipelines today.

- In the 1950s and 1960s, coal tar or asphalt coatings were commonly applied in the field. Occasionally, they were applied at the pipe mill in the 1970s and 1980s.
- In the mid-1950s, extruded polyethylene coatings applied at the mill were introduced. They have been used since that time, primarily on small diameter pipes.
- From the early 1960s to the early 1980s, polyethylene (PE) tape coatings, either single or double wrap, were field-applied (Figure 3.6). Since the mid-1980s, the tape-wrap system has been improved. Better bonding compounds (mastics) mean that the newer tapes are less likely to disbond at the pipe surface. Now, if there is any disbondment, the tape separates from the mastic. Since the mastic remains on the pipe surface, the pipe remains protected.

Figure 3.6
Tape wrapping machine

Courtesy of Petroleum Communication Foundation/NOVA

Figure 3.7
Overview of predominant pipe coatings in Canada



Source: Endnote [15]

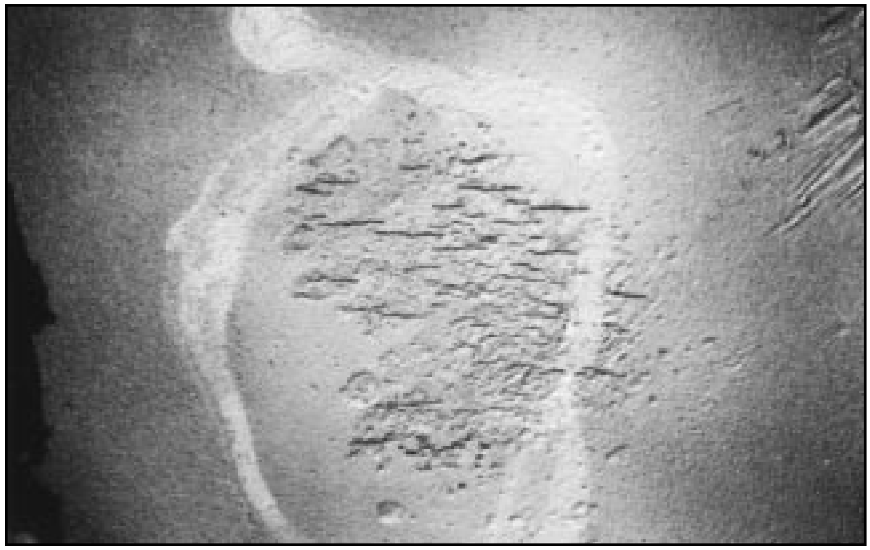
- In the early 1970s, mill-applied fusion bonded epoxy coatings were introduced and have been increasingly used on large diameter lines since that time. They are now the most commonly used type of coating [15].

Typically, coal tar, asphalt, extruded polyethylene coatings and polyethylene tape coatings were applied to pipe that had been wire brushed or scraped to remove loose dirt and rust. The FBE coated pipes were grit-blasted or sand-blasted before being coated. This removed most of the mill scale present on the pipe surface and improved bonding. For mill-applied coatings, the pipe ends were left bare and the girth welds which join the pipes together were coated in the field using a different material, typically, polyethylene tape, heat shrink sleeves or liquid epoxy. Characteristics of each of the main coating types are now discussed.

Asphalt and coal tar coating. These coatings are relatively thick at 2 to 4 mm and can be relatively brittle. Unless the pipe surface was adequately prepared, these coatings may have bonded poorly to the steel. Soil stresses tend to make these coatings prone to disbondment and holidays while a pipeline is in operation. When they disbond, these coatings tend to become saturated with moisture and conduct cathodic current in the disbonded area, thus protecting the pipe. Near-neutral pH SCC has occurred on pipes coated with asphalt or coal tar coatings only when the soil has been so highly resistive that the cathodic current has not been able to reach the pipe surface. On asphalt coated pipe, the SCC cracks have no preferential locations but may occur wherever the coating is disbonded or a holiday exists. SCC on asphalt coated pipes has a similar surface appearance to the colony of cracks in Figure 3.8.

Over-the-ditch polyethylene tape coating. These tapes are spirally wrapped around the pipe with an 18 to 50 mm overlap. These coatings are prone to disbondment because of tenting that occurs between the pipe surface and the tape along the ridge created by the longitudinal weld reinforcement (Figure 3.9). A second area of potential disbondment occurs where the tape is overlapped to achieve a bond

Figure 3.8
Colony of SCC cracks



Courtesy of R.J. Eiber

between successive wraps of tape. When polyethylene tapes disbond, they allow moisture to penetrate under the coating. Because of the high electrical insulating properties of the polyethylene tape and the long path under the disbonded tape, the cathodic current being applied through the soil cannot reach the pipe surface to prevent corrosion. Consequently, a potent environment may exist which will contribute to the formation of near-neutral pH SCC.

This coating type is a significant factor in the occurrence of SCC, as 73 per cent of failures caused by near-neutral pH SCC have occurred on polyethylene tape coated pipe (Figure 3.4). CEPA indicates that SCC has been found approximately four times as often on pipe coated with polyethylene tape as on asphalt and coal tar enamel coated pipe. The problems with polyethylene tapes are even more evident when coating types are compared for the average number of SCC colonies found per metre of pipe. Single-wrapped polyethylene tape coated pipe had five times as many SCC colonies per metre as asphalt/coal tar coated pipe. Double-wrapped polyethylene tape coated pipe had nine times as many colonies per metre as asphalt/coal tar coated pipe [16].

Figure 3.9 illustrates the regions where near-neutral pH SCC typically occurs on the exterior surface of a pipe coated with polyethylene tape and the types of crack patterns (longitudinal and circumferential) that occur. Figure 3.11 shows a photograph of cracks that formed on a polyethylene tape coated pipe in the tenting region of the double submerged arc weld (DSAW) and adjacent to it. The cracks tend to occur at or near the toe of the seam weld because stress is concentrated at this location and this is an area where groundwater has ease of access. Cracks also form in the body of the pipe in areas where

Figure 3.9
Areas of near-neutral pH SCC formation

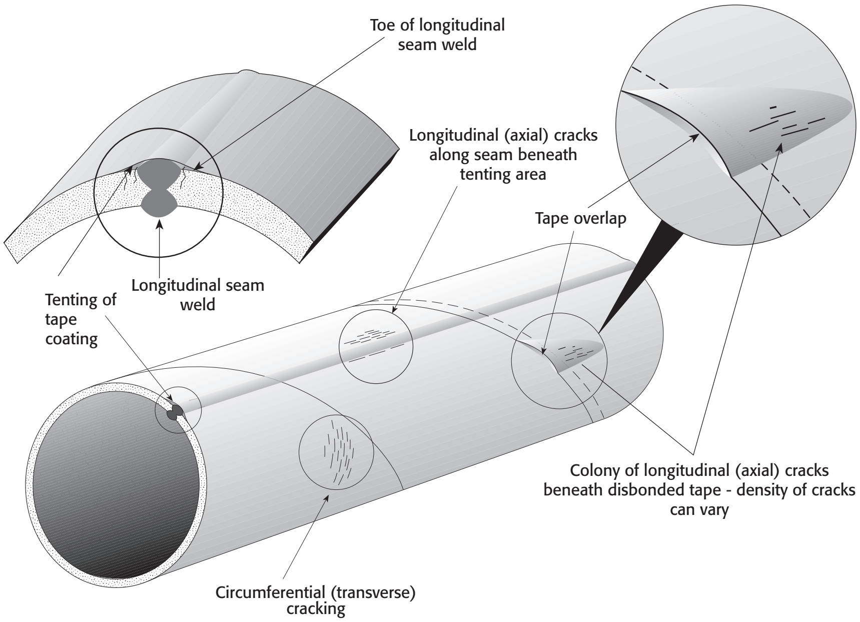


Figure 3.10
Polyethylene tape coating in poor condition due to wrinkling

the coating has been damaged (e.g., Figure 3.10) or where a disbond has formed along the spiral tape overlap, as shown in Figure 3.12. Since the cracks form only in areas where the coating is damaged or disbonded, they typically form in isolated "colonies" which contain a number of cracks. Figure 3.8 shows an isolated colony of cracks that formed in an area of polyethylene tape disbondment.

Figure 3.11
SCC cracks along and at the toe of longitudinal seam weld

Courtesy of R.J. Eiber

Figure 3.12
SCC cracks under spiral polyethylene tape overlap

Courtesy of R.J. Eiber

Fusion bonded epoxy coating. These coatings are generally resistant to disbonding. When they do disbond, they act like the asphalt coatings in that they become saturated with moisture and allow the cathodic protection current to reach the pipe, preventing the formation of the near-neutral pH SCC environment. No SCC has been found under these coatings to date.

Extruded polyethylene coating. These coatings have been used primarily on smaller diameter pipes, those less than 508 millimetres (20 inches) in diameter. The coatings are relatively thick and tough, making it difficult for holidays to develop. Even punctures from mechanical damage or handling are unlikely. No SCC has been found under these coatings.

3.4.2 Soils

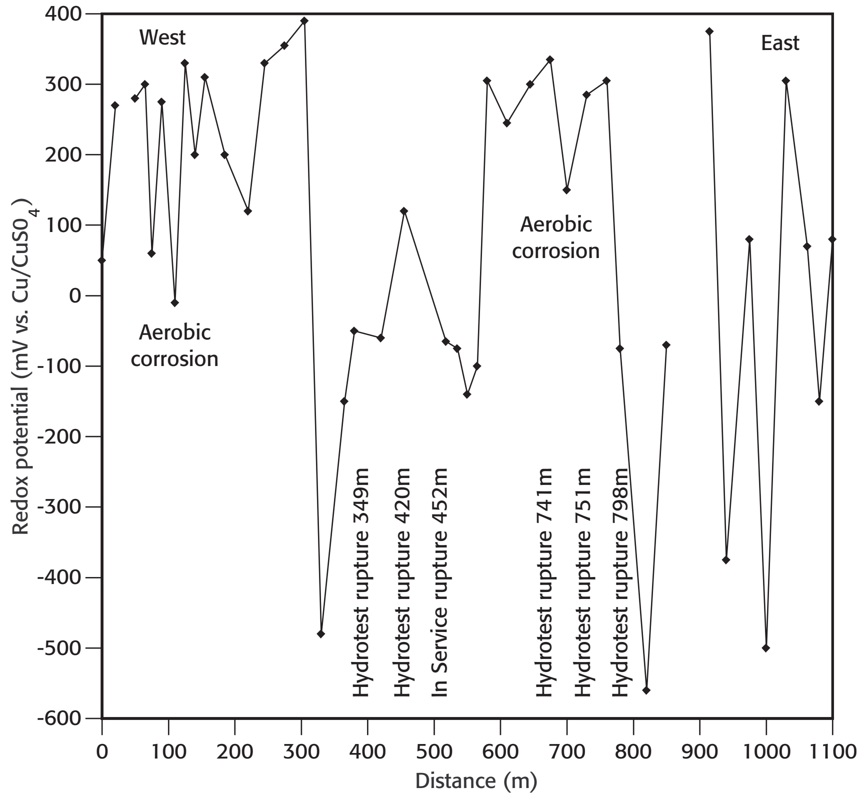
There are several factors relating to soils that influence the formation of the near-neutral pH SCC environment. These are soil type, drainage, topography, CO_2, temperature, electrical conductivity and the use of inhibitors.

Soil type. The soil type affects the performance of a coating, particularly polyethylene tape. Bluish-coloured clays hold moisture and create soil stresses which contribute to the disbondment of polyethylene tape coatings, setting up one of the conditions necessary for near-neutral pH SCC. Rocks can create holidays in coatings, allowing groundwater to come in contact with the pipe surface.

Soil drainage. The amount of moisture in the soil also affects the formation of a near-neutral pH SCC environment. Poorly drained or imperfectly drained soils provide a supply of moisture. Areas that have a constantly-high moisture level do not seem to be as likely to produce near-neutral pH SCC environments as those where the moisture level varies. These drainage types also determine whether the soils are reducing (anaerobic) or oxidizing (aerobic). An anaerobic soil is believed to be necessary to create the near-neutral pH SCC environment [17]. In anaerobic soil conditions, sulphate reducing bacteria (SRB) may form and reduce sulphate in the soil to sulphide. When water reaches the pipe surface and the corrosion reaction begins, atomic hydrogen is created. It needs oxygen to become molecular or gaseous hydrogen, but the sulphide is a poison that prevents the atomic hydrogen from forming molecular hydrogen. In molecular form, the hydrogen would not be able to penetrate the pipe and would leave the pipe surface. Instead, the sulphide allows the atomic hydrogen to penetrate the pipe. As Parkins pointed out, the effect of the hydrogen is to embrittle the steel at the tip of a crack, making it easier for a crack to grow. The contribution of anaerobic bacteria to near-neutral pH SCC has been evaluated but no conclusion about their role has been reached [18].

The soil's oxidizing-reducing ability can be measured and is referred to as its redox potential. The redox potential indicates whether a soil is aerobic (positive potential) or anaerobic (negative potential). The question this raises is whether the redox potential could be another soil characteristic that identifies SCC-susceptible soil areas. Wilmott published a paper [19] in 1996 in which negative measurements of the soil's redox potential (anaerobic soil) generally appeared to correlate with the occurrence of near-neutral pH SCC on the pipeline segment. Figure 3.13 plots the redox potential against distance and shows a similar outcome: that the in-service and test failures occurred where

Figure 3.13
Virginia Hills, Alberta 1.1 km pipe replacement section: variation of soil redox potential with distance



Source: Endnote [19]

the potential is negative (anaerobic). However, the correlation is not precise since at distances of 741 and 751 metres the redox potential is positive, indicating aerobic soil conditions. Yet failures due to near-neutral pH SCC still occurred at those distances under hydrostatic retesting. These results are interesting and this is an area where additional research could provide more answers.

Soil topography. Closely allied with soil drainage is the topography of the land. Near-neutral pH SCC appears to be associated with depressions in the landscape, at the base of hills or near streams, where the groundwater either flows along the pipeline or across it. Flowing water may help to maintain the near-neutral pH environment by supplying additional CO_2 to the electrolytic solution in the disbonded area at the pipe surface.

CO_2 level and soil/pipe temperature. While high pH SCC growth depends very much on soil or pipe temperature (they are generally the same along a pipeline), laboratory and field data have not shown a similar correlation for near-neutral pH SCC. Parkins carried out slow strain rate tests but the results showed no significant differences for crack growth rates at temperatures of 5ºC and 45ºC [20].

On natural gas transmission pipelines, the temperature of the gas and the pipe is as high as 40ºC on leaving a compressor station and it cools as the gas moves downstream. On TransCanada's system, only one-third of its service and hydrostatic retest failures have occurred within 16 km downstream of a compressor station, where the temperature of the gas is high. In field excavations carried out on the TransCanada and NGTL systems, near-neutral SCC has been found more than 30 km downstream of compressor stations where the temperature of the gas would be lower. Near-neutral pH SCC has also been found on the NGTL system at a location where the soil temperature surrounding the pipe was in the region of 10ºC or lower [21].

Beavers suggests that the absence of a correlation between higher soil temperatures and near-neutral pH SCC may result from the increasing solubility of CO_2 in water at lower temperatures [22]. As more CO_2 dissolves in groundwater, the ability of the cathodic protection system to raise the pH at the pipe surface is greatly reduced. If this idea is correct, it could mean that the environment for near-neutral pH SCC is more likely to develop at lower temperatures because of the higher potential concentration of CO_2. Beavers suggests a higher concentration of CO_2 may be one reason why the near-neutral pH environments appear to form in the colder climates, such as those in Canada and the former Soviet Union. This is a possibility that has not been completely explored and additional research may provide us with a better understanding of the factors controlling the formation of the near-neutral pH SCC environment.

Cathodic protection current. Near-neutral pH SCC develops where cathodic protection current cannot penetrate under or through the coating to reach the steel pipe. For polyethylene tape coated pipe, the cathodic protection cannot reach further than a few centimetres from the tenting or holiday in the coating because of the shielding effects of the disbonded tape. It might seem reasonable to try increasing the cathodic protection current with the hope that it might reach further into the disbonded area. However, that is impractical since these areas can be a metre long or more. In these circumstances, a significant portion of the exposed pipe is susceptible to SCC. As a result, it does not appear that higher cathodic protection potentials will help prevent the growth of SCC on tape coated pipelines. In fact, CEPA and NRTC have suggested that a higher cathodic protection current could lead to more disbondment on tape coated systems. However, NRTC has considered another alternative. Preliminary studies by NRTC on pulsed cathodic protection indicate that pulsing can penetrate more deeply into a disbonded area than can conventional cathodic protection systems [23]. Depending on the size of the disbonded area, pulsed cathodic protection may help to control near-neutral pH SCC. This is also an area that should be researched further.

Steel properties…

Within a certain range of loads, steel has an "elastic" property which allows it to deform (extend) under load and then return to its original shape when the load is removed. The limit of load which keeps steel in its elastic range is termed the "elastic limit" (proportional limit).

Beyond the elastic limit, steel begins to deform permanently or "plastically" at increasing rates under load to a point called the "yield strength" which is the maximum limit of useable stress. Pipelines are designed to maintain loads below a "specified minimum yield strength" (SMYS).

If loading continues beyond the yield point, steel will continue to deform and eventually break apart or fracture. The fracture is termed "ductile" if the steel tears apart slowly and stretches (plastic deformation). In contrast, a failure is termed "brittle" if the steel breaks apart quickly with little sign of deformation. In pipeline terms, brittle fracture in a natural gas pipeline can result in a pipe rupture which extends over a considerable distance (hundreds of metres) whereas a ductile failure is usually contained within two pipe joints (25 metres). Modern pipeline steels have the ductile properties to prevent a brittle type of failure.

On asphalt coated pipelines, near-neutral pH SCC occurs in sandy well-drained soils where adequate levels of cathodic protection are difficult to achieve because there is little moisture to help conduct the current through the soil. This is an area where research may provide alternative ways to drive the cathodic current though high-resistivity soil.

Inhibitors. Researchers studying high pH SCC are considering whether inhibitors could be added to soils or coatings to prevent high pH SCC. However, no studies have been conducted to consider a similar possibility for preventing near-neutral pH SCC from initiating. Parkins stated [24]:

> *I am not aware of any work relating to the incorporation of inhibitors into organic coatings to control* [near-neutral] *pH SCC, although such studies have been conducted in relation to the high pH form. That work showed that sodium chromate or phosphate were capable of inhibiting intergranular cracking when present in sufficient amounts and it would be surprising if similar inhibitive substances could not be found for* [near-neutral] *pH SCC.*

What the field studies relating to high pH SCC showed was that the inhibitors – chromates, phosphates and silicates – leached out of the soil within a few years and so the declining levels of the inhibitors limited their effectiveness to a relatively short time [25][26].

3.5 Susceptible pipe

In addition to a potent environment, a susceptible pipe material is another necessary condition in the development of near-neutral pH SCC. In this regard, the data from pipeline failures caused by SCC showed that near-neutral pH SCC had developed on a wide variety of pipe. Pipe failures occurred on pipe in which diameters ranged from 114 to 1067 mm, wall thicknesses ranged from 3.2 to 9.4 mm and grades varied from 241 MPa (35 ksi) to 448 MPa (65 ksi). Both electric resistance welded (ERW) and DSAW pipe were involved in SCC-related failures.

Researchers and scientists have considered a number of pipe characteristics and qualities to determine if they are possibly related to the susceptibility of pipe to near-neutral pH SCC. These factors include the pipe manufacturing process, type of steel, grade of steel, cleanliness of the steel (presence or absence of impurities or inclusions), steel composition, plastic deformation characteristics of the steel (cyclic-softening characteristics), steel temperature and pipe surface condition.

3.5.1 Pipe manufacture

With one exception, near-neutral pH SCC does not appear to be associated with a particular pipe manufacturing method or manufacturer. The exception is the ERW longitudinal seam pipe manufactured in the

1950s by Youngstown Sheet and Tube (Youngstown) which was used on the TransCanada system in southern Ontario [27]. The weld seam of this pipe seems to have a lower resistance to near-neutral pH SCC than the base metal. The reason for this lower resistance of the weld area is unknown at this time but may be related to the low fracture toughness of this region, pits and arc burns associated with this manufacturer's ERW weld or a higher-than-normal residual stress [28]. It should be noted that TransCanada has implemented a special mitigative program to replace Youngstown pipe in close proximity to dwellings and to hydrostatically retest the Youngstown pipe every four years.

Beavers [29], in examining grade 448 MPa (65 ksi) samples taken from the TransCanada system, noted that the coarse-grained heat-affected zone (CGHAZ) adjacent to the DSAW is significantly more susceptible to cracking than the base material in the near-neutral pH environment. The average crack velocities are about 30 per cent higher in the CGHAZ than in the base metal. Whether this is an isolated condition on the TransCanada pipe or whether all CGHAZs will exhibit greater susceptibility is unknown and is an area for further investigation.

3.5.2 Pipe yield strength

No one has conducted a detailed assessment of the susceptibility of different steels to the initiation and growth of near-neutral pH SCC. Steel is often referred to by its grade which is linked to its yield strength. Pipe grades from 241 MPa (35 ksi) to 483 MPa (70 ksi) from a range of manufacturers have been found to be susceptible to near-neutral pH SCC. Researchers studying high pH SCC have found no correlation between the range of mechanical strengths observed in failed pipes and SCC susceptibility [30]. It is likely that, as research into near-neutral pH SCC is carried out, the same conclusion will be drawn since plasticity on the pipe surface or at a crack tip is the primary factor that causes SCC initiation. Higher strength steels may be more susceptible to SCC and/or hydrogen embrittlement which might make the SCC problem worse. It is known that if a higher strength pipe is substituted for a lower strength pipe with the same diameter and operating pressure, the critical flaw tolerance of the pipe will decrease due to the reduced wall thickness.

3.5.3 Plastic deformation characteristics

Localized microplastic deformation (permanent elongation) is necessary for the initiation and growth of near-neutral pH SCC cracks. Consequently, the conditions that produce localized microplasticity (low plastic strain or deformation levels in local areas) either on the pipe surface or at a crack tip are necessary for SCC crack initiation or growth. Normally, the strains that would produce this localized microplastic deformation do not occur at stress levels below the proportional limit of the steel. In most line pipes, the proportional limit is in the range of 85 to 95 per cent of the yield stress of the steel. However, the proportional limit may increase almost to the yield stress on pipelines that have been subjected to high-pressure hydrostatic retests. Consequently, high-pressure hydrostatic retests may be beneficial in making a pipe more resistant to SCC.

Two situations cause localized microplastic deformation at stress levels below the proportional limit of the steel. In one situation, the surface layer of the pipe wall thickness can deform before the bulk of the wall thickness [31] and, secondly, cyclic-loading can cause steels to exhibit microplastic strains at nominal stress levels where plastic strains would not be expected [32]. Leis has shown that the surface layer of a pipe can plastically deform more easily than the bulk of the material beneath it. Since the outside surface of the wall thickness is a free surface (a surface with one side not constrained by metal, just air), it can plastically deform at lower stress levels than the mid-portion of the wall thickness. This suggests that it is possible to initiate a crack because of pipe surface plasticity. At lower stress levels, the crack may grow until it reaches a depth where microplasticity can no longer occur because of the change in the stress state in the interior of the pipe wall thickness compared to the surface layer and the crack growth stops. At higher stress levels, the crack may continue to grow to the point where the pipe fails.

Cyclic-softening is a phenomenon in which the application of stress cycles or pressure cycles at maximum stress levels below the yield stress causes the steel to exhibit local microplastic deformation (strains) after a period of load cycles. The steel may then behave elastically for a number of cycles and then again exhibit plastic deformation for a number of load cycles. It is not known how many of these regions of plastic strains will be exhibited by a steel. However, the phenomenon has been exhibited by pipe steels of the type involved in the near-neutral pH SCC failures [33]. This partially explains why it takes a number of years of service before an SCC crack initiates. Basically, the steel has to be subjected to enough pressure cycles that it softens to the point where microplastic strains are created on the pipe surface.

Leis is of the view that the propensity for cyclic-softening is a function of the steel's microstructure. Limited research suggests that bainitic microstructures generally have less tendency to soften than the ferrite-pearlite microstructures of pipe that is currently in service.

The procedure for changing the cyclic-softening characteristics of an existing pipeline steel is unknown. It has been suggested that it might be possible to modify the softening characteristics through high pressure hydrostatic retests but currently no information is available to indicate whether this is feasible. Research is incomplete with regard to the cyclic softening behaviour of pipe steels.

3.5.4 Steel cleanliness

Surkov reports that a relationship has been observed between susceptibility to SCC and the length of non-metallic inclusions in the steel (particles of foreign material such as manganese sulfides) [34]. A threshold for crack initiation was found which indicated that if the length of surface defects which are governed by the length of non-metallic inclusions were smaller than 200-250 μm, longitudinal cracks would not form.

CANMET conducted limited research into inclusion length [35]. It took samples from five pipes with significant cracking and five samples with non-significant cracking and examined inclusion lengths. It concluded that a difference may exist between the average length of "light or thin" inclusions found in "cracked" and "uncracked" samples, with the uncracked pipes having longer inclusions than the cracked samples. The effect of material properties, including the role of non-metallic inclusions on the initiation of SCC, will be studied in a research program initiated by CEPA in the summer of 1996.

The British Gas in-line inspection tool results have indicated that, in TransCanada pipe that has experienced SCC, there is a higher number of non-metallic inclusions at the longitudinal weld seam (the original edge of the plate) than in the body of the pipe. This may partially explain why cracks tend to be found near the seam weld.

3.5.5 Steel composition

No studies have been conducted to look for a relationship between steel composition and near-neutral pH SCC susceptibility. However, studies have been conducted on steel alloys to evaluate its resistance to high pH SCC. The results showed that adding chromium, nickel and molybdenum to steel in amounts of between two to six per cent improved the resistance to high pH SCC. However, additions at such high levels made the steel prohibitively expensive to produce [36]. This could be another area for further research.

3.5.6 Pipe surface conditions

Parkins performed a number of cyclic load crack initiation experiments and found that the surface condition of the pipe was important in contributing to the initiation [37]:

> *In all of my work involving cyclic loading one of the test surfaces corresponded to the outer surface of the pipe from which the specimens were cut, that surface having been water blasted after removal of the pipe from the ground. The opposite side of the specimen was carefully polished and that surface very rarely produced any indications of crack initiation, and certainly not of growth beyond 20 μm, while when deeper cracks were produced they invariably were from*

the surface corresponding to the outer surface of the pipe. That outer surface was covered with very shallow, overlapping pits, although the water blasting had removed most of any corrosion products that probably were present when the pipe was excavated. Those pits would give some small degree of stress concentration, although I doubt that provides a full explanation for the different cracking propensities of the outer pipe and polished surfaces. More probable is it that pits provide a means of localizing composition and pH changes from the bulk solution, a phenomenon well known to occur with pits and other geometrical discontinuities in the presence of some environments.

Parkins' laboratory data suggest that at stress levels above the yield stress, the threshold stress (the point at which cracks would initiate and grow to failure) on a smooth, clean surface is different than on a surface similar to that of a pipe after years of service. Only in the presence of pits could he initiate cracks that would continue to grow (Figure 3.14).

The presence of mill scale on the pipe surface has been found to contribute to the formation of high pH SCC and would be expected to be a factor in near-neutral pH SCC as well. This is another area where the research is not complete.

3.5.7 Pipe temperature

Because soil temperature and pipe temperature are considered to be the same, pipe temperature was included in an earlier discussion. (See Section 3.4.2, CO_2 level and soil/pipe temperature.)

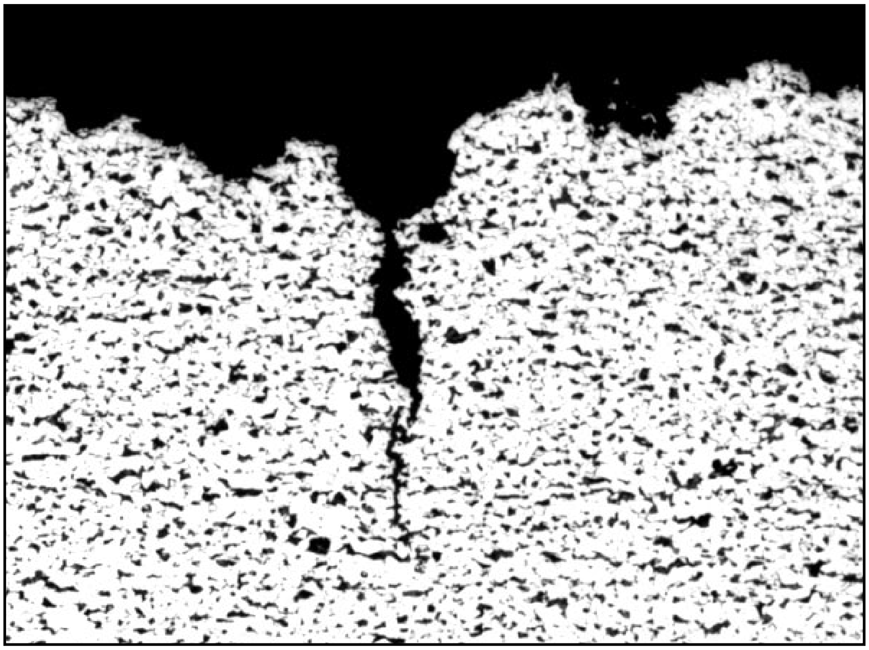
3.6 Stress

As noted in Section 2.1, the issue of a pipeline's internal pressure and its effect on SCC was raised by the TSB after the 1991 and 1992 incidents on the TransCanada system. Considerable research has been conducted since that time and in ongoing. A summary of the evidence and our conclusions follow.

3.6.1 Stresses in pipelines

Stress is the "load" per unit area within the pipe wall. A buried pipeline is subjected to stress of different types and from different sources. The pipeline's contents are under pressure and that is normally the greatest source of stress on the pipe wall. The soil that surrounds the pipe can move and is another source of stress. Pipe manufacturing processes, such as welding, can create stresses which are termed "residual" stresses. These are just a few examples. We will be discussing these and other sources of stress.

Figure 3.14
SCC crack formation at base of corrosion pit
(Magnified 150 times)

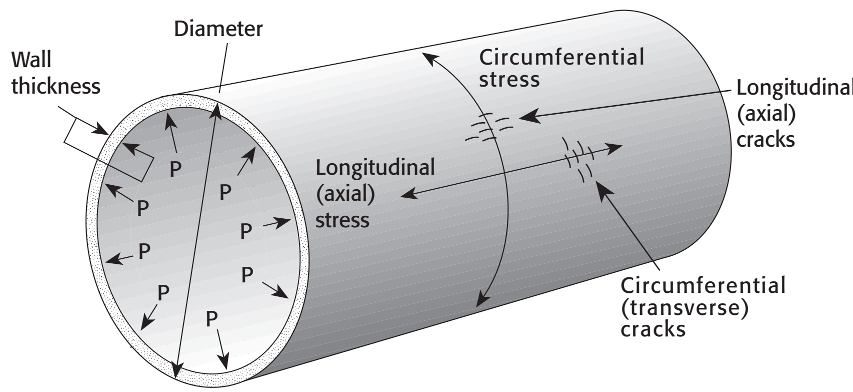


Courtesy of R.J. Eiber

The stresses in a pipe exist in two directions: around the pipe's circumference (referred to as circumferential stress) and lengthwise along the axis of the pipe (referred to as longitudinal or axial stress). Cracks occur perpendicular to the direction of the stress. Longitudinal (axial) cracks are found in areas of high circumferential stress and circumferential (transverse) cracks are found in areas of high axial stress (Figure 3.15).

- Circumferential stress in the pipe has several sources:
  1) circumferential stress due to internal operating pressure (hoop stress), usually the highest stress component in the pipe;
  2) residual stress in the pipe created during pipe manufacture;
  3) bending stresses that result when an oval or out-of-round pipe is subjected to internal pressure;
  4) local stresses at the edge of double-submerged arc welds or associated with mechanical gouges, corrosion pits and other areas where stress is concentrated;
  5) secondary stresses that may cause the pipe to go out-of-round, such as soil settlement or land slides; and
  6) stresses due to temperature differences through the thickness of the pipe wall.

Figure 3.15
Stresses in pipelines



P = Pressure

- Longitudinal (axial) stress in the pipe also has several sources:
    1) internal operating pressure (the operating pressure causes a longitudinal stress which is one-third to one-half the circumferential stress);
    2) secondary stresses that can bend the pipe and introduce high longitudinal stresses, such as soil settlement or landslides; and
    3) stresses due to temperature changes along the axis of the pipeline.

3.6.2 Stress in pipe during operation

The stress at any point in the pipe steel is the combined effect of all forms of circumferential and longitudinal stresses. In this section, each of these components will be defined and their influence discussed.

Internal operating pressure. Pipelines operate at various pressures. Typical large-diameter transmission pipelines operate at maximum pressures up to 8 700 kPa (1,260 psi). The circumferential stress caused by the operating pressure (P), also termed hoop stress (s), is affected by the diameter of the pipe (D) and the wall thickness (t) and can be calculated by the following mathematical expression referred to as Barlow's formula:

$$s = \frac{P\ D}{\ }$$

Since the internal operating pressure is usually the largest contributor to stress, it is common in the industry to express the stress in the pipe wall in terms of the hoop stress as calculated by Barlow's formula as a percentage of the specified minimum yield strength (SMYS) of the pipe steel. However, manufacturers generally produce pipe which has an actual yield strength which is higher than the SMYS. The actual yield strength can be 10 to 30 per cent higher than the SMYS. Therefore a pipeline that is operating at 72 per cent SMYS may only reach 60 per cent of the actual yield strength of the pipe.

The CSA Z662 standard sets the maximum allowable hoop stress depending on where the pipeline is located and the surrounding dwelling density. The standard sets out four class locations based on the dwelling density. The Class 1 location is generally a sparsely inhabited region or rural area. To be classified as a Class 1 location, there must be ten or fewer dwellings within an area extending 200 m on each side of the pipeline and running any continuous 1.6 km distance along the pipeline. On natural gas pipelines, the maximum allowable hoop or operating stress ranges from 80 to 44 per cent SMYS depending on the density of dwellings (Table 3.2). For example, 80 per cent SMYS is the maximum hoop stress allowed in a Class 1 location. The maximum allowable hoop stress governs the wall thickness of the pipe for a given grade (SMYS). For gas pipelines and pipelines which carry high vapour pressure (HVP) products such as propane, the maximum allowable hoop stress as a percentage of material strength decreases in populated areas and near roads.

Currently, regulations in many other countries limit the maximum hoop stress to 72 per cent SMYS [38]. There are a few pipelines in the U.S. that operated at higher stress levels before the U.S. Department of Transportation issued Part 192 of the Code of Federal Regulations in 1968. These pipelines continue to operate at stress levels up to 85 per cent SMYS under a grandfather clause to the existing regulations. In the Australian Code, AS 2885, there is a provision for stress levels over 72 per cent SMYS, but the complete line must be tested at a pressure greater than 100 per cent SMYS before it can operate above 72 per cent

Table 3.2
Maximum allowable operating stress in various class locations(1)

Class Location(2)	Description(3)	Maximum Operating Stress(4) (% of SMYS)			
		Natural Gas	Sour Gas	HVP	LVP
1	< 10 dwellings	80	72	80	80
2	10 - 46 dwellings or designated areas	72	60	64	80
3	> 46 dwellings	56	50	64	80
4	buildings 4 storeys or more	44	40	64	80

1 excerpt from CSA Z662-94 Oil & Gas Pipeline Systems
2 based upon a class location area which extends 200 m on both sides of the centre line of any continuous 1.6 km length of pipeline
3 Z662-94 clause 4.3.2 contains full description
4 maximum operating stress may be lower due to the hydrostatic testing pressure and other factors such as proximity to roads, railways, etc.

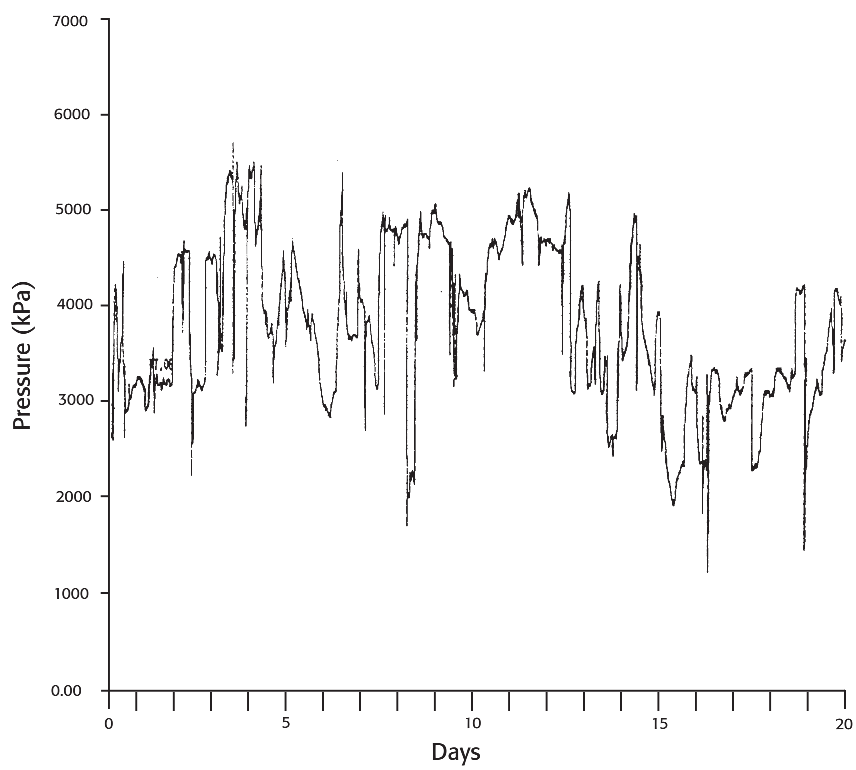
SMYS. However, to our knowledge, there are no lines in Australia operating in excess of 72 per cent SMYS.

The internal pressure in a pipeline continually changes or fluctuates. In a gas line it is affected by the rate at which the gas is injected into the system and withdrawn by downstream deliveries. Often these rates are not controllable by the pipeline operator. In liquid pipelines the pressure fluctuates more widely since it is affected by the turning on and off of pumps and any changes in the density of the fluid being pumped.

Figure 3.16 presents a 20-day pressure profile for a liquids pipeline. The pressure profile for a gas pipeline would not fluctuate as much and the fluctuation would occur over longer periods of time. As Figure 3.16 shows, the maximum pressures vary throughout the period, depending on the flow rate. In order to fully characterize the operating pressure of a pipeline and, therefore, stress, three factors have to be considered:

- the pressure level or maximum operating pressure applied;
- the range in which the pressure fluctuates (which in Figure 3.16 is from 1 250 kPa (181 psi) to about 5 750 kPa (833 psi) and the minimum pressure is 22 per cent of the maximum operating pressure); and

Figure 3.16
A 20-day pressure profile for a liquids pipeline



Source: Adapted from endnote [39]

- the rate of the pressure changes (almost instant change in some cases, or change over several days, in others).

Typically, on gas pipelines, the minimum pressure is in the range of 85 per cent of the maximum operating pressure. Stress levels in pipelines therefore fluctuate daily, weekly, monthly and yearly. The stress fluctuation is commonly referred to in terms of an R-ratio, which is the ratio of the minimum to the maximum stress in a circumferential direction.

Residual stress. When flat steel plate is formed into pipe, "residual stresses" are introduced into the pipe. The level of residual stress depends on the manufacturing process used to produce the pipe. For example, DSAW pipe is rolled into a tube, welded lengthwise and then pressurized with water to expand the pipe and make it round. This expansion process reduces the residual stress in the pipe. By contrast, ERW pipes and small diameter flash-welded pipes (typically less than 508 mm in diameter) are generally not expanded and so they can have higher residual stress levels. Seamless pipe (normally small diameter pipe), because it is hot-formed, receives the equivalent of a thermal stress relief and the residual stress tends to be relatively low. The residual stress in a pipe can also be reduced by the application of a high-pressure hydrostatic test before being placed in service. The higher the test pressure, 105 to 110 per cent SMYS, for example, the lower the residual stress.

Parkins stated that [40]:

> *It is known that operating pipelines can contain residual stresses that may be at least as high as about 25 per cent of the yield stress of the material and those may influence cracking behaviour, not least in view of the fact that the vast majority of SCC failures in a wide variety of materials and environments involved with various engineering structures* [other than pipelines] *are due to residual rather than operating stresses.*

There have been no systematic studies of residual stress levels in relation to SCC in line pipe or on the distribution of the residual stresses in the axial or circumferential direction. Based on the statement by Parkins, however, and the information obtained from the Camrose Pipe Company [41], the production process may introduce maximum residual stresses up to 25 per cent of the yield stress in the finished pipe.

Researchers are still uncertain about the influence of residual stresses on the initiation and growth of near-neutral pH SCC. But it is known that in other industries, residual stress can elevate stress levels in localized areas to the point where SCC is initiated. Consequently, it seems reasonable to think that residual stress should be minimized. It may be possible to thermally stress-relieve the pipe when it is being manufactured to reduce the residual stress level. This approach would have to be examined to make sure the fracture toughness or yield strength properties of the steel pipe would not be adversely affected. Alternatively, increased expansion during pipe manufacture might be used to mechanically reduce the residual stress. High-pressure hydrostatic tests will reduce residual stress on existing pipelines but the residual stresses cannot be completely eliminated.

Bending or out-of-roundness stress. Another factor that affects the circumferential stress level in a pipe is the roundness of the pipe. If a pipe is out-of-round, local bending stresses result when internal pressure forces the pipe to become round. This creates a bending stress through the pipe wall thickness and raises the hoop pressure stress on the outer pipe surface. In forming DSAW pipe, the longitudinal edges of the pipe are formed or crimped before they are welded together. If the pipe edges are not accurately formed or are offset radially from each other after welding, localized bending stresses are created, which add to the hoop pressure stresses.

Local stress intensifiers on the pipe surface. Any irregularity in the surface of the pipe can be a source of stress concentration. Where surface damage, dents or corrosion pits are found, stress levels in the circumferential and axial directions on the surface of the pipe are higher than on the rest of the pipe. Surface damage such as gouges, grooves or dents can be caused by construction equipment or improper backfill material. Pits can be produced by carbonic acid, a weak acid that is the near-neutral pH SCC electrolyte. Once a pit is initiated, it will tend to further acidify the environment and increase the local stress. The pipe wall thickness may also be reduced by corrosion or a gouge which will locally elevate the stress in the pipe wall and contribute to the conditions that allow SCC to initiate.

Secondary stresses. These stresses can occur in either the circumferential or longitudinal direction. They are most commonly caused by soil movement such as land slides and settlement or by the physical weight of the soil above the pipe (overburden). The level of these stresses is generally unknown and difficult to predict; however, depending on soil movement, they can be quite low or they can be high enough to cause the pipe to fail.

Temperature stresses. Temperature differences through the pipe wall thickness can cause localized circumferential bending stresses. These stresses are generally not a problem on pipelines, as the pipe wall is thin enough that there is no difference in temperature between the outer surface and the bulk, or thickness, of the pipe.

Longitudinal (axial) stresses. In addition to circumferential stress, pipelines in operation experience stress which acts in the axial direction.

The pressure of the contents in the pipe also causes a stress in the axial direction of a pipeline which is a percentage of the hoop stress.

For example, when a pipeline is completely buried and restrained from longitudinal movement by the soil, the axial stress is 28 per cent of the hoop stress. When the pipeline is not completely restrained against longitudinal movement, the axial stress can be as high as 50 per cent of the hoop stress.

Temperature changes along the length of a line can cause axial temperature stresses, but again, these tend to be minor.

3.6.3 Field experience: the effect of stress

The effects of these types of pipeline stresses became clear when reviewing the field data gathered at the time of each pipeline failure. Of the 22 service failures that have occurred on pipelines in Canada, 16 of these failures (73 per cent) involved axial cracks, indicating that the circumferential stresses controlled the failure. At the time of the failures, the hoop stresses varied between 46 and 77 per cent of the pipe's SMYS. The remaining six failures involved circumferential (transverse) cracks indicating that the axial stress controlled those failures.

In all but one of the 16 failures, external factors increased the stress levels in the localized areas where the SCC was found. Corrosion, gouges or stress concentrations from the toe of the weld seam raised the local stress above the hoop stress levels derived from Barlow's formula [42]. Consequently, the level of stress that was actually experienced by the pipe and caused the failure is not known.

The six circumferential (transverse) crack failures occurred at hoop stress levels of 53 to 67 per cent SMYS but these values do not help to explain the failures, since as discussed above, the hoop stress is parallel to the crack direction. The longitudinal stress, which is perpendicular to a circumferential crack, was responsible for these failures. At the time of failure, the longitudinal stress caused by soil movement or secondary stresses was unknown but it was likely the predominant stress.

While none of CEPA's member companies have found "significant" SCC in Class 2 and 3 pipeline locations, they did acknowledge that the potential may exist for it to be found there [43]. CEPA suggested that the standard wall pipe used in Class 1 locations is more susceptible to SCC because it operates at higher stress levels than pipe in other class locations [44].

3.6.4 Stress level effects on crack initiation and growth

In this section we summarize the information collected on how the stress in the pipeline (the level of stress, fluctuations in the stress level and pressure fluctuation rate) affects the initiation and growth of SCC cracks.

Most research into near-neutral pH SCC has focused on how SCC grows than on how it initiates. However, field data are providing evidence of trends in both initiation and growth [45].

SCC crack initiation. One of the goals of conducting research on crack initiation is to find a threshold stress level below which cracks will not develop. However, the research community has not agreed to a single definition of threshold stress. Parkins [46] defines the threshold stress as being the stress above which cracks initiate and grow to failure. Other researchers have proposed that a given crack growth rate be used to define a threshold stress, while still others have proposed that the stress level that will grow a crack to a specific depth should define threshold stress.

At this time, Parkins' work provides the only laboratory data on threshold stress levels for near-neutral pH SCC initiation [47]. He found that on a sample of grade 448 MPa (65 ksi) steel taken from the TransCanada system, he could grow cracks at a stress level of 69 per cent SMYS with an R value of 0.5, but not at lower stress levels. Similarly, he could grow cracks at a stress level of 72 per cent SMYS with an R value of 0.85, but not below that level. He cautioned that these data are limited and need to be replicated to have validity. Parkins further cautioned that applying a single threshold stress value over the entire length of a pipeline may be unwise [48].

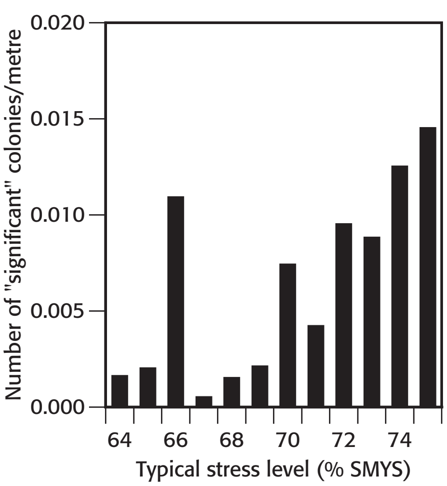
CEPA and several researchers also commented on the effect of stress on crack initiation:

- CEPA indicated that *"…at lower stress levels associated with heavy wall pipe locations, the probability of SCC initiation is reduced and those colonies that do initiate contain fewer cracks and are more widely spaced than those observed on standard wall pipe at higher stress levels."* [49]
- CEPA stated *"It is likely that such a value* [threshold stress] *exists, however, it is likely to* [be] *so low as not to be of practical engineering value."* [50]
- Leis indicated *"…lower stresses can be expected to reduce the nucleation of SCC."* [51]
- Beavers stated *"…I do not believe that there is a 'threshold stress' below which SCC cannot initiate. Stress corrosion cracks will initiate in the pipe if the environmental conditions are conducive to cracking because of the presence of residual stresses and pre-existing defects that act as stress raisers."* [52]

Field data also indicated that initiation is affected by stress caused by internal operating pressure:

- TransCanada has not detected "significant" SCC in Class 2 or 3 locations through investigative excavations, hydrostatic retesting or SCC in-line inspection [53]. Pipe in Class 2 and

Figure 3.17
Number of "significant" colonies detected per metre of pipe inspected for line 100-2 (TransCanada)

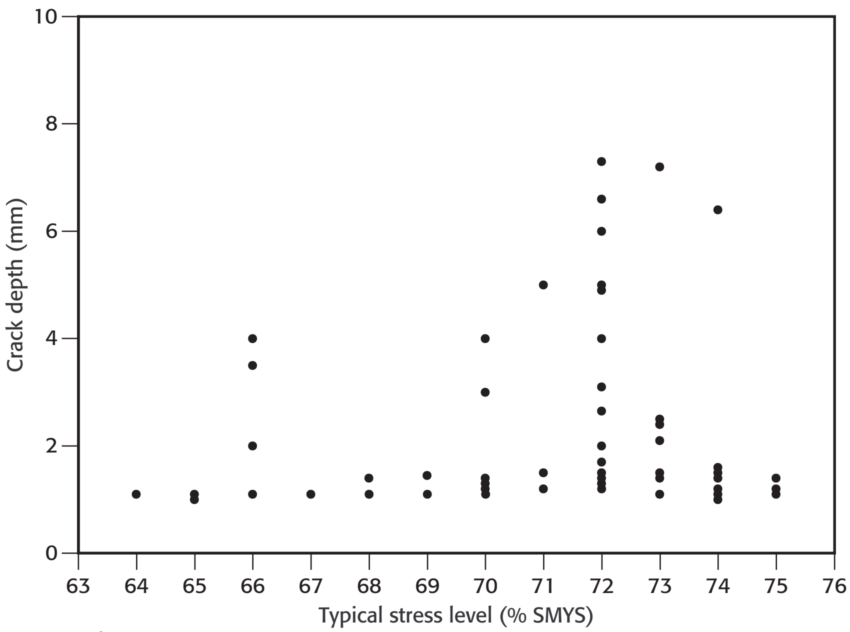


Source: Adapted from endnote [55]

3 locations in the gas transmission industry is typically designed to operate below 60 per cent SMYS [54].

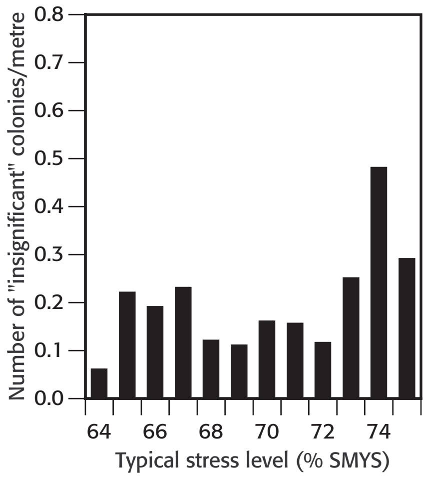
- Evidence presented by TransCanada suggests that the extent and severity of SCC increases where stress levels due to the internal operating pressures are higher. Figure 3.17 shows the relationship between the number of "significant" SCC colonies found per metre of pipe inspected and the stress level in per cent SMYS for TransCanada line 100-2 (914 x 9.1 mm, grade 448 MPa pipe). The figure shows a drop in the number of colonies from 0.014 to 0.0005 per metre inspected as the stress drops from 75 to 67 per cent SMYS. However, there is a second peak at 66 per cent SMYS that is not understood. TransCanada notes, on the basis of Figure 3.17, that the incidence of SCC drops significantly at stress levels below 70 per cent SMYS [56]. This same trend appears in Figure 3.18, which shows the relationship between crack depth and stress level for the same data presented in Figure 3.17. Figure 3.19 shows the relationship between the number of "insignificant" colonies found by TransCanada and stress level. It should be noted that the numbers are significantly higher – approximately 40 times higher – than in Figure 3.17, as indicated by the vertical scale. Also, the number of "insignificant" colonies does not appear to be related to the hoop stress level.
- The seven in-service ruptures that TransCanada has experienced have all occurred where normal operating

Figure 3.18
Maximum crack depths of "significant" SCC detected on line 100-2 (TransCanada)



Source: Endnote [57]

Figure 3.19
Number of "insignificant" SCC colonies detected per metre of pipe inspected for line 100-2 (TransCanada)



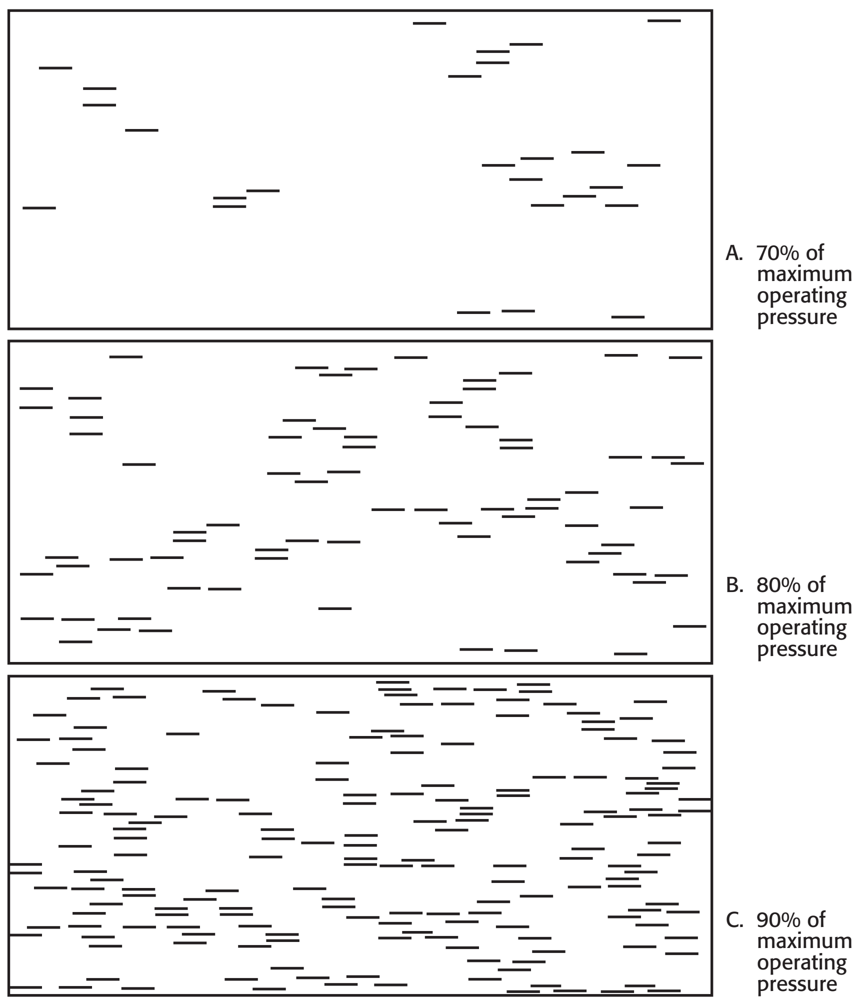
Source: Adapted from endnote [58]

hoop stress levels based on the internal operating pressure were more than 70 per cent SMYS [59].

SCC crack number. The maximum stress determines the number of cracks that initiate. The higher the stress level, the more cracks there will be and the closer they will be spaced. Leis presents data supporting the relationship between crack spacing and maximum operating pressure. His model predicts that at higher stress levels, more cracks will be present and they will be closer together (Figure 3.20).

SCC crack growth. The effect of stress on crack growth is important for three reasons. It determines whether there is a threshold stress level below which cracks will not grow, whether increasing the stress in a pipeline causes cracks to grow faster and how often hydrostatic retests should be scheduled.

Figure 3.20
Simulated cracking patterns versus maximum pressure



Source: Endnote [60]

Cracks grow in two ways. They increase in length and depth due to dissolution and hydrogen embrittlement. They also grow when several cracks join together and create a significantly longer crack.

The effect of stress level by itself has not been evaluated in the research conducted to date. The research conducted has involved stress level and stress fluctuations together.

Beavers indicated that [61]:

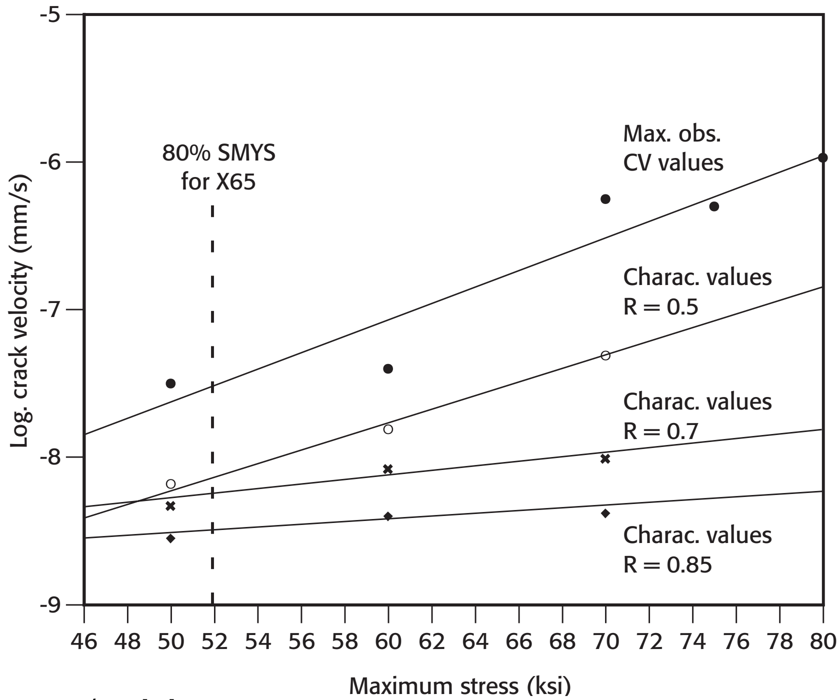
In constant displacement rate testing and ongoing cyclic load testing for TCPL, we have only observed cracking where dynamic loading conditions are present. No evidence of crack growth has been found under constant load or constant displacement conditions.

His comment points out the importance of the question of pressure fluctuations. While Parkins [62] agrees with this statement, Wilmott [63] suggests that further research is needed to define the role of pressure fluctuations on crack growth. For example, in laboratory bending tests, he was able to make existing field SCC cracks grow longer at stresses from 40 to 100 per cent SMYS where load was essentially constant, that is, where R-ratios (stress fluctuations) were 0.98. But preliminary research at CANMET and The University of Waterloo shows that pressure fluctuations are necessary for cracks to occur with near-neutral pH SCC. When CANMET carried out a full-scale test, no crack growth was found under static load conditions (when load was held constant), even at stress levels as high as 80 per cent of actual yield strength [64].

While looking at the effects of stress levels and stress fluctuations separately would be helpful, the available research data do not permit this. The most complete set of laboratory data is available from Parkins and is shown in Figure 3.21. Parkins conducted laboratory tests on smooth-sided specimens in an NS4 environment (a weak carbonic acid environment found in the field and used for a broad range of laboratory testing). Parkins tested X65 (grade 448 MPa) steel in a stress range from 52 ksi (80 per cent SMYS) to 70 ksi (108 per cent SMYS) with R-ratios of 0.5, 0.70 and 0.85. He found a direct relationship between maximum stress and an increased crack growth rate for the lower R-ratios, 0.5 and 0.7. At an R-value of 0.85, which is typical of gas pipeline operations, he found no effect of stress level on the measured crack growth rates. Conversely, at lower R-values such as 0.5, which is more typical of oil pipelines, there is a definite relationship between stress level and an increased growth rate.

Parkins commented that at each stress level and R-ratio (the highest curve in Figure 3.21), the highest crack velocity values for individual specimens are more representative of actual service failure times than those represented by the average data for R of 0.85 which should be typical of a gas transmission pipeline. One problem with this data set is that it starts at 80 per cent SMYS and examines higher stress

Figure 3.21
Near-neutral pH SCC growth rates as a function of stress amplitude and maximum stress for an X65 steel in TransCanada's 36 inch pipeline



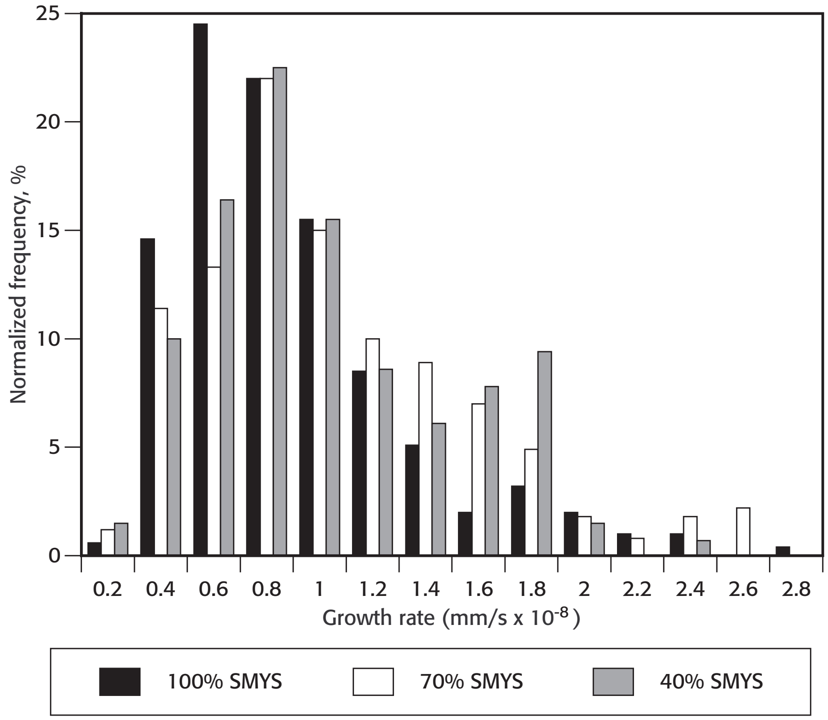
Source: Endnote [65]

levels but does not explore the trend at lower stress levels. Parkins was unable to initiate cracks which grow to failure at stresses below about 70 per cent SMYS.

Laboratory research conducted by Wilmott at NRTC shows that *"…for small shallow SCC cracks the rate of elongation is independent of the applied load from 40 per cent to 100 per cent SMYS."* Figure 3.22 presents the Wilmott data for 40, 70 and 100 per cent SMYS stress levels with a 0.98 R-ratio. This research measured crack growth rates based on increases in the surface length of a pre-existing SCC service crack (stress corrosion cracked pipe was used for the samples) in a bending test. The crack growth measurements are twice the increase in length for a single crack tip. The relationship between the changes in crack length reported by Wilmott and the changes in crack depth reported by Parkins is unknown. These results indicate that the crack growth rates appear to be similar at 40, 70 and 100 per cent SMYS. However, the results are widely scattered: the crack growth rates range from 0.2 to 2.8 x 10^{-9} mm/s at all three stress levels.

CEPA's position is that *"Crack growth can occur by a combination of continued initiation of new cracks, extension of existing ones, and coalescence with nearby cracks. At normal operating stress levels, growth rates appear to be essentially independent of maximum stress and R-value*

Figure 3.22
Crack growth rate distribution from crack growth studies at various load levels (NRTC)



Source: Endnote [66]

and is instead, controlled by environment." [67] However, several researchers indicated that they expect to find crack growth rates related to stress level, as indicated by the following comments:

- Parkins referred to his laboratory research work on the effects of stress fluctuations (R-value) and maximum stress on crack growth rates (Figure 3.21). He prefaced his work by stating [68]:

  It is to be expected that increase in the maximum stress and /or decrease in R value will be more likely to promote the formation of deeper cracks.

  It should be noted, however, that Parkins' work was carried out at stress levels significantly above those found in operating pipelines, so it is difficult to define a trend for typical operating stress levels.

- Parkins further indicated [69]:

  So far as attempting to control the incidence of SCC by control of the stressing conditions on pipelines is concerned, since I believe there are threshold conditions, at stresses that probably depend on the environmental conditions, the steel *involved and the stressing conditions, it follows that, in principle, SCC growth can be avoided by such approaches. The difficulty in applying that approach to control at present is that there are virtually no laboratory data upon which to base the choice of conditions to be applied in the field.*

- Leis notes that reducing pressure or pressure fluctuations in order to reduce stress in a pipeline with SCC will not stop cracking. However, it may marginally reduce the rate of crack growth. Leis states that [70]:

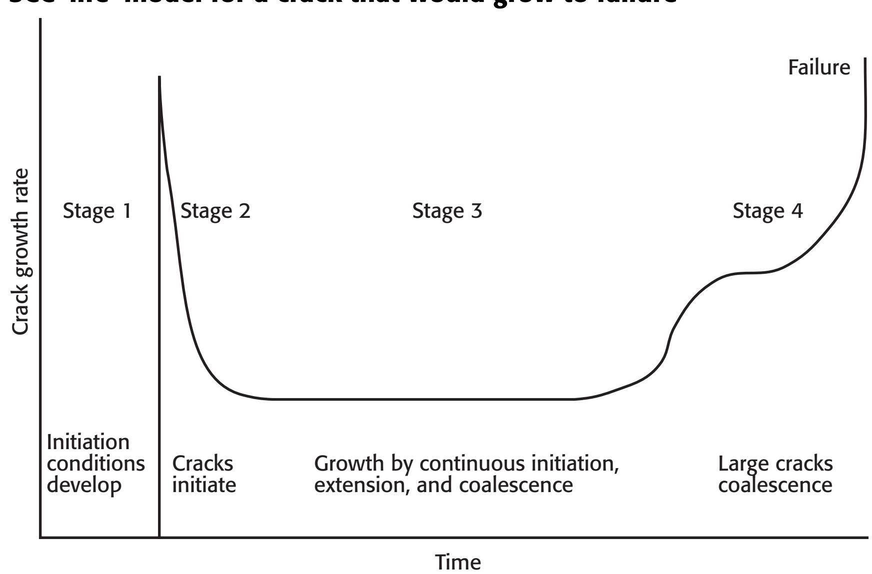
  Difficulties remain in assessing the extent of this rate reduction in that laboratory data do not reflect field conditions.

- The role of stress on crack growth is also discussed by Beavers [71]:

  I believe that it would be safe to assume that the probability of crack initiation and subsequent cracking velocity both would decrease with decreasing applied stress.

- Analysis of the data from TransCanada's investigative excavations indicates that crack depth increases at higher stress levels (Figure 3.18). TransCanada attributes this finding to higher loading rates at locations near compressor stations rather than higher stress levels [72].
- The analysis of the seven SCC ruptures on the TransCanada system indicates the maximum crack growth rate for gas

Figure 3.23
SCC 'life' model for a crack that would grow to failure



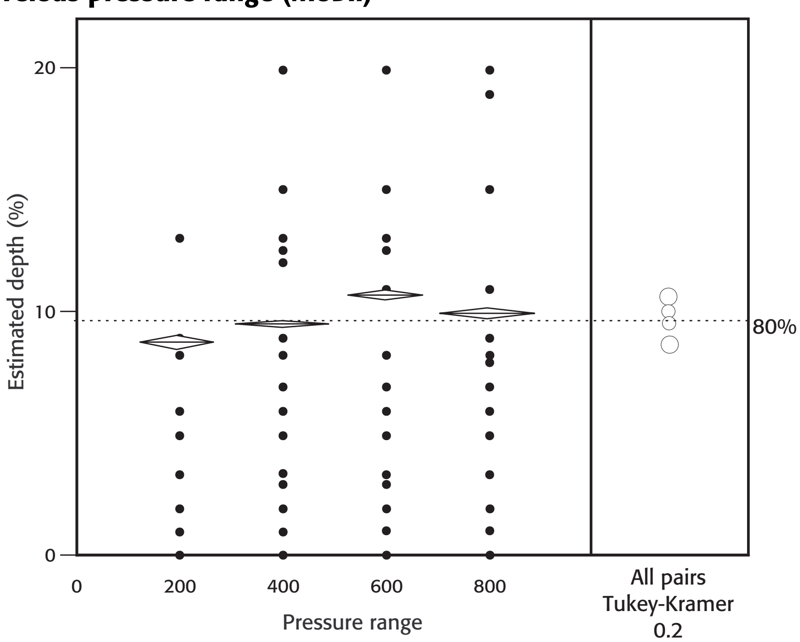
Source: Endnote [74]

pipelines is in the vicinity of 2 x 10^{-8} mm/s (0.63 mm/yr) [73]. This growth rate represents a time-averaged value, i.e., from Stage 1 to Stage 4 (Figure 3.23), not an absolute value, since crack growth is essentially governed by chance, where there are periods of rapid crack growth interspersed with periods of dormancy [75]. Growth rates vary with the steel microstructure: thus, growth rates are some 30 per cent higher in the heat affected zone (HAZ) next to pipe welds [76] and growth can stop when cracks encounter pearlitic bands in the steel microstructure [77].

- Krishnamurthy presented in Figure 3.24 the means comparison between crack depth and the ranges in the pipeline operating pressure. He noted that [79]:

  The pressure ranges 600 and 800 [psi] *exhibit significantly (80 per cent confidence) larger crack depths as compared to 200 and 400* [psi]*. This may imply an increased propensity for cracking at higher pressures. However, when pressure varies from 400 to 600* [psi]*, the crack depths are significantly (80 per cent confidence) larger than when the pressure is between 600 and 800* [psi]*. Additionally, parameters such as crack length, and colony size were also evaluated as a function of pressure, and no such trends were evident. The implication of such data, is that despite a limited relationship to operating pressure, there are perhaps other factors influencing the cracking.*

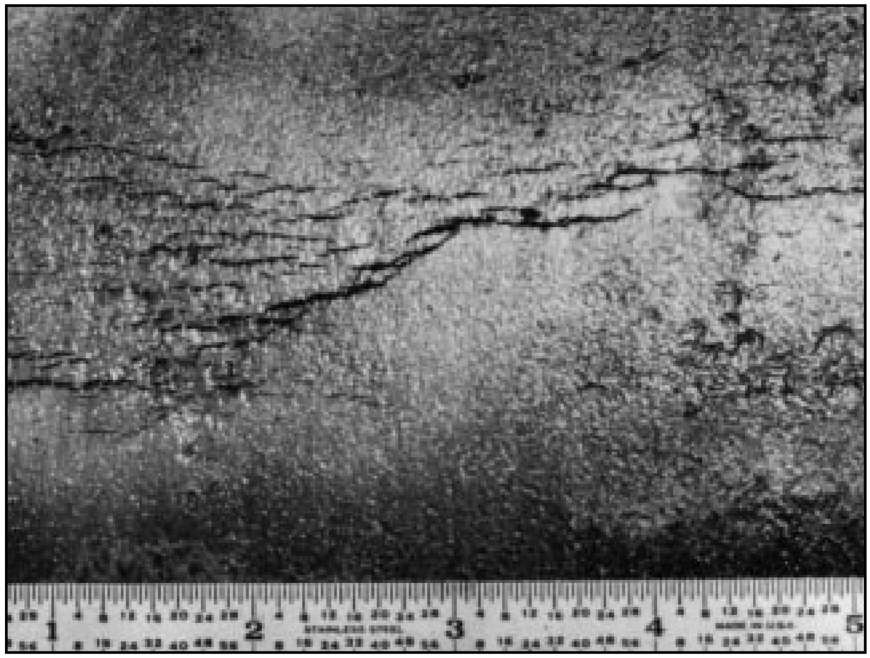
Figure 3.24
Means analysis of estimated depth (per cent wall) versus pressure range (Mobil)



Source: Endnote [78]

Effect of crack coalescence on crack growth. Crack coalescence is another factor affecting crack growth rates. Crack coalescence is the result of individual cracks joining together at the crack tips to form longer cracks (Figures 3.25, 3.26). CEPA states that [80]:

Figure 3.25
Coalescence of several cracks



Source: Endnote [1]

Figure 3.26
Cracks approaching coalescence

Source: Endnote [11]

If cracks nucleate in close proximity to one-another, as [is] *suggested could occur at higher operating stresses, then crack growth could be dominated by the coalescence of collinear cracks.*

Coalescence can occur throughout the SCC life cycle (Figure 3.23). Depending on the size of the crack, either environmental or mechanical forces will cause the cracks to grow during Stage 3. In Stage 4 of growth, coalescence occurs by tearing [81], where mechanical loading has a stronger effect in producing crack growth [82]. The presence of coalescence throughout the life cycle was disputed by Beavers in that he has found no evidence of coalescence late in the life of a pipeline, from the analysis of ruptured specimens [83].

Research at NRTC has shown that the geometry of the SCC colony is important in determining whether cracks will coalesce and grow to failure. Colonies of cracks which are long in the longitudinal direction but narrow in the circumferential direction present more of a threat to pipeline integrity than colonies of cracks that are about as long as they are wide. In long, narrow colonies, individual cracks that are aligned head to tail can link up and can lead to rupture. But in colonies of cracks which are equally long and wide, growth occurs primarily on the edge of the colony [84]. Cracks located deep within these colonies shield each other from stress and become dormant [85].

The cracks in colonies will be closer together or further apart and so the crack spacing may be described as being either “sparse” or “dense”. Leis uses a circumferential spacing equal to 20 per cent of the wall thickness between cracks as the distinguishing criterion between sparse and dense. Cracks circumferentially spaced closer than 20 per cent of the wall thickness tend to go dormant, whereas cracks spaced further apart (at distances greater than 20 per cent of the wall thickness) can continue to grow [86]. This information shows that crack coalescence is a possible influence on crack growth but, as the various researchers have stated, there is no predictive model which has been developed that allows us to define the influence of coalescence on crack growth. Here again, the research in this area is incomplete.

Effect of rate of pressure change rate on crack initiation and crack growth. Very little research has been conducted on the effect of the rate of pressure change or strain rate (which is how the pressure rate affects the pipe steel) on crack initiation and growth. In its work to develop a model of crack growth rate, the University of Waterloo conducted a series of experiments using a bending test fixture in which the loading rate was varied from 40 to 400 to 5 000 cycles per day with three R-ratios, 0.50, 0.82 and 0.90. In each set of data, the maximum stress intensity was held in the range of 34 to 38 MPa√m. This is analogous to keeping the crack driving force at the crack tip at the same level. The results indicate that the slower frequencies gave faster per-cycle growth rates. This was because, at low frequencies, crack growth per cycle was higher since there was more time for the environment to interact with the crack, increasing the growth rate [87].

A further indication of the significance of the rate of loading was provided by Beavers [88]. He indicated that he thought the appropriate crack driving force parameter was the J integral since this factor considers crack tip plasticity and plasticity appears to be related to the cracking process. (The J integral or stress intensity factor K, as defined in fracture mechanics, is a function of crack size, the stress acting on the crack and the structural geometry of the crack.) Recent results have modified Beavers' thinking because the constant displacement rate testing has shown that the rate of change of J with time must also be incorporated in a crack driving force parameter. This is an area where the research is incomplete.

3.7 Conclusions

Although there is much research to be done to better understand near-neutral pH SCC, we know that three conditions are required to act together for SCC to form:

- a potent environment at the pipe surface,
- a susceptible pipe material, and
- a tensile stress.

The findings with regard to these three factors are discussed below.

3.7.1 Environment

The environment at the pipe surface is affected by four factors: the type and condition of coating, soil, temperature and cathodic current level. All occurrences of SCC involve both failure of the coating (disbondment or holiday formation) and the lack of cathodic protection of the pipe surface. Without cathodic protection, the environment at the pipe surface, which is influenced by soil conditions and chemistry as well as temperature, can cause the initiation of near-neutral pH SCC.

We found that research into the environment conducive to SCC is incomplete in the following areas:

- the relationship between anaerobic soil conditions and the occurrence of near-neutral pH SCC;
- a means to drive cathodic current under disbonded tape coating to prevent formation of the near-neutral pH environment;
- alternative ways to drive the cathodic current through high resistivity soil to the pipe surface; and
- the role of sulfides produced from sulfate-reducing bacteria, which act as a poison for the atomic hydrogen created by the environment.

3.7.2 Material

There does not appear to be a correlation between near-neutral pH SCC and pipe composition, grade, manufacturer or manufacturing process. With one exception, all of the steels examined have indicated a comparable susceptibility to near-neutral pH SCC. The exception was the ERW pipe manufactured by Youngstown. The ERW seam area of Youngstown pipe has been found to exhibit a lower resistance to near-neutral pH SCC formation than the base metal.

We found that research into pipe materials is incomplete in the following areas:

- the susceptibility of high strength steels to SCC and/or hydrogen embrittlement and the tolerance of high strength steels to SCC and other defects;
- the susceptibility of the coarse-grained heat-affected zone to cracking, relative to the base material in the near-neutral pH environment;
- the role of cyclic-softening in controlling the formation of plasticity on the surface of a pipe and the feasibility of altering the cyclic-softening characteristics of steel through hydrostatic retesting procedures;
- the relationship between the incidence of SCC and the number and size of non-metallic inclusions; and
- the relationship between the condition of the pipe surface and the threshold stress level for the initiation of SCC.

3.7.3 Stress

Field data and laboratory data indicate that stress has an effect on initiation and possibly on the growth rate of near-neutral pH SCC. We also found that pressure fluctuations and strain-rates have an effect on crack growth as identified by laboratory data. However, we found that the available information is limited and conflicting.

While field data show a significant reduction in the incidence of SCC below a hoop stress caused by pressure of 70 per cent SMYS, research has not found a threshold stress below which cracks will not grow to failure. Some evidence suggests that the threshold stress level and the level of pressure fluctuations are interrelated and that the threshold may vary along the length of the pipeline. The evidence indicates that the total stress on a pipeline should be considered. The hoop stress caused by the internal pressure is only one component of total stress. In almost all pipeline failures associated with SCC, local stress intensifiers such as corrosion, gouges or stress concentrations at the toe of the weld seam have been present.

We found that research into stress is incomplete in the following areas:

- the role of stress level, stress fluctuations and strain rate, individually and in combination, at realistic operating stress levels, on the initiation and growth of SCC;
- the R-ratio (daily, weekly, monthly or yearly) which controls the SCC behaviour of gas and liquid pipelines;.
- the role of crack coalescence in crack growth; and
- understanding of residual stress in the initiation and growth of SCC and possible ways of reducing or minimizing the level of residual stress in pipelines.

Recommendation

3-1 We **recommend** that the Board require pipeline companies to examine ERW pipe manufactured by Youngstown Sheet and Tube located in SCC susceptible soils for evidence of SCC.

3-2 We **recommend** that the Board request that CEPA provide, by 30 June 1997, an analysis of the extent to which the areas of incomplete research identified in this report are addressed in the current SCC research program and the merits and implications of expanding this program to cover these areas.

Chapter Four

Prevention, Detection and Mitigation

4.0 Introduction

Our understanding of how near-neutral pH SCC initiates and grows was set out in Chapter 3. Pipeline companies, industry groups and researchers have looked for ways to prevent, detect or remove SCC before it grows to the point where an in-service pipeline failure results. In the previous Inquiry, the Board evaluated the effectiveness of different ways to prevent service failures caused by near-neutral pH SCC. The mitigative measures evaluated included hydrostatic retesting, reduction of operating pressure, selective pipe replacement and investigative excavations and repairs.

Since that Inquiry, these and other techniques have been used and there is now more experience with them and more information about their effectiveness. In addition, research has improved the understanding of the principles underlying these techniques. Taking into account this experience and improved understanding, we evaluated these and other measures for the prevention, detection and mitigation of the effects of near-neutral pH SCC.

The measures discussed in this chapter are:

- coatings,
- predictive models,
- investigative excavations and repairs,
- in-line inspection,
- pressure reduction,
- hydrostatic retesting, and
- selective pipe replacement.

Each was evaluated on the basis of its effectiveness in preventing service failures or in minimizing the consequences of service failures.

4.1 Coatings

The corrosion control system for a buried pipeline consists of two parts: the external coating on the pipeline and the cathodic protection system. The primary purpose of the coating is to protect the pipe surface from its external environment. In the event that the coating disbonds from the pipe, the cathodic protection system is designed to protect the pipe from corrosion.

As discussed in Chapter 3, the occurrence of near-neutral pH SCC on Canadian pipelines has been largely due to the failure of polyethylene tape coatings which were applied to pipelines installed between 1968 and 1973. Clearly, these coatings did not have the properties needed to provide long-term protection against SCC.

In the Inquiry, different types of coating systems were evaluated in terms of their ability to protect the pipe surface over the life of the pipeline. The use of coating systems for new pipelines and the recoating of existing pipelines are discussed in this section.

4.1.1 Coatings for new pipelines

CEPA stated that *"…*[the] *most viable way of reducing SCC initiation on new pipelines is through the use of high-performance coatings in conjunction with effective cathodic protection."* [1] CEPA considers that fusion bonded epoxy, urethanes, liquid epoxies, extruded polyethylene and multi-layer coatings are high-performance coatings.

CEPA identified three criteria for assessing the effectiveness of a coating in preventing SCC [2]. They relate to the ability of the coating to:

- prevent the environment/electrolyte which causes SCC from contacting the pipeline steel surface (i.e., remain bonded to the pipe);
- allow the passage of CP current which prevents the initiation of SCC should the coating fail; and
- alter the pipe surface during the coating application so that it is less susceptible to SCC initiation.

In respect of the first criterion, if the coating does not disbond from the pipe, the environment necessary for SCC initiation or growth cannot develop at the pipe surface and SCC is effectively prevented. Good, long-term bonding strength in a coating is therefore important for SCC-susceptible pipe.

However, over the service life of most coatings, some disbondment will likely occur. When it does, the pipeline's cathodic protection system acts as a back-up against near-neutral pH SCC. As noted by Beavers and Thompson [3], in order for the CP system to be able to protect the pipeline, the coating material must conduct CP current when disbondment occurs.

The first two criteria are recognized in CSA Z662, which requires that coatings have the following properties [4]:

> *9.2.8.1 Properties*
>
> *Coatings shall*
>
> *a) electrically isolate the external surfaces of the piping from the environment;*

b) *have sufficient adhesion to effectively resist underfilm migration of moisture;*

c) *be sufficiently ductile to resist cracking;*

d) *have sufficient strength or otherwise be protected to resist damage due to soil stress and normal handling;*

e) *be compatible with cathodic protection;*

f) *resist deterioration due to the environment and service temperature; and*

g) *where plant applied, comply with the requirements of the appropriate CSA Z245 standard, where one exists.*

Coatings that meet the performance criteria set out in the CSA standard would therefore meet the first two criteria identified by CEPA for preventing SCC. However, although Clause 9.2.8.1(f) of the standard suggests that these properties should be maintained over the service life of the pipeline, there is no specific requirement to demonstrate the long-term performance of the coating.

With respect to the third criterion, laboratory and field tests conducted by the PRC*I* indicate that grit blasting a pipe surface renders it more resistant to SCC initiation [5]. When grit blasting is used to clean the pipe surface prior to coating application, it removes the majority of the mill scale and changes the residual stress condition of the steel surface, thereby minimizing initiation sites for SCC.

Coating systems that meet all three criteria are effective in preventing SCC. Fusion bonded epoxy, urethanes and liquid epoxy coatings meet all three criteria. The long-term performance of these coatings attests to this effectiveness. CEPA states that FBE coatings have been in use for over 25 years and there have been no reported incidents of SCC, even on pipelines in locations known to cause SCC; and liquid epoxies and urethanes have been in use for over 13 years, with similar success [6].

However, a coating system does not have to meet all three criteria to be effective in preventing SCC. Extruded polyethylene coatings applied according to CSA Z245.21-M92 meet only the first and third criteria. CEPA notes, however, that in over 20 years of experience with this type of coating, there have been no reported cases of SCC [7]. Thus, there is evidence of proven long-term performance in preventing SCC.

Multi-layer and composite coatings are relatively new types of coatings. Multi-layer coatings consist of an inner layer of FBE and an adhesive layer followed by an outer polyolefin layer. Composite coatings are a version of a multi-layer coating with inner FBE and outer polyethylene layers but the adhesive is replaced with a graded layer of FBE and modified polyethylene. CEPA notes that the potential for tenting across a raised weld remains a concern for multi-layer coatings that are extruded [8]. Since these coatings are relatively new, their long-term effectiveness in preventing SCC is unknown. Until that effectiveness has been demonstrated (e.g., through experience or accelerated laboratory tests), careful consideration is needed before using these coatings for SCC-susceptible pipelines. If SCC does occur over the life of the pipeline, costly mitigative measures may become necessary.

According to CEPA, bituminous enamel coatings (asphalt and coal tar) meet the first criterion, but may not meet the other two [9]. However, as discussed in Chapter 3, unless the pipe surface is adequately prepared, these coatings may be prone to disbondment due to soil stresses. Near-neutral pH SCC has occurred on pipelines with these coatings in high resistivity soils, where the CP current was unable to reach the pipe surface.

Modern polyethylene tape coatings have improved bonding strength and damage-resistance compared to the earlier versions associated with most of the SCC on Canadian pipelines. However, they still shield the pipe from CP current when they disbond and the pipe surface preparation process does not result in added resistance to SCC initiation. The long-term effectiveness of modern tape coatings in preventing SCC is unknown. Therefore, careful consideration is needed before using them for SCC-susceptible pipelines.

It should be noted that girth weld coatings are applied in the field after the pipe joints have been welded together. The effectiveness of girth weld coatings is as important as the coating on the main body of the pipe in terms of preventing SCC initiation and growth and should meet the same three criteria.

4.1.2 Recoating existing pipelines

The principal reason for considering the recoating of long sections of a pipeline is the failure of its existing coating system. Pipelines that may require recoating are those with coating types that have historically contributed to the development of SCC by disbonding from the pipe and shielding the exposed steel surface from cathodic protection current.

Recoating long sections of a pipeline involves excavation of the pipeline, removal of the old coating, preparation of the pipe surface and application of the new coating. These operations depend on the type of the replacement coating that is to be used.

Not all coatings that are available for new lines can be used to recoat an existing pipeline. CEPA stated that, currently, pipeline recoating can be done using either conventional single or double-wrap tape systems, or liquid epoxy and urethane coatings [10].

TransCanada indicated that, before recoating long sections of a pipeline, the integrity of the pipeline must be demonstrated to ensure that there are no near-critical flaws on the pipeline [11]. This would normally be done with a hydrostatic retest.

CEPA indicated that, in most cases, projects involving the recoating of long sections of pipeline have not been economical [12]. Recoating costs can vary from 50 per cent of the cost of a new line to more than the total cost of a new line [13]. The costs vary considerably because there are numerous variables inherent in a recoating operation including specific terrain conditions, soil types, type of coating to be removed and the type of rehabilitation coating. There are also the costs to assess pipe integrity and possibly perform pipe repairs, as well as the costs associated with service interruptions.

TransCanada indicated that recoating costs are currently under study [14]. The company indicated that it plans to conduct a coating rehabilitation project to assess the feasibility of recoating long distances of pipeline using the latest technology [15].

4.1.3 Conclusions

The use of effective pipe coatings is the most practical way of preventing SCC on new pipelines or when recoating existing pipelines. We believe that the three criteria identified by CEPA provide a sound basis for choosing an effective coating.

Our concerns relate to the absence of standard tests to determine whether a coating will meet these criteria over the expected service life of the pipeline.

We consider that effective coatings are those that meet all three criteria or have proven long-term performance in preventing SCC. We believe that the use of effective coatings, combined with adequate levels of cathodic protection, has already gone a long way to preventing the initiation of SCC on pipelines brought into service in the last two decades, and will continue to do so in the future. Whenever possible, coatings with demonstrated effectiveness should be used for coating new lines, including girth welds, and for recoating existing lines.

We consider that fusion bonded epoxy, urethanes, liquid epoxy and extruded polyethylene coatings have established their effectiveness in protecting pipelines from SCC.

Careful consideration is required before deciding to use any other type of coating on SCC-susceptible pipelines, if they do not meet the criteria discussed above and their long-term performance has not been demonstrated. If other coatings are used and SCC occurs over the life of the pipeline, costly mitigative measures may become necessary.

Finally, we consider it mandatory that, before a section of pipeline is recoated, its integrity must be demonstrated.

Recommendation

4-1 We **recommend** that the Board request that the CSA Technical Committee on Oil and Gas Industry Pipeline Systems, the pipeline industry and coating manufacturers coordinate efforts to:

a) develop standard tests, where none currently exist, that determine whether a coating will meet the performance criteria set out in the CSA Z662-94 standard over the anticipated service life of a pipeline;

b) incorporate those tests in the appropriate CSA standards; and

c) conduct objective studies based on those tests to demonstrate the long-term performance of the different types of coatings currently available for pipelines.

4.2 Predictive models

Predictive models are intended to identify and rank those areas along a pipeline system that are the most likely to have "significant" SCC based on the various factors which are known to contribute to susceptibility to SCC. (The definition of "significant" SCC is discussed in section 4.3.1.) These factors include:

- the type of coating,
- the year of pipeline installation,
- the operating history of the pipeline, and
- the terrain conditions (soil type, drainage and topography).

By themselves, predictive models neither directly prevent service failures due to SCC nor do they reduce the consequences of such failures. However, by identifying those locations where SCC is most likely to occur, a predictive model allows a company to direct its investigative excavations and other mitigative activities to where they will have the most effect.

This section discusses the development of a predictive model, the effectiveness of such models and how they can be used to manage an SCC-susceptible pipeline.

4.2.1 Development of a predictive model

The information collected by TransCanada during its investigative excavations in the late 1980s suggested that the occurrence of "significant" SCC on a pipeline was strongly related to the terrain conditions surrounding the pipe where there was the potential for pipe coatings to have disbonded. Based on this observation, TransCanada employed J.E. Marr Associates (Canada) Ltd. in 1992 to develop a predictive model for SCC susceptibility.

Several other pipeline companies have since developed predictive models for SCC susceptibility. In most cases, these models have been based on the methodology developed by TransCanada and J.E. Marr Associates (Canada) Ltd. [16]. At the time of the Inquiry, six CEPA member companies were using predictive models to assess the SCC-susceptibility of their systems, or portions thereof, and five other member companies were developing predictive models [17]. As well, one CAPP member has used a predictive model [18].

The data collected by various CEPA members have identified seven specific sets of terrain conditions associated with "significant" SCC on polyethylene tape coated pipelines. Another four specific sets of terrain conditions have been identified with "significant" SCC on asphalt coated pipelines. These 11 sets of terrain conditions are referred to as "significant terrain conditions" [19] and are outlined in Tables 4.1 and 4.2. It is important to note that the presence of these terrain conditions along a pipeline system means only that the environmental conditions may exist for "significant" SCC to develop. If any of the other conditions necessary for SCC initiation and growth (e.g., coating disbondment, susceptible pipe material and stress) are not present, SCC will not develop at that location.

In general, the first step in the development of a predictive model is to review the background information for a specific pipeline. The data will include, among other things, the pipeline's operating history, its coating type and its year of construction. The more current and complete the available pipeline data, the better the initial model.

The second step is to get information about the existing terrain conditions along the system. Aerial photos and soil surveys are used here. The pipeline data are then correlated with the actual terrain conditions to form a database. Finally, the gathered information is cross-referenced with the "significant terrain conditions" known to promote SCC [20].

Areas along the pipeline system are then identified as being susceptible or non-susceptible to SCC. Areas identified as susceptible to SCC can also be ranked as to their relative susceptibility.

As investigative excavations are carried out in these areas, the presence or absence of SCC and specific details on the terrain conditions are recorded. The information collected is then used to verify and enhance the predictive model. As more excavations are performed, the model is further refined and its accuracy improves.

While the information on terrain conditions known to promote SCC susceptibility may be applied to all pipelines in the same area, a predictive model can be used only for the pipeline for which it was developed. That is because the data about each pipeline – its coating, its year of construction, its operating history – may be quite unique and

Table 4.1
Description of significant terrain conditions for polyethylene tape coated pipelines

Soil environment description	Topography	Drainage
Clay bottom creeks and streams (generally <5 m in width)		
Lacustrine (clayey to silty, fine textured soils)	inclined level undulating	very poor
Lacustrine (clayey to silty, fine textured soils)	inclined level undulating depressional	poor
Organic soils (>1 m in depth) overlaying glaciofluvial (sandy and/or gravel textured soils)	level depressional	very poor
Organic soils (>1 m in depth) overlaying lacustrine (clayey to silty, fine textured soils)	level depressional	very poor
Moraine tills (variable soil texture - sand, gravel, silt and clay with a stone content >1%)	inclined to level level undulating ridged depressional	very poor poor imperfect to poor
Moraine tills (variable soil texture - sand, gravel, silt and clay with a stone content >1%)	inclined	poor imperfect to poor

Source: Endnote [19]

Table 4.2
Description of significant terrain conditions for asphalt coated pipelines

Soil environment description	Topography	Drainage
Bedrock and shale limestone (<1 m of soil cover over bedrock or shale limestone)	inclined level undulating ridged	well drained
Glaciofluvial (sandy and/or gravel textured soils)	inclined level undulating ridged	well drained
Moraine tills (sandy soil texture with a stone content > 1%)	inclined level undulating ridged	well drained
Sites which do not meet the <850 mV "off" criteria used in the Close Pipe to Soil Corrosion Survey (exclusive of the three sets of terrain conditions discussed above)		

Source: Endnote [19]

this data is an important part of the predictive model. Consequently, assumptions should not be made about SCC susceptibility on one pipeline system on the basis of a predictive model developed for another system.

Cost. The cost of developing a predictive model will differ for every pipeline company, depending on the availability of the information required for the database. For example, the cost will be higher if the original pipeline construction documentation is not available. CEPA provided the following estimated costs for developing a predictive model [21]:

Pipeline database development	$80/kilometre
Investigative excavations	$1000/metre
Model verification	$120/kilometre
Model refinement	$25/kilometre

As the estimates show, the long-term costs of maintaining a predictive model will depend primarily on the number of excavations performed.

4.2.2 Effectiveness of predictive models

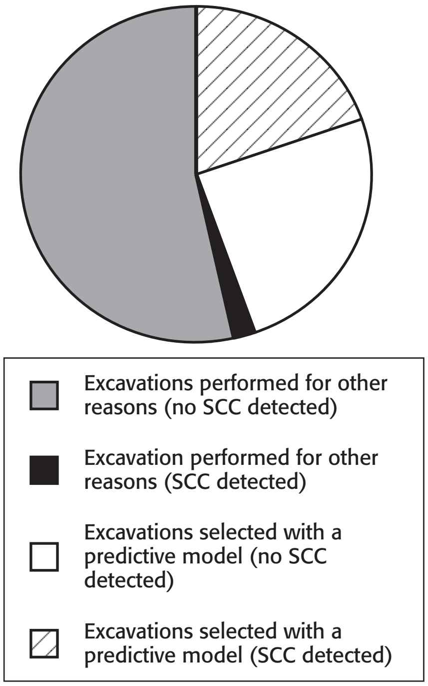
At the time of the Inquiry, CEPA member companies, primarily TransCanada, had completed 1,920 investigative excavations that included inspection for SCC. As shown in Figure 4.1, about 45 per cent of these excavations were selected using a predictive model and SCC was found at 44 per cent of those sites. When the inspections were carried out during routine maintenance activities, SCC was found at only four per cent of the sites.

This substantial increase in the amount of SCC found using predictive models demonstrates the effectiveness of predictive models in finding SCC. The data also demonstrate that relying on SCC investigations during routine maintenance activities may give misleading results in respect of a pipeline system's susceptibility to SCC.

Figure 4.2 provides a graphical representation of the effectiveness of predictive models developed by five CEPA member companies. Excavations were conducted at sites associated with "significant terrain conditions" and "non-significant terrain conditions". As the data show, SCC was detected two times more frequently at sites with "significant terrain conditions" than those with "non-significant terrain conditions". Also, while some "insignificant" SCC was detected at sites with "non-significant terrain conditions", no "significant" SCC was detected at those sites. These results indicate that the SCC predictive models developed by five CEPA member companies have been effective in identifying sites where SCC may be present.

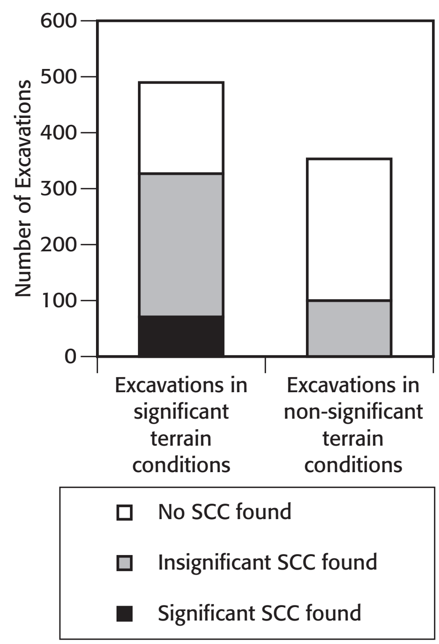
The models' effectiveness will depend on their accuracy for predicting sites susceptible to "significant" SCC. That accuracy will depend in large measure on the quality and reliability of the data used to develop the model. In this connection there are currently no developed

Figure 4.1
Effectiveness of predictive models



Source: Based on data from endnote [22]

Figure 4.2
Effectiveness of predictive models developed by 5 CEPA member companies



Source: Based on data from endnote [23]

Figure 4.3
Soil probe

Courtesy of NOVA

sampling criteria for companies to assist them in determining the appropriate number of excavations to verify a model's accuracy.

Soil probe. To increase the effectiveness of detecting SCC, several companies have been using a soil probe during their investigative excavations. The NOVAProbe®, developed by NGTL and NRTC, measures a number of soil characteristics active in the development of pipeline corrosion without requiring excavation. As the probe does not disturb the soil around the pipeline, the accuracy of selecting sites for SCC inspection improves, since additional information about the soil characteristics at pipe depth can be used along with information on site topography, soil type and drainage.

As shown in Figure 4.3, the NOVAProbe® incorporates several sensors in a single probe tip. In the field, the probe is pushed to the desired depth to measure the soil resistivity, redox potential, temperature and pipe-to-soil potential [24]. Because of heavy demand for the NOVAProbe®, NRTC has organized an industry consortium to make it more readily available to pipeline companies.

The information collected by the NOVAProbe® is also being incorporated into the CEPA SCC database (discussed in Chapter 6) to further determine if there are any correlations between the soil characteristics measured and the presence or absence of SCC.

4.2.3 Conclusions

We consider that predictive models can be effective in identifying and ranking areas along a pipeline that are susceptible to SCC, provided that:

- reliable pipe data and terrain information are used; and
- the predictive model is verified and continually enhanced as data from excavations become available.

By identifying those locations along a pipeline where SCC is most likely to occur, a predictive model enhances the effectiveness of other mitigative measures in preventing service failures or reducing the consequences of such failures.

When prioritizing susceptible areas for mitigation, it is important that the consequences of potential service failures be considered so that the risk due to SCC failures may be minimized.

Recommendations

4-2 We **recommend** that, if there is reason to believe that sections of a pipeline may be susceptible to SCC, the Board require the pipeline company to develop a predictive model to identify and prioritize sites for an investigative excavation program.

4-3 We **recommend** that the Board request that CEPA develop sampling criteria for verifying the accuracy of predictive models.

4.3 Investigative excavations and repairs

If SCC is detected before it grows to a critical size, repairs can be made and the risk of a service failure can be eliminated. One way of detecting SCC is by excavating around the pipe and inspecting it section by section. To be effective at preventing service failures due to SCC, however, the repair method must restore the integrity of the pipeline and eliminate the conditions necessary for further SCC growth.

4.3.1 Investigative excavations

Pipeline companies excavate around portions of their pipelines (Figure 4.4) as part of routine maintenance and these excavations create an opportunity to investigate for SCC. Companies can also conduct excavations specifically to look for SCC at locations selected on the basis of information from predictive models or in-line inspection. However, while predictive models are designed to identify locations that are most likely to have "significant" SCC, they are not able to distinguish those locations with near-critical cracks.

With respect to SCC-specific investigative excavations, CEPA stated that it is *"... not technically possible, at this time, to eliminate all potential for SCC failures on a pipeline on the basis of investigative excavations alone unless discretely susceptible locations are known to exist in isolated sections along the pipeline."* [25]

CEPA Recommended Guidelines. To assist its members in developing and implementing SCC investigative programs, CEPA has produced a manual of Recommended Guidelines which provides information on site selection, excavation procedures and inspection techniques [26]. These guidelines are specific to longitudinal near-neutral pH SCC and were written as a working document based on industry experience. An overview of the investigative excavation process, as detailed in CEPA's Recommended Guidelines, is outlined in the following paragraphs.

Before and during excavation, information about the terrain conditions at the site is documented. Terrain conditions include soil type, drainage and topography. Samples of soil and groundwater should be collected, as well, to further develop an understanding of the environmental parameters associated with SCC.

Following excavation, the pipe coating is examined for any disbondment or other damage. Normally, all areas of coating disbondment should be inspected for SCC. If liquid (electrolyte) is found beneath the pipe coating as it is being removed, a litmus paper pH reading is taken. Measurement of the pH in the field is very important

Figure 4.4
Investigative excavation

since ongoing chemical reactions within the sample can alter the pH prior to laboratory analysis. Nevertheless, subsequent laboratory measurements of pH for the same electrolyte can provide useful information about the processes associated with SCC.

As the pipe coating is removed, the presence of any corrosion deposits should be noted. It is important that a corrosion deposit be accurately identified. Combined with other specific environmental conditions, certain corrosion deposits are strongly related to either the presence or absence of SCC and provide information about the environment beneath the disbonded coatings.

To prepare the pipe for SCC inspection, the pipe surface must be cleaned and dried so that any SCC present can be reliably detected. Currently, high-pressure water blasting and walnut shell blasting are the only field-proven ways to clean the pipe surface for SCC inspection. Both methods remove the pipe's coating and primer, as well as any corrosion deposits or mill scale found on the pipe surface. However, the pipe cleaning process must be done carefully since mechanical damage to the pipe surface could result in SCC colonies being masked or misinterpreted.

After the surface has been prepared, the pipe is inspected for SCC using magnetic particle inspection (MPI) techniques (see Figure 4.5). The skill of the technician in recognizing SCC is a critical factor during this inspection process. It is essential that all SCC colonies present be identified correctly and then documented. The documentation should include, among other things, an assessment of the severity of the SCC detected.

Criteria for assessing the severity of SCC. SCC will be more advanced in some cases than in others. In order to be able to provide a consistent measure of the severity of SCC when it is found, TransCanada developed a set of definitions, or criteria, which classify the severity of

Figure 4.5
Magnetic particle inspection

Courtesy of TCPL

SCC colonies as either "significant" or "insignificant". These definitions take into account the colony's length and depth and the pipe's geometric and mechanical properties. A colony is "significant" if the deepest crack is greater than 10 per cent of the pipe wall thickness and the total length of the colony exceeds a crack length that would likely fail under a pressure test at 110 per cent of the pipe's SMYS [27]. SCC colonies that do not meet the "significant" criterion are classified as structurally "insignificant" [28].

It should be noted that SCC colonies that are classified as "significant" are not necessarily an immediate threat to the integrity of the pipeline. The criterion is deliberately conservative so that the pipeline company has adequate time to plan and implement remedial action before a crack grows to a critical size.

To properly evaluate the severity of an SCC colony, its depth and length must be accurately determined. These dimensions are then compared to a critical crack size calculated for that segment of pipe to assess if the pipe's integrity is threatened.

From the experience gained after grinding several hundred colonies, some CEPA member companies have developed a correlation between the length and depth of "insignificant" cracks. In this way, the depth of an "insignificant" crack can be estimated from its length [29]. However, the only way of accurately measuring the depth of SCC is through successive grindings with repeated wall thickness readings, combined with MPI, to confirm the continuing presence or removal of the colony [30].

4.3.2 Repair of SCC-affected pipe

The primary objective of any pipeline repair is to restore the integrity of the pipeline. This is generally achieved by removing any defects of a size that may fail in service. In the case of SCC-susceptible pipelines, another equally important objective is to eliminate the possibility of future SCC growth. This second objective is achieved through the application of a coating that will effectively eliminate the conditions necessary for SCC growth.

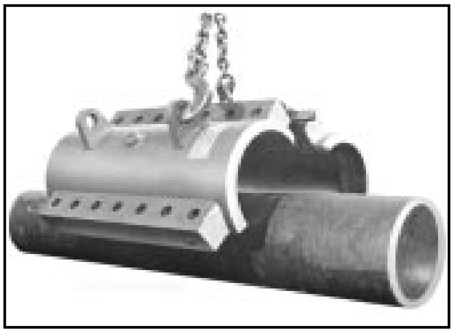
Once SCC has been detected and classified, a decision must be made as to which colonies can be left in the pipeline and which ones need to be removed. In making this decision, the company must review each SCC colony and take into account the pipe material, the pipeline configuration and location, the pipeline's operating characteristics and the extent of the cracking [31].

As a minimum, companies must meet the requirements of CSA Z662. That standard considers pipe body cracks to be unacceptable defects that must be removed, unless an engineering assessment determines that they are no threat to the pipe's integrity. Thus, if the nature and extent of stress corrosion cracks do not threaten pipeline

Figure 4.6
Grinding out SCC

Courtesy of TCPL

Figure 4.7
Full-encirclement reinforcing sleeve



Courtesy of PLIDCO

integrity, it is usually acceptable to make no repair, other than to replace the coating with a type of coating which will prevent further growth.

If the SCC must be removed from the pipe, the company has a number of choices. Currently, the repair methods allowed by CSA Z662 for cracks include cut-outs, grinding and grinding combined with the use of a full-encirclement reinforcing sleeve. Several additional repair methods may be included in the next edition of CSA Z662. Additional repair methods proposed by CEPA include pressure containment sleeves for cracks in the pipe body or mill seam welds and fibreglass reinforcement and steel reinforcement repair sleeves for metal loss in the pipe body [32].

The currently allowable repair methods have different advantages and disadvantages. When a cut-out is done, the pipe is cut all the way through on both sides of the damage and the cylindrical section of pipe containing the damage is taken out. A new segment of pipe is welded in its place. The advantage of a cut-out is that the damaged pipe is completely replaced, so the risk of a service failure due to SCC is eliminated. However, the pipeline must be shut down until the repair is completed. Sometimes, a complete shut-down is not practical and this constraint often governs the decision between pipe replacement and other repair options.

Grinding out cracks is done with a hand file or a power tool, as shown in Figure 4.6. Grinding is an effective repair method, but only if the stress-concentrating effect of the defect is eliminated, all damaged or excessively hard material is removed and the amount and distribution of metal removed does not significantly reduce the pressure-carrying capacity of the pipe [33].

When grinding out results in a metal loss exceeding that allowed by CSA Z662, a full-encirclement reinforcing sleeve can be used to restore the structural integrity of the pipe. As shown in Figure 4.7, full-encirclement reinforcing sleeves consist of two halves of a cylinder that are placed around the damaged area of the pipe and subsequently joined by welding the side seams. However, for these sleeves to be effective as permanent repairs for SCC-affected pipe, the non-welded ends of the sleeve must be sealed onto the pipe to prevent water from getting in between the pipe and the sleeve.

As discussed in Section 4.1, the coating used in a repair must effectively eliminate the conditions necessary for SCC growth.

4.3.3 Conclusions

On pipelines where "significant" SCC exists, investigative excavations and repairs cannot be fully relied on to prevent all service failures due to SCC until there is a reliable site selection process for locating near-critical SCC flaws.

We are concerned that SCC may not be detected unless effective nondestructive inspection techniques are used by qualified technicians.

Also, the repair method chosen must restore the integrity of the pipeline and eliminate the conditions necessary for further SCC growth.

Only coatings that have been proven effective in protecting pipelines from SCC should be used for repairs.

4.4 In-line inspection

For many years, in-line tools have been employed for the inspection and maintenance of pipelines. These tools, commonly referred to by the pipeline industry as “pigs”, travel inside the pipeline with the flowing product and perform various functions.

As a mitigative measure against SCC, the objective of in-line inspection (ILI) is to detect stress corrosion cracks and collect enough information so that a decision can be made as to whether a crack needs to be repaired.

This section discusses in-line tools with particular focus on, crack detection ILI technology and the challenges in the development and use of such technology.

4.4.1 In-line tools

In-line tools can be classified as utility pigs or instrumented pigs. Utility pigs perform strictly operation and maintenance functions (e.g., cleaning, batching, gauging). They contain no instruments. On the other hand, instrumented pigs, also known as “intelligent” or “smart” pigs, may contain various sensors, sophisticated electronics, onboard computers and recording devices that collect data which are later analyzed to reveal information about the condition of the pipeline.

Figure 4.8
Pig receiver

There are two types of instrumented pigs: configuration pigs and ILI pigs. Configuration pigs use onboard sensors to determine either the configuration of the inner surface or the shape and location of the pipeline. They are designed to provide information on the geometry and dimensions of the pipeline. On the other hand, ILI pigs apply nondestructive examination (NDE) methods to the pipe wall in order to detect conditions of the pipe wall that may affect the integrity of the pipeline.

Pigs are placed in and taken out of the pipe using launchers and receivers (see Figures 4.8 and 4.9). These devices usually allow pigging while the pipeline remains in service or “on-line”. When on-line pigging is not possible, pigging can sometimes still be done “off-line” by taking the line out of service, temporarily adding a portable pig launcher and receiver, running a pig then putting the line back into service.

In-line inspection tools have been successfully used in pipelines for over 30 years. In 1965, the first magnetic flux leakage (MFL) ILI tool was introduced in the United States. This tool was used to detect general corrosion in pipelines. Since that time, MFL tools have been refined and are now routinely used to detect metal loss due to corrosion. Another NDE technique, ultrasonics, has been successfully adapted for ILI for the detection of corrosion. More recently, this technique has also been adapted for ILI for the detection of cracks.

4.4.2 Crack detection ILI technology

The Inquiry showed that detection of SCC using special in-line inspection tools has considerable potential.

Figure 4.9
British Gas SCC pig being removed from a receiver

Crack detection ILI tools are designed to detect longitudinal cracks, including SCC, and provide information on their dimensions. With a reliable and accurate crack detection tool, such information can be used to locate critical and near-critical cracks so that they may be repaired. By providing information on the location, extent and severity of SCC on a pipeline, better decisions can be made regarding maintenance activities.

Crack detection tools use ultrasonic technology, which has been successfully used for many years to find cracks in a variety of other industrial applications. Ultrasonic waves are transmitted via transducers into the pipe wall. These waves are reflected when they encounter discontinuities (such as cracks) and a portion of their energy is reflected back as an ultrasonic signal. This signal is then processed and recorded for later analysis.

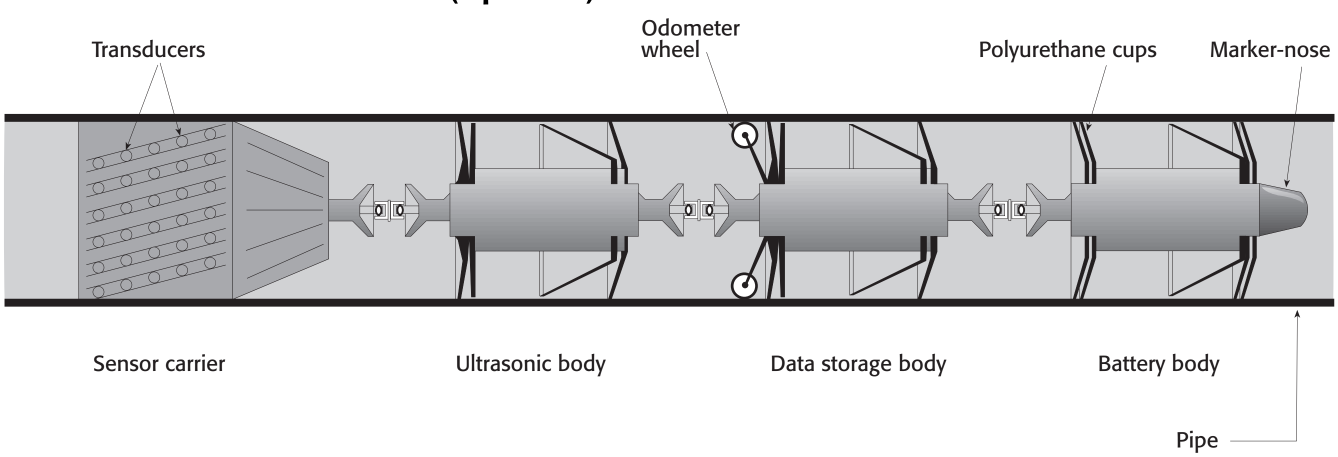
Examples of crack detection tools that are currently available or under development are illustrated in Figures 4.10 and 4.11. Table 4.3 summarizes some of the technical characteristics of these tools.

Currently, the evolution of crack detection ILI is at a stage where tools have been developed and are being offered for commercial use. In respect of the British Gas Elastic Wave Inspection Vehicle (EWIV) Mark II, TransCanada stated [35]:

> *The crack detection capabilities of the current EWIV (Mark II) have been proven on TransCanada's Line 100-2 as well as on other pipe systems. However, the data analysis techniques utilized to discriminate between injurious crack-like defects and non-injurious inclusions have limited the progress of the tool on specific pipeline steels with high reflector populations...*

Generally, results so far are promising in that the tools are finding cracks and the technology for distinguishing them from non-injurious

Figure 4.10
Schematic of a crack detection tool (Pipetronix)



Source: Adapted from endnote [34]

Table 4.3
Examples of in-line inspection tools currently under development or being tested

Company	**Pipetronix Ltd.**	**British Gas plc**		
Tool	UltraScan CD	MARK II	Interim MARK III	MARK III
Development stage / Date available	Advanced / Currently available [a]	Advanced / Currently available [a]	In development / End of 1996 [a]	In development / End of 1998 [a]
Technology	Ultrasonic / requires liquid couplant between the transducers and the pipe wall [d]	Ultrasonic / uses liquid-filled wheels to achieve coupling between the transducers and the pipe wall [i]	Ultrasonic / uses liquid-filled wheels to achieve coupling between the transducers and the pipe wall [i]	Ultrasonic / uses liquid-filled wheels to achieve coupling between the transducers and the pipe wall [i]
Runs in liquid lines?	Yes - uses product in the line as coupling agent [d]	Yes [b]	Yes [b]	Yes [b]
Runs in gas lines?	Yes - requires a liquid slug [d]	Yes [b]	Yes [b]	Yes [b]
Previous inspections	In Europe, liquid and gas pipelines [g]	In Canada and the US, liquid and gas pipelines [b]	–	–
Target size of SCC flaws that the tool must detect	30 mm length; 2 mm depth [f]	50 mm length; 1.5 mm depth [k]	50 mm length; 1.5 mm depth [k]	50 mm length; 1.25 mm depth [h]
Maximum inspection speed	1 m/s [d]	2 m/s [j]	2 m/s [j]	3.6 m/s [j]
Maximum inspection range	100 km [c]	45 km [j]	60 km [j]	150 km [j]
Nominal size(s) of tools	610 mm (24″) [d]	914 mm (36″) [j]	914 mm (36″) [j]	610 mm (24″) & 1067 mm (42″) [j]
Sizes of pipe that the tool can inspect with proper conversion kit	The 610 mm (24″) tool can be modified to cover 508 mm (20″) to 762 mm (30″) lines; In the second quarter of 1996, Pipetronix planned to release a tool that would cover pipe sizes ranging from 1016 mm (40″) to 1422 mm (56″) [d]	The 914 mm (36″) tool can cover 813 mm (32″) to 914 mm (36″) lines [j]	The 914 mm (36″) tool can cover 813 mm (32″) to 914 mm (36″) lines [h]	The 610 mm (24″) tool can be modified to cover 508 mm (20″) to 762 mm (30″) lines; the 1066 mm (42″) tool can cover 813 mm (32″) to 1219 mm (48″) lines (subject to conversion kits' availability) [h]
Other features / comments	German TÜV certified this tool as a replacement for hydrostatic retesting [e]	Has some ability to detect disbonded coating [l]	Will have more sensors than Mark II [j]; will have some ability to detect disbonded coating [l]	Gas bypass capability for gas line inspection / New electronics / Enhancement of the ability to detect disbonded coating [m]

References for the table

[a] CEPA Submission, Vol. 1, Issue 3, pp 2 & 9.
[b] CEPA Submission, Vol. 1, Issue 3, pp 3-5.
[c] CEPA Submission, Vol. 2, Appendix D, Tab 11, p 3.
[d] CEPA Submission, Vol. 2, Appendix D, Tab 11, p 5.
[e] CEPA Submission, Vol. 2, Appendix D, Tab 11, p 6.
[f] CEPA Submission, Vol. 2, Appendix D, Tab 11, p 7.
[g] CEPA Submission, Vol. 2, Appendix D, Tab 11, p 9.
[h] CEPA Submission, Vol. 2, Appendix E.
[i] British Gas Submission, Part B, p 3.
[j] British Gas Submission, Part B, p 7.
[k] British Gas Submission, Part B, p 11.
[l] MH-2-95 Hearing Transcript, 19 April 1996, p 597, line 27.
[m] MH-2-95 Hearing Transcript, 19 April 1996, p 593, line 10.

features is improving. It is expected that this will lead to newer generations of crack detection tools with enhanced capabilities in the near future.

Once a tool is available with proven reliability for detecting critical and near-critical cracks and the ability to distinguish between cracks and non-injurious features, it will greatly enhance a company's ability to maintain the integrity of a pipeline that is susceptible to SCC, or to any other cracking mechanism. The company will know with much greater certainty where repairs are necessary, rather than having to rely only on predictive models or hydrostatic retests. Better decisions can be made regarding the need for other mitigative action (e.g., recoating, selective replacement) and down-time will be reduced.

CEPA stated that crack detection tools, as they further develop, may be used to monitor crack initiation and growth, validate and enhance predictive soils models for use in non-piggable pipeline sections and possibly find areas where coatings have disbonded [36].

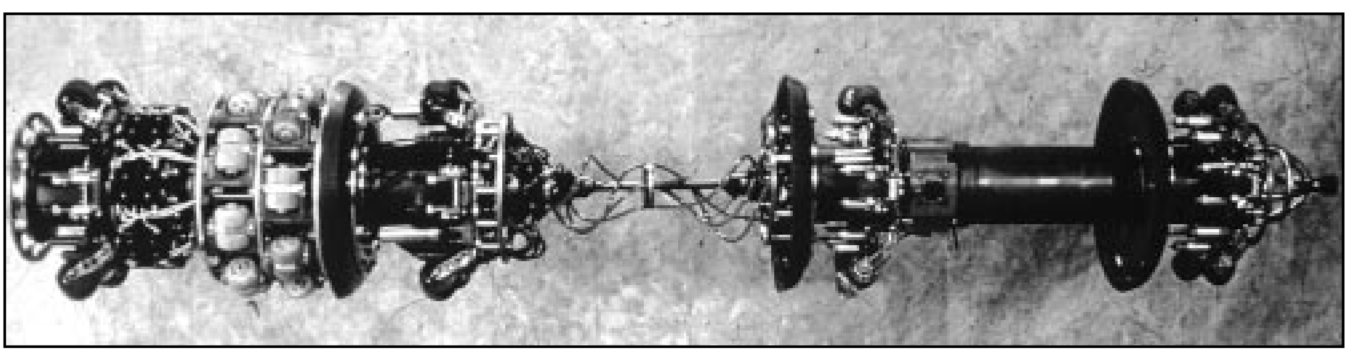
4.4.3 Challenges

While we are hopeful that crack detection ILI tools will evolve to a level of reliability comparable to that of hydrostatic retests in finding near-critical longitudinal cracks like SCC, we also recognize that there are challenges ahead for the industry and the manufacturers of these devices. These are some of the major challenges:

Technical challenges. An ILI tool must survive a 60 to 150 km journey through a buried pipeline without its sensors and sensitive electronics being damaged. To detect cracks, the sensors of the tools have to inspect the complete volume of metal in the pipe wall over long pipeline sections. Achieving this level of performance is not easy.

In order for the ultrasonic energy to be efficiently transmitted from the transducers to the pipe wall and back, the transducers must be coupled to the pipe. This is achieved by placing a liquid between the transducers and the pipe wall. In pipelines transporting liquid products, the product itself is used as a couplant. For gas lines, the ILI tool must

Figure 4.11
Photo of a crack detection tool



Courtesy of British Gas

CSA Z662-94, Oil and Gas Pipeline Systems
4.3.1.5

Consideration shall be given to designing pipeline systems to accommodate the use of internal inspection devices; items to be considered may include the location and sizing of scraper barrels, full opening mainline block valves, bend radii, and scraper guide bars.

either be in a slug of liquid or, as with the British Gas tool, have ultrasonic transducers coupled to the pipe through liquid contained in wheels that ride on the inside surface of the pipe. The use of a slug of liquid, usually water, challenges gas pipeline operators to deal with significant operational problems, because the line has to be taken out of service and, after pigging, the water must be removed and disposed of. The British Gas tool, however, eliminates this problem.

After the inspection, the pig is taken out of the line and the information storage package is removed for validation and preliminary analysis. After the data are checked in the field for quality and to determine whether any equipment failures occurred, it is sent to the ILI tool manufacturer for processing and detailed interpretation. The ILI data interpretation consists of many distinct stages, ranging from data reconstruction to final sizing of the defects that will ultimately be recommended for excavation. The processing of the data is carried out by specialists using specially developed computer software. They review the information and look for patterns which may represent a crack. This process can take some months to complete before the final results are delivered.

The interpretation of the inspection data and its dependence on human skills is the most critical and challenging part of the crack detection process, as cracks and other non-injurious metallurgical features present in the steel must be reliably distinguished from one another and defects must be sized and ranked. Generally, the smaller the size of crack that needs to be detected, the greater the likelihood of a "false-call" (a non-injurious feature interpreted as a crack). British Gas indicated that, according to laboratory experience and field trials, the *"... defects which have approached the dimensions likely to lead to pipeline rupture have always been detected by the system. A more pertinent question is whether the procedures used to analyze the data lead to accurate recognition of these flaws."* [37] ILI tool developers are currently investing a lot of effort into the improvement of data analysis techniques in order to better discriminate cracks from non-injurious features.

Ability of major Canadian pipelines to accommodate ILI tools. This is a challenge in that not all pipelines can accommodate in-line tools. Many older pipelines in particular fall into this category. Various features of pipelines (types of valves, bend radii, multiple wall thicknesses, different pipe diameters) can restrict the passage of pigs. While some of these lines can be modified to accommodate internal tools, the costs may be very high.

Many pipeline systems in Canada were constructed before ILI tools were developed. As a result, the original designs did not take into account the need to provide for in-line inspection. Currently, CSA Z662 requires that internal inspection capability be considered in the design of new pipelines.

The total length of pipeline owned by CEPA member companies in Canada is 55 000 km, of which 40 per cent (22 000 km) is smaller than 508 mm (20 inches) in diameter. CEPA indicated that, for the foreseeable future, crack detection tools will be targeted at pipelines 508 mm in diameter and larger [38]. Of the 33 000 km of pipelines 508 mm or larger in diameter, about 15 000 km are currently capable of accommodating on-line inspection, while some 18 000 km would require modifications (i.e., installation of launcher/receiver traps and valve replacements) before being able to be inspected on-line. The cost of these modifications is estimated to be about $270 million. Of the total 55 000 km of pipeline, a small percentage is not adaptable for internal inspection, and other detection methods would be required [39].

TransCanada indicated that it has begun a multi-year program for the installation of pig launchers and receivers on high-risk portions of its pipeline system where these facilities do not already exist and will ensure that all new lines will be constructed to allow the passage of ILI tools [40]. In addition, TransCanada will run magnetic flux leakage and crack detection pigs off-line through the high risk sections of its system that cannot currently accommodate on-line pigging [41].

TransCanada forecast that, by the end of 1996, over 3 450 km of pipe on its system would be able to accommodate on-line inspection [42]. TransCanada further stated that, with the exception of the Youngstown portion of line 100-1, all SCC-susceptible lines on its system are capable of accommodating an in-line inspection tool [43].

Industry commitment to tool development. CEPA stated that significant progress has been made in the development of crack detection tools since 1993 [44]. It also indicated that pipeline companies have supported the development of ILI tools for the detection of cracks by making financial commitments to research and by providing operational experience to the tool developers [45]. CEPA is encouraging the development of different ILI tools so that its members may benefit from having access to a wide range of technologies [46].

CEPA, PRC*I*, GRI and British Gas are funding ($7.4 million between 1996 and 1998) a new generation of crack detection ILI tools being developed by British Gas [47]. An interim 914 mm (36 inch) tool is forecast to be available by the end of 1996, while 610 mm (24 inch) and 1066 mm (42 inch) tools are expected to be available by the end of 1998. With the appropriate conversion kit, these tools could be modified to fit pipelines ranging from 508 mm (20 inches) to 1219 mm (48 inches) in diameter.

TransCanada foresees crack detection tools becoming an effective substitute for hydrostatic retesting. During 1996 and 1997, TransCanada will be carrying out tests using a British Gas crack detection ILI tool in order to qualify it as an alternative for hydrostatic retesting. Several sections of pipeline will be pigged and, after the resulting crack indications are investigated and repaired, hydrostatic retests will be done to determine if the tool missed any near-critical defects [48].

Cost. Some preparation of the pipeline is required before an ILI tool can be run through the pipe. The line must be cleaned and checked to make sure there are no obstructions in the pipeline. There is a cost associated with these preparations, as there is with the actual inspection.

In order to accurately inspect the pipeline for defects, the speed of smart pigs must be maintained within a specific range. For pigging liquid lines, pipeline operators do not have to significantly reduce throughput, because the average speed of liquid flow is low. For gas pipelines, since the average flow rate is much higher than in liquid lines, operators must considerably reduce throughput, which adds significant costs to the in-line inspection operation. In order to overcome this, British Gas is currently developing gas bypass systems which will allow a portion of the flow to go through the inspection tool, thereby reducing the loss of throughput. This loss of throughput can be further reduced by pigging pipelines during off-peak periods of operation.

TransCanada believes that if ILI tools prove to be reliable, they will be cost-competitive with other SCC detection techniques such as investigative excavations and hydrostatic retesting [49].

4.4.4 Conclusions

While we are encouraged by the commitments, efforts and progress made by pipeline companies and crack detection tool developers, we find that crack detection ILI technology has not yet fully proven its capability to reliably detect critical and near-critical cracks and distinguish them from non-injurious features and thus be used as a substitute for hydrostatic retesting.

Assuming a reliable crack detection tool becomes available, it could be used to provide a company with accurate information on the condition of its pipeline. Such information will allow for better decisions regarding the need for mitigative action and significantly enhance the effectiveness of other mitigative measures in preventing service failures or reducing the consequences of such failures.

The ability of a pipeline to accommodate the passage of in-line inspection tools significantly facilitates the maintenance of the integrity of that pipeline, not only with respect to SCC, but with most integrity issues.

Recommendation

4-4 We **recommend** that the Board require that new large diameter transmission pipelines be designed and constructed to accommodate the passage of in-line inspection tools.

4.5 Pressure reduction

A critical area of examination in the Inquiry was the possibility of managing SCC by limiting or reducing operating pressure. The issue of pressure reduction is important because, as discussed in Chapter 3, the operating pressure of a pipeline is generally the primary source of circumferential stress in the pipe and stress is one of the three conditions necessary for SCC.

The effects of stress reduction on crack initiation and crack growth were discussed in detail in Chapter 3. The relationship between stress and critical crack size is discussed in Section 4.6 on hydrostatic retesting. The general findings are summarized below:

Crack initiation. Lower stress levels cause fewer cracks to initiate. However, a threshold stress level below which near-neutral pH SCC will not initiate has not yet been determined.

Crack growth. It is not known whether changes in stress levels, within the normal range of operating stress levels for pipelines, affect crack growth rate. As with crack initiation, a threshold stress level below which near-neutral pH SCC will stop growing has not yet been determined.

Critical crack size. When operating stresses are reduced, it takes a larger crack to produce a pipeline failure (Figure 4.12). And since it will take more time for a crack to grow to that larger critical size, the safe operating life of the pipeline before the failure of SCC and other longitudinal flaws is increased.

Where relevant, these specific effects of stress reduction are discussed below for pipelines with and without effective coatings.

4.5.1 Pipelines with effective coatings

As discussed in Section 4.1, the use of effective coatings such as FBE can prevent the initiation of SCC. If no stress corrosion cracks initiate, the effects of stress reduction on crack growth and critical crack size become irrelevant. There will not be any service failures due to SCC. Thus, for existing or new pipelines that have effective coatings, a reduction in operating stress would not be of any benefit.

4.5.2 Pipelines without effective coatings

For pipelines without effective coatings, the occurrence of SCC depends in large part on the performance of the coating. If the coating does not disbond, SCC will not occur and stress reduction will not be necessary. Where coatings disbond, SCC may be a concern. As noted earlier, lower stress levels cause fewer cracks to initiate. The fewer cracks there are, the less likely they are to coalesce and the longer it will take for them to grow to a critical size. However, since the relationship between stress and crack growth rate has not been established, it is difficult to quantify any benefit that might be derived from a reduction in the operating stress of a pipeline in terms of its effect on crack growth.

It is, though, known that a larger critical crack size would be required to produce a failure. Service failures due to SCC would therefore be delayed and possibly reduced in number.

However, unless the operating pressure is set below the level needed to produce the minimum stress for crack initiation or for crack growth, there can be no assurance that service failures will not eventually occur. Such threshold values have not yet been determined and may be too low to be used for practical purposes. Therefore, other measures such as hydrostatic retesting would still be required to eliminate SCC related service failures, although not as frequently as if the operating stress were higher. Rather than lowering the operating stress on the pipeline, a company could achieve the same result - eliminate SCC related service failures - by retesting more frequently. In the long-term, the only benefit from the reduction in stress would be the cost savings from reducing the frequency of testing.

Such savings would likely be much less than the cost of a sustained lowering of the operating pressure on pipelines. CEPA estimated the cost of limiting gas pipeline operating pressure to 72 per cent SMYS to be in excess of $1 billion for the replacement of 500 MMcfd of lost capacity at the Alberta/Saskatchewan border [51]. In its evidence, CGA also stated [52]:

> *If the TransCanada PipeLines (TCPL) system was derated to 72% SMYS, LDCs* [Local Distribution Companies] *would be unable to deliver all the gas required by their firm customers. A peak day shortfall of about 140 MMcfd would be created in Ontario and Quebec. Derating to 64% SMYS would create a peak day shortfall of about 480 MMcfd to firm customers. Interconnect pipelines to Eastern Canada are insufficient to meet these requirements. A loss of deliverability of this magnitude would have severe social, safety and economic impact on Eastern Canada.*

Until such time as replacement capacity is in place, there would be significantly less gas flowing to Eastern Canadian and U.S. markets and the cost of transporting that gas would be higher.

Regardless of the effect of stress reduction on crack initiation and growth, there is no question that, when operating stresses are reduced, it requires a larger crack to cause a pipeline failure (Figure 4.12). And since it will take more time for a crack to grow to that larger critical size, the safe operating life of the pipeline against the failure of SCC and other longitudinal flaws is increased. As an example, calculations of critical crack size based on the CorLas™ model showed that reducing the operating stress from 77 to 64 per cent SMYS for a particular pipeline would extend the time to failure by some 25 months [53]. When used together with a hydrostatic retesting program or an in-line inspection program, stress reduction would reduce the required frequency of retesting or inspection.

However, as a long-term mitigative measure, a reduction in operating stress will not prevent service failures, it would only delay them. Stress reduction is therefore not supported as an effective permanent mitigative measure for SCC-affected pipelines.

However, the effect of stress reduction on critical crack size suggests it should be considered as a temporary measure for sections of a pipeline system where there is a threat of imminent failure. For example, when a failure occurs on a section of a pipeline, the rupture may indicate that the company's integrity management program is inadequate for that section and that future failures may occur in that vicinity. In such a case, the operating stress should be reduced until the integrity of the section can be re-established. Similarly, where an investigation shows that a section contains near-critical SCC, the pressure in the line should be reduced until a hydrostatic retest is carried out to remove those defects.

Where a company decides that a hydrostatic retesting program is necessary because the integrity of sections of the pipeline system is in question, a reduction of the operating stress would be desirable. Until every affected section of a pipeline system has been retested at the required test frequency, there may be a threat of imminent failure and it may be appropriate to lower the operating stress in those sections. The amount of the reduction will depend on how quickly all sections can be tested.

4.5.3 Conclusions

For existing or new pipelines with effective coatings, a reduction in operating stress will not be of any benefit in terms of preventing service failures due to SCC, since SCC is not likely to occur.

For pipelines without effective coatings, we believe that a general reduction in allowable operating pressure would not be a logical or effective response to the SCC problem. Three basic factors support this conclusion:

- In terms of preventing service failures, the benefits, if any, from the consequent lowering of pressure cannot be determined from the available research and field information. Pressure reduction does not remove existing cracks, which may grow to failure.
- The potent environment necessary for SCC exists at only certain locations along a pipeline. Our findings in this respect are set out in Section 3.4. Consequently, a general reduction in pressure would be a very inefficient mitigative approach and would restrict pipeline capacity with severe operational, economic and social consequences.

- We find that there are a number of other measures, as described elsewhere in this Chapter, which are more systematic, efficient and effective in mitigating SCC and thereby enhancing public safety.

We believe that pressure reduction can be effective as a temporary measure to ensure safety while other detection and repair measures are implemented. The basis for this conclusion is that a lowering of pressure increases the size to which a crack can grow before failure occurs.

Recommendation

4-5 **We recommend that the Board require that pressure reduction be included as part of all SCC management programs and considered for use:**

a) in combination with investigative excavations and other mitigative measures such as hydrostatic retesting and in-line inspection; and

b) as a temporary measure where there is a threat of imminent failure, in which case it should be maintained until the integrity of the pipeline is re-established.

4.6 Hydrostatic retesting

Pressure testing is widely used in the pipeline industry to demonstrate the structural integrity of a pipeline and to establish a safe operating pressure for it. Various pipeline codes and standards, including CSA Z662, require a pipeline to be able to sustain a pressure greater than its intended operating pressure. Regulatory authorities generally require a pipeline to undergo a successful pressure test before they will grant an operating permit or licence for a newly constructed pipeline.

Water is most commonly used as the pressure test medium, in which case the test is referred to as a hydrostatic test. A section of pipeline is filled with water and then the water pressure is raised above the level at which the pipeline is intended to operate. The pressure is held for a prescribed amount of time and the test is considered successful when the pipeline is able to sustain the test pressure for that time period. A successful hydrostatic test is an assurance that the pipeline is safe to operate at its regular operating pressure. Its structural integrity has been demonstrated.

There can be reasons to use a hydrostatic test other than when a pipeline is first put into service. If one failure or a series of similar failures were to occur on an operating pipeline, a hydrostatic retest could be used to check the structural integrity of the pipeline. The retest would help determine if the pipeline is fit for continued operation.

However, if a pipeline has defects that grow over time, such as stress corrosion cracks, a successful retest gives an assurance that the pipeline can be operated safely for a limited time only. In other words, the pipeline will be safe to operate only until the defects grow to that size where they may cause the pipeline to fail. If the defects grow to that critical point, the pipeline could fail while it is in service. Before that point is reached, another hydrostatic retest should be conducted. Consequently, for defects that develop over time, it may be necessary to conduct hydrostatic retests over the remaining life of the pipeline. When they are used in this way, hydrostatic retests are considered a mitigative measure for pipelines that have SCC. Hydrostatic retesting eliminates major defects that may cause a failure in service and validates the structural integrity of the pipeline at the test pressure level.

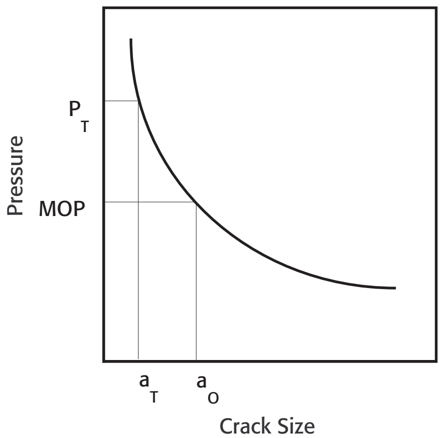
In the previous Inquiry, the Board was concerned that hydrostatic retests may themselves have long-term effects that are harmful to the integrity of a pipeline. The Board expressed the concern that the growth of cracks at the high stresses reached during hydrostatic retesting was not fully understood; in particular, that the hydrostatic retest itself might cause some defects to grow but not fail during the retest. In the current Inquiry, the Panel reviewed the evidence pertaining to these concerns and evaluated the effectiveness of hydrostatic retesting in preventing service failures caused by SCC, immediately following a retest and in the long-term.

4.6.1 Effectiveness at preventing service failures

While a hydrostatic retesting program may offer an effective mitigation tool for SCC susceptible pipelines, it can also cause significant operational difficulties because the line must be taken out of service for some time. Much has to be done to prepare for and conduct a hydrostatic test. Test heads must be installed and enough water to fill and pressurize the test section must be available. During the test, the time needed to find small leaks contributes to the down-time, as does repairing and cleaning up after any leaks or breaks. After the test, the water may have to be treated before it can be disposed of. Finally, the line must be emptied of water and put back into service.

In addition, hydrostatic retesting can be costly. For the duration of the test, the pipeline is out of service. The indirect costs associated with loss of throughput will depend on the operational flexibility of a system. In addition, there are the direct costs of the test, which, according to CEPA, are approximately $26 000 per kilometre ($780 000 for a 30 kilometre valve section), with repairs costing $75 000 per defect, for a 1067 mm (42 inch) diameter line [54]. These costs are incurred each time a retest is conducted.

Figure 4.12
Pressure vs. critical crack size



P_T = hydrostatic test pressure
MOP = maximum operating pressure
a_T = critical crack size at P_T
a_O = critical crack size at MOP
a_O - a_T = margin of safety for crack growth after test

CEPA identified two purposes for hydrostatic retests in the management of the integrity of SCC-affected pipelines [55]:

1. *To remove cracks which are approaching dimensions that would fail in-service in the near term, and*
2. *To provide a safety margin against in-service failure for surviving sub-critical cracks until the next test.*

In addition to these objectives, a hydrostatic retesting program should also maintain the long-term integrity of the pipeline by minimizing subcritical crack growth and pipe yielding during each test.

The effectiveness of hydrostatic retesting in meeting these three objectives, and hence in preventing service failures, is discussed in the following sections.

4.6.2 Removal of near-critical cracks

Laboratory research and decades of field experience have proven that hydrostatic tests effectively remove longitudinal defects from pipelines and that the higher the test pressure, the smaller the defects that remain (e.g., [56], [57], [58]). By testing the pipeline at a pressure higher than the maximum operating pressure, defects that might lead to failure in service are removed, as the higher test pressure will force them to the critical failure stage. Consequently, the defects that remain in the pipeline after a hydrostatic test are smaller than the critical size for failure at the operating pressure (Figure 4.12).

While hydrostatic testing is effective in removing longitudinal cracks, it is important to note that it is not always effective in removing defects that are oriented along the circumference of the pipe. As discussed in Chapter 3, internal pressure causes a stress in the longitudinal direction that is about one-third to one-half the circumferential stress. Since it is the longitudinal stress that acts on circumferential cracks, the stress from a hydrostatic test on a circumferential crack will not normally be high enough to cause a failure. Consequently, hydrostatic retesting is not an effective mitigative measure against failures caused by circumferential SCC.

4.6.3 Safe retest interval

Following the initial SCC failures on the TransCanada system, hydrostatic retest frequencies were selected on the basis of field experience. For example, from 1986 to 1992, the retest frequency for TransCanada's line 100-2 in Northern Ontario was 2 to 3 years based on recommendations from Battelle Memorial Institute [59]. This was a conservative retest interval that was likely based on field experience with high pH SCC in the U.S. If the valve section passed on the first hydrostatic retest, the interval was increased to 4 to 5 years.

Given the significant increase in the understanding of crack growth and crack growth rates for near-neutral pH SCC since that time, a more analytical approach can be used to determine a safe hydrostatic retest interval. As will be discussed below, this analytical approach for determining a safe retest interval will rely on establishing an appropriate failure criterion and validated crack growth rate for the specific pipeline under consideration.

Figure 4.13 shows the relationship between crack size and time. At the end of a hydrostatic retest, small non-critical cracks will remain. Over time, these cracks may grow and, if their growth goes unchecked, the largest could eventually cause a failure while the pipe is in service. The key is to find and remove the large cracks before they cause a failure in service, meaning that the pipeline must be hydrostatically retested again before a crack reaches the critical size. The margin of safety after a hydrostatic retest is determined by the difference between the size of crack that will fail at the operating pressure of the pipeline and the size of crack that remains after the retest. The greater the difference between the test pressure and the maximum operating pressure, the greater the difference between these two crack sizes and the greater the margin for growth before a failure occurs in service.

CEPA stated that [60]:

The hydrotest interval is determined based on three considerations:

- *the size of the surviving flaws from the previous hydrotest,*
- *the crack growth rate and the growth process, and*
- *an appropriate failure criterion.*

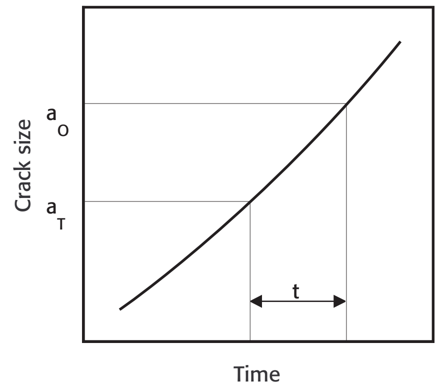
The failure criterion establishes sets of data that represent the sizes of surviving flaws (or, conversely, the critical crack sizes) at the hydrostatic test pressure and at the operating pressure. The sets of data represent two curves of critical crack sizes for the two pressure levels (e.g., see Figure IV.3, Appendix IV). As noted by TransCanada [61], *"The difference between these curves represents the amount a defect must increase to go from surviving a hydrostatic retest to becoming critical at operating pressures."* Since the data generated depend on the failure criterion used, it is critical that the failure criterion be appropriate for the particular pipeline.

With respect to crack growth rates, values have been estimated from laboratory experiments and field data. In order that a safe hydrostatic retest interval may be determined, it is critical that the crack growth rate be valid for the particular pipeline.

The selection of an appropriate failure criterion and a validated crack growth rate are discussed in more detail below.

Failure criterion. In order to determine the margin for crack growth between hydrostatic retests, the size of a crack that can survive a hydrostatic test and the size of a crack that will fail at the maximum operating pressure should be known with reasonable certainty. Leis cautions that *"… failure criteria that are conservative inherently with*

Figure 4.13
Crack size vs. time



a_T = critical crack size at hydrostatic test pressure

a_O = critical crack size at maximum operating pressure

a_O - a_T = margin of safety for crack growth after test

t = time required for crack of size a_T to grow to a_O

At the end of a hydrostatic test, the largest remaining crack is a_T. In order that a crack of size a_T does not fail in service, the pipeline must be tested before time t has elapsed. The difference between a_O and a_T is a measure of the margin of safety for crack growth. As may be seen from Figure 4.12, the larger the difference between the test pressure P_T and MOP, the larger the margin of safety between a_O and a_T.

respect to predicted failure pressure can be quite nonconservative in applications to estimate the size of flaws that remain in the pipeline...." [62]

Failure criteria are generally intended to predict safe, or conservative, operating pressure levels for known defect sizes; i.e., they tend to under-estimate the pressure at which a known defect will fail. However, when calculating the safe interval between retests, the test pressure is known and the critical defect size is inferred from that pressure. A failure criterion that under-estimates failure pressure will, in turn, under-estimate the critical crack size for the test pressure. If the critical crack size at the test pressure is under-estimated, the remaining margin for crack growth during service is over-estimated. Consequently, the safe operating interval between tests is over-estimated. It is important therefore to be aware of the level of conservatism associated with the application of a failure criterion. As stated by CEPA [63], *"Using an approach that is overly conservative can lead to problems in assessing the remaining life and making decisions on appropriate mitigative actions."*

Another concern with failure criteria is the inconsistency of the results. It is difficult to rely on a failure criterion whose application results in levels of conservatism that vary over a wide range of values. Over-conservatism and inconsistency could result in over-estimating the safe operating interval between hydrostatic retests.

In order to evaluate the conservatism and consistency of the various failure criteria discussed in the course of the public hearing, CEPA provided failure pressure calculations for 14 crack sizes and compared the predicted values to the observed failure pressures [64]. The details of the analysis are included in Appendix IV. The results indicate that the application of the various failure criteria can yield very conservative and sometimes inconsistent results.

As noted in Appendix IV, the predictive capability of a failure criterion improves if the criterion is appropriate for the particular situation under consideration. The assumptions underlying a failure criterion, as well as the data used to verify the criterion, must be applicable to the situation under analysis.

Once a failure criterion has been selected, the critical crack sizes at the test pressure and at the operating pressure can be determined. Generally, the assumption of an infinite crack length will result in conservative estimates of hydrostatic retest intervals.

Crack growth rate. Once the margin for crack growth has been calculated, it is a simple matter to divide it by the crack growth rate to determine the safe operating interval between retests. However, selecting an appropriate value for crack growth rate is not an easy process. Published laboratory data indicate that crack growth rates can vary from 10^{-9} mm/s (.03 mm/yr) to 10^{-6} mm/s (30 mm/yr) and suggest that SCC growth is characterized by periods of dormancy and rapid growth [65].

CEPA's position is that a time-averaged growth rate can be developed for a pipeline and used in the calculation of a safe retest interval and recommends 2×10^{-8} mm/s (0.6 mm/yr) as a conservative value [66]. However, this value may not be applicable to all pipelines. It is important to understand how the value of 2×10^{-8} mm/s has been arrived at. This value represents the maximum time-averaged crack growth rate observed on line 100-2 of TransCanada's pipeline system and was derived from measurements of crack growth from failure investigations [67]. It would therefore apply to pipeline systems whose environment, metallurgy and operating conditions are similar to line 100-2.

If the conditions for a particular pipeline were not similar to those of TransCanada's line 100-2, the use of 2×10^{-8} mm/s may be inappropriate and additional safety factors may be necessary for the calculation of a safe retest interval. For example, if the normal stress fluctuations on a particular pipeline were considerably higher than those on the TCPL system, the use of the value of 2×10^{-8} mm/s for crack growth could over-estimate the safe operating life before the next retest.

CEPA recommends that, if a different growth rate has been validated for a specific pipeline, that value should be considered for use. However, such validation is not easily achieved. As noted earlier, laboratory data can vary over a wide range. Field data would be preferable, but are not as easy to obtain. In the case of TransCanada, field investigations of actual failures were required over many years of operation. It may be difficult to arrive at a reliable and validated crack growth rate for some pipelines and conservative assumptions may become necessary. This situation will require a careful analysis by individual pipeline companies.

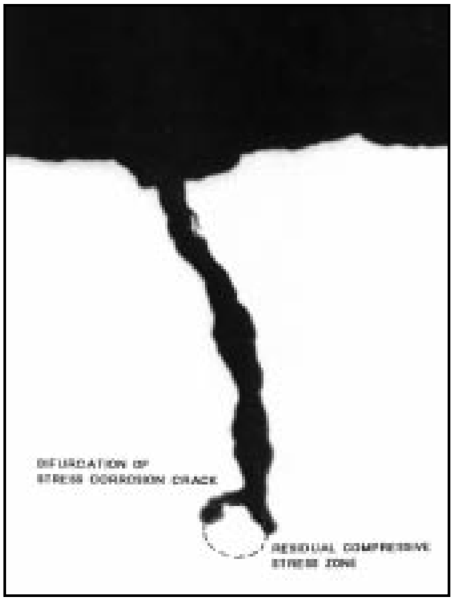
4.6.4 Long-term integrity

The third objective of a hydrostatic retesting program is to maintain the long-term integrity of the pipeline. The Inquiry examined two concerns about the effects of repeated hydrostatic testing on the long-term integrity of a pipeline: the permanent expansion of the pipe as a result of repeated hydrostatic retesting at stress levels above the pipe's yield strength; and the continued growth of subcritical cracks.

Pipe expansion. Pressure testing at stresses at or above SMYS can result in permanent expansion of the pipe. If this expansion becomes excessive, the integrity of the pipeline could be reduced. Permanent expansion in a joint of pipe could occur if the hoop stress produced by the test pressure exceeds the actual yield strength of that joint. For most pipelines, however, the mechanical properties and dimensional tolerances of the pipe are such that excessive expansion is unlikely, even with high pressure tests.

CEPA states that pressurizing a test section up to 110 per cent SMYS would not result in any significant permanent expansion of the pipe and would therefore not affect the future integrity of the pipeline.

Figure 4.14
Cross-section of a stress corrosion crack after hydrostatic testing and one year of service



Source: Endnote [50]

Historical data on high pressure tests have not indicated any excessive expansion, which supports CEPA's position. However, to ensure that any localized expansion is avoided, high pressure tests should be closely monitored using a pressure-volume plot.

Growth of subcritical cracks. The concern with the growth of subcritical cracks is that a hydrostatic retest might cause some cracks to grow but not fail during the test, and that the number of near-critical cracks may gradually grow with repeated hydrostatic retests and reduce the long-term integrity of the pipeline system.

CEPA's position is that, during a hydrostatic retest, shallow cracks are unlikely to grow; growth would be confined to cracks approaching 50 per cent of the wall thickness, but they would not grow beyond the critical size [68]. In its submission, CEPA refers to studies that support the position that shallow cracks do not exhibit any crack tip changes during a hydrostatic retest [69] and that deeper cracks that survive the test have blunted ends with associated plastic deformation, which forms a residual compressive stress zone at the crack tip [70]. As a result, the crack will have to either travel through the compressive stress zone at a slower rate, or, as indicated in Figure 4.14, travel around the zone by forking out around it (bifurcation). Either way, crack growth is slowed down until the crack has travelled past the compressive stress zone.

Additional studies by TransCanada support CEPA's position. A TransCanada study on the effect of repeated hydrostatic tests on flaws in ERW pipe (Youngstown) showed that any crack growth resulting from the tests was insignificant [71]. As well, TransCanada pointed to the decreasing trend in test failures on subsequent retests as proof that hydrostatic retesting does not adversely affect the long-term integrity of a pipeline [72].

A related study that provides additional insight into the behaviour of cracks during a hydrostatic test is the AGA NG-18 Report No. 194 [73], which is a study of ductile flaw growth as a function of various hydrostatic test parameters, pipe and flaw geometric properties, material properties and hydrostatic test conditions. CEPA stated that this report validates a testing procedure that maximizes the removal of near-critical cracks and minimizes damage to the pipeline [74].

A key finding of the NG-18 Report No. 194 is that a maximum test pressure level between 100 and 110 per cent SMYS appears to provide a good balance between removing large flaws that might cause failure in service and producing growth only in a relatively few near-critical flaws. As well, the study found that a maximum pressure hold time of one hour is a good upper limit, as it causes a very high percentage of the near-critical flaws to fail, while still minimizing the growth of the remaining flaw population. On this basis, CEPA recommended a one-hour high pressure test between 100 and 110 per cent SMYS, followed by a leak test at no more than 90 per cent of the peak test pressure [75]. The NG-

18 Report No. 194 indicates that there should be minimal flaw growth at this reduced pressure during the leak test.

Another key finding of the study is that a given test pressure will cause growth in only a limited range of flaw sizes below those it causes to fail. At one extreme are the smallest cracks, those that fall outside the low end of this range. They will not experience any growth at the test pressure. At the other extreme, the very deep cracks that fall outside the high end of the range will fail either due to immediate crack growth as the pressure is raised, or to time-dependent creep growth during the hold period of the test. In between the two extremes of very small and very large crack sizes are the cracks that will grow by stable tearing, but not fail. The study found that the higher the test pressure, the narrower the range of these flaw sizes that will grow but not fail.

While CEPA is recommending the same test scenario for all pipelines, we are concerned that the scenario, as recommended in the NG-18 Report No. 194, was developed specifically for gas transmission lines operating at or near 72 per cent SMYS, with daily pressure cycles of 10 per cent of the maximum operating pressure. The scenario may not be appropriate for liquid pipelines or even other gas pipelines where operating conditions are significantly different. The study was also based on submerged-arc welded pipe in grades X52 to X70 with yield-to-ultimate ratios less than 0.90 and so the results may not apply to pipes with significantly different material properties.

The study indicates that pipelines that may have SCC can be hydrostatically retested without causing significant subcritical crack growth, as long as the test is properly designed for the particular pipeline under consideration. The appropriate test scenario may differ from pipeline to pipeline, depending on the material properties and specifications of the pipe, as well as the operating conditions of the pipeline. It is therefore important that pipeline companies make sure that the assumptions and data from the study apply to their own systems before adopting the conclusions and recommendations of the AGA NG-18 Report No. 194.

4.6.5 Conclusions

We believe that, where it has been determined that there is a reasonable risk of service failures due to SCC over a long section of a pipeline, hydrostatic retesting is currently the only reliable way to prove the integrity of the pipeline for continued operation.

A hydrostatic retesting program can effectively prevent service failures resulting from longitudinal SCC provided:

- the hydrostatic retest removes all cracks whose length and depth are approaching the critical point where they could cause a failure under normal operating conditions;

- the interval between retests is less than the time required for any crack that remains after a retest to grow to critical size; and
- the retest does not reduce the long-term integrity of the pipeline by causing permanent expansion and substantial subcritical crack growth.

Determination of a safe retest interval depends on establishing an appropriate failure criterion and validated crack growth rate for the specific pipeline under consideration. We consider that, where a crack growth rate has not been validated for a pipeline, conservative values for crack growth rate should be assumed when calculating a hydrostatic retest interval.

Unless there are reliable historical data on typical crack dimensions at failure, the minimum margin of safety for crack growth after a retest should be used to arrive at a conservative value for a safe retest interval.

Subcritical crack growth can be minimized during a hydrostatic retest provided the test pressures and test durations are appropriate for the particular pipeline under consideration.

We note that hydrostatic retesting is not currently addressed in the CSA Z662 standard as an option for maintaining pipeline integrity, and that the findings from recent studies on hydrostatic testing (e.g., AGA NG-18 Report No. 194) are not reflected in the current requirements of that standard.

Recommendations

4-6 **We recommend that the Board require that, where a hydrostatic retest program forms part of an SCC management program, it be properly designed for the particular pipeline under consideration. The design should take into account factors such as the material and geometric properties of the pipe, the operating history of the pipeline, its future operating conditions and field and laboratory data on crack sizes and crack growth. Where reliable data are not available, conservative assumptions should be made.**

4-7 **We recommend that the Board request that the CSA Technical Committee on Oil and Gas Industry Pipeline Systems:**

a) incorporate, in the next edition of the CSA Z662 Oil and Gas Pipeline Systems standard, requirements for hydrostatic retesting as an option for maintaining pipeline integrity; and

(b) amend the current pressure testing requirements of the standard in light of the findings from recent studies on hydrostatic testing.

4.7 Selective pipe replacements

Selective or proximity pipe replacements involve replacing sections of the pipeline that are susceptible to "significant" SCC, where those sections are close to critical locations along the pipeline route. Critical locations may include: dwelling units, roads, railways, places of public assembly, sensitive environmental areas and sites of special significance to people.

Selective pipe replacements lead to service interruptions and are very costly. For example, it costs about $1400 per metre to replace 508 mm (20 inch) diameter pipe and approximately $3200 per metre to replace 914 mm (36 inch) diameter pipe [76]. CEPA stated that selective pipe replacements *"...are a repair option that would apply to SCC-susceptible areas only where other mitigative measures are determined to be unacceptable."* [77]

4.7.1 Pipe replacement length

When sections of a pipeline are considered for selective replacement, a sufficient length of pipe must be replaced (Figure 4.15) so that the critical locations are protected from the consequences of a failure. In order to determine how much pipe should be replaced, it is important to be able to predict the potential hazards associated with a

Figure 4.15
Selective pipe replacement

pipeline failure and the consequences that would arise from such hazards.

CEPA stated that *"…the appropriate distance criterion* [for selective replacements] *depends heavily on the service fluid being transported, but in all cases will aim to minimize the probability that identified consequences will accrue to people, property or environmental resources."* [78] For example, in the event of a fire resulting from the failure of a natural gas pipeline, residents of dwellings in close proximity to the pipeline should be protected. This would involve replacing a sufficient length of pipe such that any failure due to SCC on the original pipe will be far enough away from the dwelling units so as not to harm the residents.

4.7.2 Modelling of hazards and consequences

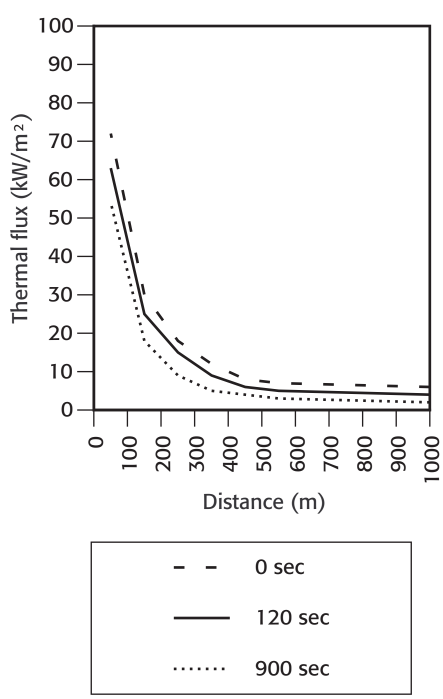
For oil and gas pipelines, the severity of the consequences of a pipe rupture is related to the diameter and operating pressure of the pipeline, the type of hydrocarbon involved and the size of the release.

In order to determine the effects of a hazard due to a failure, the characteristics of the release and its immediate and contingent effects must first be estimated using various types of models and then the consequences of such a release on people and property must be predicted and analyzed. The complexity of such models will vary depending on the hydrocarbon involved and the conditions under which it is released. For example, the models used to study the release and consequences of toxic sour gas are substantially different than the ones used for crude oil.

When estimating the consequences of a natural gas pipeline rupture which has ignited, it is necessary first to model the characteristics of the fire and the associated thermal radiation (heat) resulting from the fire and then to assess the effects of the thermal radiation on people and property. Based on such models, adverse effects on people and property can be estimated as a function of distance and then a "safe" distance can be established, beyond which no harmful consequences would occur [79].

Figure 4.16 shows one example of the predicted thermal flux as a function of distance for a 914 mm (36 inch) natural gas pipeline operating at a pressure of 6 200 kPa (900 psi) [80]. The gas supply is assumed to have been shut off immediately after the rupture and the released gas is assumed to have caught fire 30 seconds after rupture. Since the gas supply is shut off, the gas flow rate escaping from the pipe will decrease with time and the thermal flux will also vary with time. In this figure, each curve represents a "snapshot" in time, showing the thermal flux resulting from the fire as a function of distance from the pipeline. The curves show that the thermal flux decreases with both time and distance from the pipeline.

Figure 4.16
Thermal flux as a function of distance for a 914 mm gas pipeline operating at 6200 kPa



Source: Adapted from endnote [80]

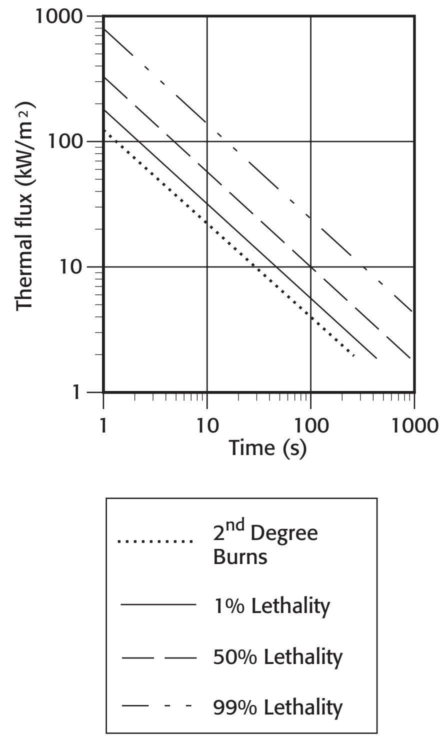
Once the thermal flux curves are determined, the effects of thermal radiation on people and structures must be predicted and analyzed. The effects of heat on people depends on the thermal flux and the duration of exposure. Figure 4.17 shows the relationship between thermal flux and exposure time corresponding to different effects on people. We can see that very high levels of intense heat will produce a high probability of fatality within a short period.

A level of thermal radiation corresponding to a particular effect is then selected as the criterion for calculating selective pipe replacement distances. For example, in 1992, for the calculation of the selective pipe replacement distances for the SCC-susceptible portions of lines 100-1 and 100-2, TransCanada used piloted wood ignition as the criterion for determining a safe distance from the fire [82]. The piloted wood ignition criterion is the intensity of thermal radiation that is required to ignite wood, assuming that a small pilot flame is near its surface.

CEPA indicated that its member companies have not yet reached a consensus on the appropriate distance criterion for selective pipe replacements [83].

CEPA further indicated that one of the disadvantages of selective pipe replacements is *"…the lack of availability of accurate consequence models, which may vary according to the service fluids."* [84] Since the proximity replacement distances are determined by modelling the hazards associated with pipeline ruptures and their effects on people, property and environment, it is essential that pipeline operators have access to a variety of accurate models.

Figure 4.17
Effects of thermal flux and exposure time on people



For example fluxes over 60 kW/m² are associated with a 50 per cent lethality level in 10 seconds or less of exposure.

Source: Adapted from endnote [81]

4.7.3 Conclusions

Selective pipe replacement is an effective means of preventing service failures due to SCC in the replacement section. Provided the replacement distances are properly established, selective pipe replacements are highly effective in minimizing the consequences of service failures on people, property and environment. As previously discussed, the most important factor in the prevention of SCC in the replacement pipe is the application of an effective coating.

It is important that reliable and accurate hazard and consequence models for different service fluids be developed, verified and made available. In the absence of such models, empirical field data from previous failures should be used.

We consider it important that the pipeline industry agree on the appropriate criteria for determining safe distances from the effects of a pipeline failure.

Recommendation

4-8 We **recommend** that the Board request that CEPA:

a) continue the development and verification of models that predict the hazards and consequences associated with pipeline failures for different service fluids; and

b) develop criteria for determining safe distances from the effects of pipeline failures.

Chapter Five

Community Issues

5.0 Introduction

The previous chapters have focused on the very technical aspects of SCC: what it is, the tools we currently use to deal with it and the tools that may be available in the future. This chapter is intended to provide a different perspective: the point of view of the people who live and work near pipelines.

We received reports from four public consultations with communities along the TransCanada system and from a meeting with the Ontario Pipeline Landowners Association (OPLA) held in the fall of 1995. The reports gave details of the discussions at the meetings.

The issues raised by the communities and by OPLA that were relevant to the Inquiry fell into three general areas:

- design requirements for pipelines,
- emergency preparedness and response activities, and
- communications between the communities and the pipeline companies and between communities and the National Energy Board.

In addition, some local residents raised a number of concerns about subjects such as intervenor funding and land use compensation that this Inquiry could not deal with because these topics were outside of its mandate. However, we are aware that these concerns are being considered in other forums.

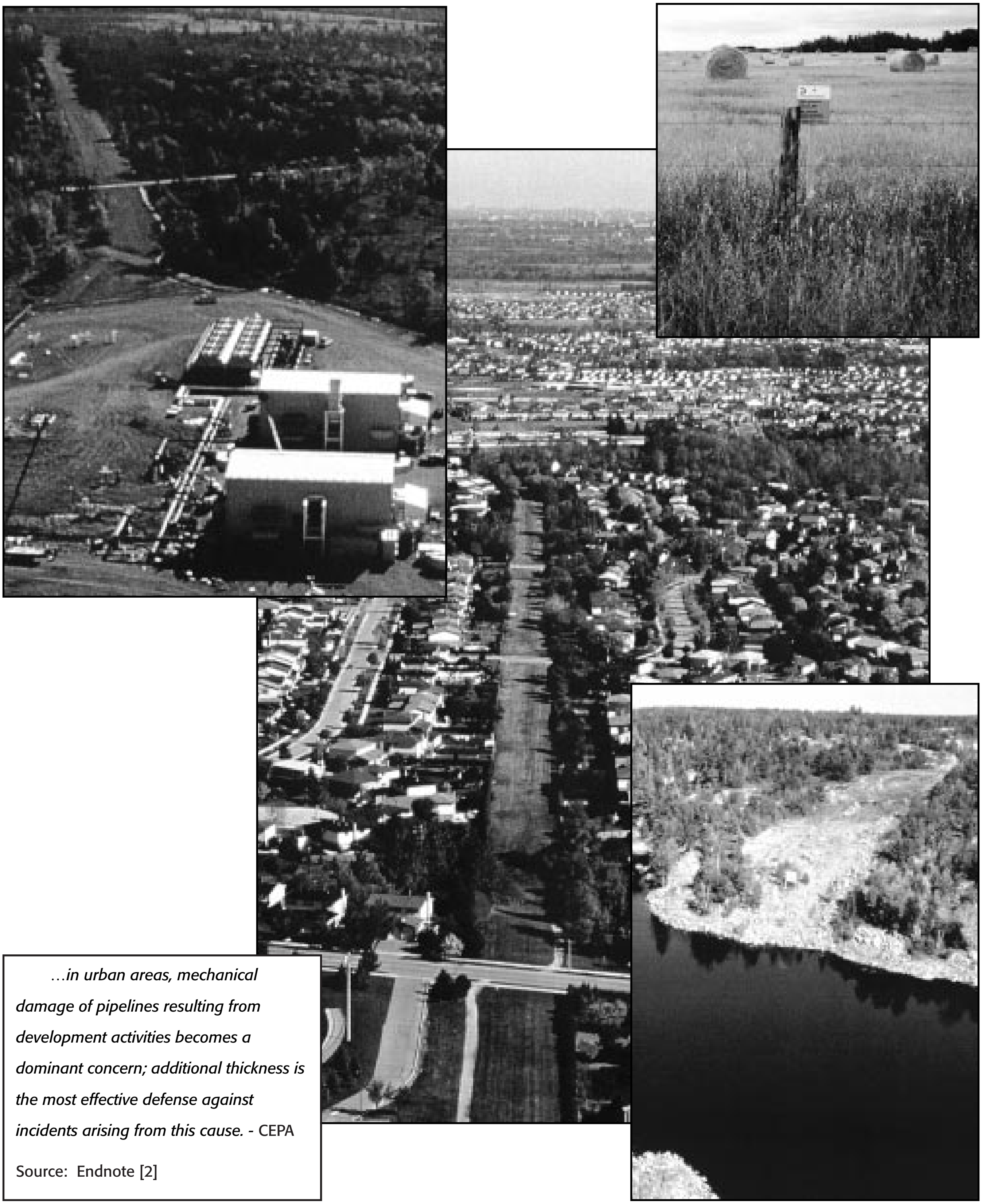
5.1 Design requirements for pipelines

Two pipeline design issues of particular concern to communities were raised at the Inquiry: the minimum wall thickness of pipelines in rural areas, and separation distances or buffer zones between pipelines and the buildings and houses nearby.

5.1.1 Pipe wall thickness requirements

OPLA [1], as well as individual landowners in rural areas, noted that pipelines located in rural areas could be operated at higher stress levels than those in urban areas and, consequently, the pipelines in rural areas did not have to be as thick. The difference in wall thickness requirements was considered a safety concern in that the regulations that govern pipelines do not give people in rural areas the same protection as people living in urban areas.

Figure 5.1
Urban and rural pipeline rights-of-way



Photos Courtesy of TCPL

…in urban areas, mechanical damage of pipelines resulting from development activities becomes a dominant concern; additional thickness is the most effective defense against incidents arising from this cause. - CEPA

Source: Endnote [2]

As discussed in Chapter 3 (Table 3.2), the CSA Z662 standard, which has been incorporated into the Board's pipeline regulations, sets the maximum allowable stress level of a pipeline. These levels are based on the class location of a pipeline, which is generally a measure of the population density in the immediate vicinity of the pipeline. As the population density increases, the maximum allowable stress level of the pipeline is reduced.

In order to lower the stress on a pipeline, a company may lower the operating pressure, use higher strength pipe or use thicker wall pipe. The company will generally choose the latter.

The requirement for lower operating stresses in areas where there are more people is a common approach in pipeline standards in the U.S., Europe and elsewhere around the world. However, limitations on operating stresses represent just one of many safety provisions in the CSA standard. The standard sets out minimum requirements for the design, material selection, construction, pressure testing and operating and maintenance practices. All of these factors need to be taken into account when assessing the safety of a pipeline.

In addition to meeting (and often exceeding) the minimum requirements of the CSA standard, pipeline companies generally implement maintenance practices that further enhance the long-term integrity of their systems. As pipelines age, it becomes increasingly important that companies ensure the safety of their facilities. The SCC management program discussed in Chapter 6 is intended to maintain the long-term integrity of pipelines affected by SCC. That program is designed to prioritize monitoring and mitigative activities on the basis of susceptibility to "significant" SCC. Consequently, pipes in Class 1 locations would be expected to have a higher priority for monitoring and mitigation than thicker wall pipe.

5.1.2 Buffer zones

People at the community meetings raised a second concern relating to pipeline design requirements. They questioned whether there should be a separation distance, or buffer zone, between pipelines and nearby buildings and houses. No such requirement is currently in place in the CSA Z662 standard, nor in the Board's Onshore Pipeline Regulations.

Creating a buffer zone would be an effective way of reducing the risk associated with a gas pipeline failure because there is less danger farther away from a failure. One method of creating a buffer zone is to put restrictions on how the land near the pipeline may be used. For example, land use close to a pipeline may be limited to low-density industrial use or parkland. But residential housing, shopping centres and other high-exposure areas would not be allowed within a certain distance from the pipeline. How far that would actually be would depend on the likely consequences of a pipeline failure. For example,

> *In general, pipeline companies do not own their rights-of-way. They simply have the right to build the pipeline and to operate it and to maintain it.*
>
> *The acquisition of the land for an effective buffer zone, together with the need to, if you will, sterilize it for all time, would be, I suggest, quite impracticable in the current environment.* - B. Rothwell, CEPA
>
> Source: Endnote [3]

the consequences might depend, at least partly, on the size of the pipe and its operating pressure. The size of the buffer zone for a gas pipeline would be determined by looking at such factors.

In its submission [4], CEPA stated:

> *...it is not considered that the general adoption of wider buffer zones would offer a viable means of minimizing the consequences of operational failures resulting from SCC. The establishment of buffer zones for new pipelines would, in all probability, make land acquisition impracticable. The retroactive imposition of buffer zones to existing pipelines would require major re-zoning initiatives, including the removal of existing buildings, or pipeline re-routing.*

A task force is currently working on developing guidelines for land use planning near pipelines. The membership of the Major Industrial Accidents Council of Canada (MIACC) Pipeline Task Force is made up of municipal planners, academics and representatives from pipeline companies and regulatory agencies, including the NEB and the Alberta Energy and Utilities Board (AEUB). The principal objectives of the guidelines are to raise the awareness regarding the issue of land use around pipelines and to facilitate communication and negotiation between pipeline companies and communities on a case-by-case basis.

5.1.3 Conclusions

Pipe wall thickness. We believe that the recommendation we make in Chapter 6 requiring that pipeline companies have a comprehensive SCC management program will ensure that companies continually review their pipeline systems and satisfy themselves, the regulatory authorities and the public that SCC is being effectively addressed on their systems.

The safety of a pipeline depends on many factors, including pipeline design, material selection, testing, construction practices and operating and maintenance practices. The safety of a pipeline cannot be measured on the basis of a single factor such as operating stress or wall thickness.

If our recommendation that pipeline companies be required to have a comprehensive SCC management program is adopted, we do not believe that changes to the CSA standards in respect of limitations on operating stresses or wall thickness requirements will be necessary.

Buffer zones. Based on the information examined during the Inquiry, we conclude that the application of buffer zones for all pipelines would not be practicable, especially if applied retroactively to existing pipelines. While we are not recommending the general application of buffer zones as a means of addressing the SCC problem, we believe that buffer zones can be effectively used in many cases to improve public safety.

Emergency Procedures

The following requirements are specified in the Board's Onshore Pipeline Regulations:

49.(1) The emergency procedures referred to in paragraph 48(1)(l) shall include

(a) a statement of the scope of application of the emergency procedures;

(b) a detailed description of the facilities to which the emergency procedures apply, including

(i) the location of and means of access to the facilities, and

(ii) the number and size of the pipelines involved;

(c) a description of the pressure, flow rate and other normal operating conditions of the pipeline;

(d) the procedures for the documentation of emergencies;

(e) the instructions and warnings to be given to persons reporting an emergency;

(f) the initial action to be taken on discovery of an emergency;

(g) the names and telephone numbers of company personnel or departments to be contacted in the case of an emergency and the respective responsibilities of the personnel or departments;

(h) the names and telephone numbers of public services and other agencies that might have to be contacted in the case of an emergency;

(Continued on page 97)

We believe that the issue of land use around pipelines would be best resolved through improved communication and negotiation between pipeline companies and communities on a case-by-case basis.

5.2 Emergency preparedness and response

The results of the Inquiry's community consultations showed, in general, that individual residents, local emergency responders and communities felt that they could be better informed and better trained to deal with emergencies. People expected pipeline companies to play a significant role in preparing communities for an emergency.

In this regard, the Board's Onshore Pipeline Regulations require pipeline companies to develop emergency procedures for their pipeline systems and to update them regularly, in consultation with local police, fire departments and other response agencies. All company employees who may be involved in an emergency response are required by the Regulations to receive appropriate training.

However, in many cases, local residents are the first people at the scene of a pipeline failure. Local emergency responders like the police or fire departments usually arrive next. They provide site control until pipeline company personnel arrive and, if necessary, assist in evacuations or rescues. Generally, pipeline companies have programs in place to familiarize local emergency responders with the pipeline and the commodity it carries. They also promote a coordinated response to emergencies. But beyond this familiarization, local emergency responders typically receive no other formal training from the pipeline companies. Emergency responders are expected to take it upon themselves to be prepared to respond. It is important to note that in most of the communities along pipeline rights-of-way, fire departments consist of volunteers.

The consequences of a failure are aggravated if information to the landowners and individual residents and training for the responders are inadequate. In Williamstown, for example, the TransCanada pipe ruptured and released a large amount of gas, although the gas did not ignite. Some emergency responders and landowners were uncertain about what the proper emergency procedures were for that situation. During the community consultations, responders said they were unsure if they would know what to do if a similar event happened again. Not all responders knew whether people should be evacuated, whether the electricity should be shut off, whether telephones could be safely used or what distance from the pipeline would be considered safe. Many residents living near the pipeline were also uncertain about the proper procedures to follow.

In general, residents, emergency response agencies and community officials all wanted additional information, training and emergency response coordination with the pipeline company. Even in

(i) the plans for co-operation with appropriate public agencies during an emergency;

(j) a description of the types and locations of available emergency equipment and, in the case of HVP pipelines, a description of the types and locations of portable emergency shut-off devices;

(k) the procedures to be followed at the site of the emergency;

(l) the safety precautions to be taken during an emergency, including

(i) the handling of the fluid transported by the pipeline,

(ii) the isolation and shut-off procedures for stations of the pipeline, and

(iii) the methods for monitoring the hazard level at the site;

(m) a list of the environmentally sensitive areas that would require special attention during an emergency;

(n) contingency plans for the immediate protection of the environment; and

(o) evacuation procedures.

49.(2) A company that operates a pipeline shall update the pipeline's operating and maintenance manuals in respect of the plans and procedures referred to in paragraphs (1)(i) and (1)(o) on a regular basis in conjunction with the appropriate authorities.

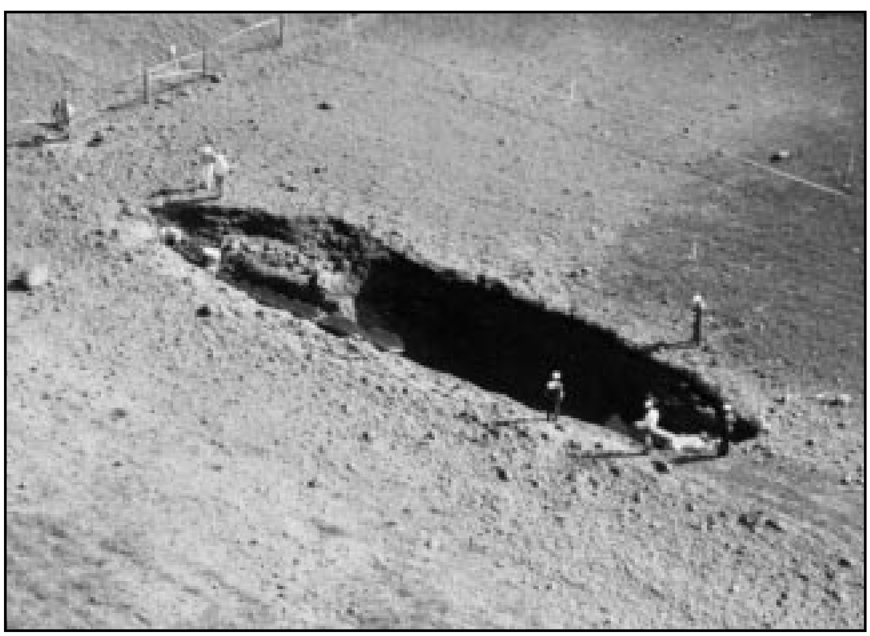
the Rapid City and Vermilion Bay communities, where people were generally satisfied with the response by the local emergency responders and TransCanada, many of those surveyed said they needed more training and information.

TransCanada stated during the Inquiry that it had implemented changes to its emergency response policies and practices [5]. The company has developed a brochure that provides basic information to residents living along the right-of-way on what to do in the case of a pipeline emergency on the TransCanada system.

TransCanada contacts local emergency response agencies more frequently than it used to. Instead of visiting these groups once every four years, the company now makes annual visits. The company has also developed a brochure for first responders that outlines the latter's responsibilities during a pipeline emergency. In addition, the company is developing a training video to be distributed to any first response agency that may have to respond to an emergency on the TransCanada system. For the communities themselves, TransCanada will be ensuring that public officials are informed of the presence of pipeline facilities within their communities, the hazards those facilities pose, the possible consequences of a failure and the need for coordinated planning with emergency responders.

In another initiative, TransCanada and the Regional Municipality of Hamilton-Wentworth in Ontario are working together to create a planning framework that individual communities could use to develop their own emergency response plans. The resulting framework was to be completed in mid-1996 and will be used to develop similar coordinated response plans in each of the approximately 320

Figure 5.2
Pipeline failure site: Williamstown, Ontario, October 1994



municipalities in which TransCanada has facilities. The project will improve the coordination of TransCanada's emergency response efforts with those of large emergency response organizations.

TransCanada's work in this area may be valuable to other pipeline companies facing similar issues.

5.2.1 Conclusions

We believe that pipeline companies must have effective procedures and policies in place that address emergency preparedness and response for their systems. Such procedures and policies should address the preparedness and involvement of residents, the local communities and the emergency responders along the pipeline system. These groups must be fully informed and it is the company's responsibility to provide the appropriate information.

Recommendation

5-1 We recommend that, as part of its ongoing monitoring activities, the Board review companies' emergency response practices to ensure that adequate training is provided to first responder organizations and that appropriate information is provided to the communities on the proper procedures to follow in the event of pipeline emergencies.

5.3 Communications

Following failures on its system, TransCanada has sometimes held open house sessions in the affected communities. The Inquiry's consultations and discussions revealed people's discontent with the format of those sessions. People suggested that a formal presentation by the company, followed by an open question-and-answer period, would be more effective than the one-on-one discussion format that TransCanada normally used. They wanted to hear what their neighbours had experienced and know that all residents were getting the same message. Responses from all of the communities showed that open houses or similar community meetings held after pipeline failures should provide an open question-and-answer period.

Also, many people felt that their questions had not been adequately answered by the company. For example, a year after the failure in the Williamstown area, some people still had not received answers to their questions about the cause of the accident and what they should do to protect themselves in the event of another accident.

At the hearing, TransCanada acknowledged people's concerns about its open house sessions and undertook to improve its public awareness and emergency preparedness programs. In its Closing

> *Pipeline landowners have been held in isolation from each other in many cases in the past. The open house approach has been frustrating in most instances for landowners because individual landowners usually do not have sufficient knowledge to ask significant questions. However, by having landowners together at a specific time and place, landowners automatically pool their knowledge and concerns.* - OPLA
>
> Source: Endnote [7]

Statement to the Inquiry [6], TransCanada made the following commitments:

> *TransCanada is currently reviewing its public awareness and first responder programs and will enhance them;*
>
> *A landowner/tenant survey and community interest groups will be utilized to obtain feedback from the public on improvements to individual emergency response information and guidance and modes of communication to enhance both;*
>
> *Open House formats will be reviewed and enhanced based on discussions with community officials; and*
>
> *TransCanada will participate in post inquiry community meetings at various locations along the pipeline system.*

In addition to the desire for increased communication with pipeline companies, the communities surveyed also expressed the need for the Board to take a higher profile and to include community issues as part of its accident investigation program.

5.3.1 Conclusions

We consider the Inquiry to have focused needed attention on this critical area of post-accident communication. We believe that this is an area where the Board should take a more active role.

Recommendation

5-2 We **recommend** that the Board expand the scope of its accident investigation program to include community relations and emergency response related issues.

Chapter Six

Looking Forward

6.0 Introduction

In this chapter we discuss what we have learned about the extent of SCC in Canada and what companies are currently doing about managing the SCC problem. Then we move forward to discuss what steps should be taken to address the SCC problem, both on a company by company basis and as industry-wide initiatives.

6.1 Experience with SCC

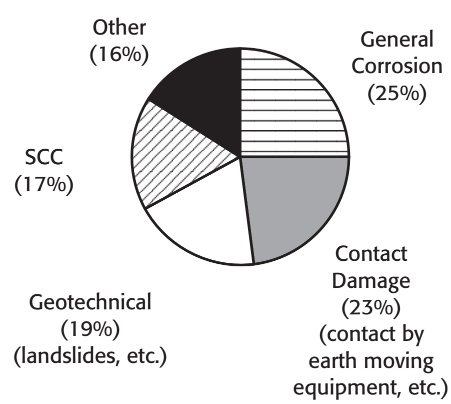
Since 1977, near-neutral pH SCC has caused 22 pipeline failures in Canada. SCC is not solely a concern in Canada, as there have been many more failures around the world. The United States has experienced more failures than Canada, although most of these were caused by high pH SCC and occurred over a longer period of time. INGAA reported that the frequency of SCC failures in the U.S. has markedly declined over the past few decades [1]. Outside of North America, the former Soviet Union has a failure history with near-neutral pH SCC similar to that in Canada and pipeline systems in Australia, Iran, Iraq, Italy, Pakistan, and Saudi Arabia have also been affected by SCC [2].

Although SCC in Canada has resulted in pipeline failures, SCC is only one potential threat to pipeline integrity and public safety. As Figure 6.1 illustrates, SCC accounted for 17 per cent of the 48 in-service ruptures experienced by CEPA member companies between 1985 and 1995. CEPA indicated that when pipeline leaks are included in the statistics, SCC caused an even smaller percentage of pipeline failures. General corrosion, contact damage and geotechnical damage all caused more ruptures than SCC. However, the pipeline industry has been dealing with these other causes for a much longer period of time than it has been with SCC. Experience has provided a better understanding of how to reduce the risk of failure from other causes, whereas SCC has yet to be fully understood by the pipeline industry and the research community. Because of this, SCC remains a serious concern to the pipeline industry in Canada.

6.1.1 The extent of SCC in Canada

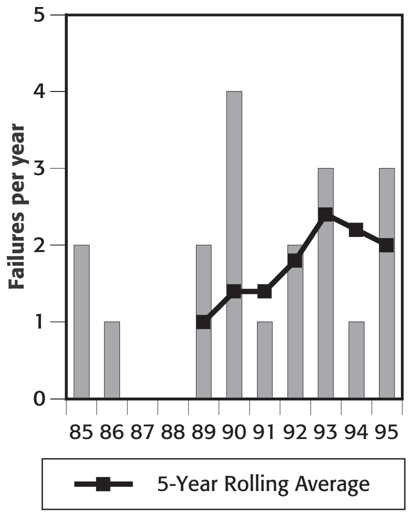
The evidence indicated that, of the 11 CEPA member companies which have undertaken investigative programs, eight have found SCC on their systems. The majority of the SCC found has been

Figure 6.1
Causes of service ruptures experienced by CEPA member companies: 1985-1995



Source: Endnote [3]

Figure 6.2
Distribution of SCC failures



"insignificant". A few companies have developed an estimate of how much of their system is susceptible. For example, through the use of a detailed predictive model and an extensive excavation program, TransCanada estimates that 3.6 per cent of its system is potentially susceptible to "significant" SCC [4].

6.1.2 Failure history in Canada

The 22 pipeline failures caused by SCC in Canada include 12 ruptures and 10 leaks on both natural gas and liquids pipeline systems [5]. In particular, eight of the 22 failures occurred on the TransCanada system between 1985 and 1995. Seven of these failures were ruptures. NOVA and Northwestern Utilities Limited each had three failures. In all, ten different companies have experienced SCC failures. A summary of the 22 failures is provided in Table 6.1. The geographic locations of the failures are shown in Figures 6.4 and 6.5 for both gas and liquids pipeline systems.

There does not seem to be a clear pattern in the number of SCC failures over the past ten years. As Figure 6.2 shows, the occurrence of SCC failures reached a high of four failures in 1990. However, a five-year rolling historical average shows an increase from 1989 to 1995 from an average of under one failure per year to two failures per year.

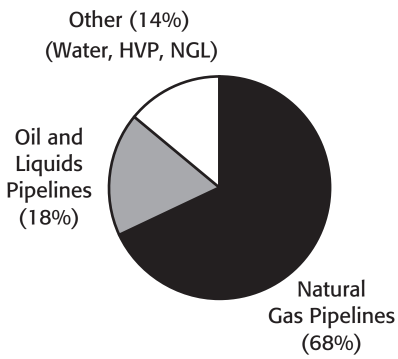
Table 6.1
History of SCC failures in Canada

Year of Failure	Company	Type of Failure	Product Released	Pipe Diameter mm (inches)	Type of Coating	Year of Installation	Cause of Failure	Operating Stress Level (as % SMYS)
1977	NOVA Gas Transmission Ltd.	Leak	Natural Gas	914 (36)	Polyethylene tape	1969	Circumferential SCC due to axial loading	63%
1979	Rimbey Pipe Line Co. Ltd.	Leak	HVP (propane)	219 (8)	Coal tar epoxy	1961	SCC associated with multiple severe gouges	58%
1985	TransCanada PipeLines Ltd.	Rupture	Natural Gas	914 (36)	Asphalt	1972	SCC associated with minor scratches/ gouges	71%
1985	TransCanada PipeLines Ltd.	Rupture	Natural Gas	914 (36)	Polyethylene tape	1972	SCC at toe of DSAW long seam weld	76%
1986	TransCanada PipeLines Ltd.	Rupture	Natural Gas	914 (36)	Polyethylene tape	1973	SCC at toe of DSAW long seam weld	70%
1989	TransCanada PipeLines Ltd.	Leak	Natural Gas	914 (36)	Asphalt	1968	SCC on pipe body under mastic repair	71%
1989	Northwestern Utilities Ltd.	Leak	Natural Gas	219 (8)	Polyethylene tape	1970	Circumferential SCC	58%

Year of Failure	Company	Type of Failure	Product Released	Pipe Diameter mm (inches)	Type of Coating	Year of Installation	Cause of Failure	Operating Stress Level (as % SMYS)
1990	NOVA Gas Transmission Ltd.	Leak	Natural Gas	168 (6)	Polyethylene tape	1969	Circumferential SCC due to axial loading	53%
1990	Northwestern Utilities Ltd.	Leak	Natural Gas	291 (8)	Polyethylene tape	1970	Circumferential SCC	53%
1990	Northwestern Utilities Ltd.	Leak	Natural Gas	219 (8)	Polyethylene tape	1970	Circumferential SCC	53%
1990	Amoco Canada Petroleum Company Ltd.	Leak	Crude Oil	101 (4)	Polyethylene tape	1965	SCC in ERW long seam weld	46%
1991	TransCanada PipeLines Ltd.	Rupture	Natural Gas	508 (20)	Coal tar	1957	SCC in ERW long seam weld	71%
1992	TransCanada PipeLines Ltd.	Rupture	Natural Gas	914 (36)	Polyethylene tape	1972	SCC at toe of DSAW long seam weld	77%
1992	Imperial Oil	Leak	Water	101 (4)	Foamed glass insulation	1988	SCC/general corrosion on water injection riser	50%
1993	Rainbow Pipe Lines Co. Ltd.	Rupture	Crude Oil	610 (24)	Polyethylene tape	1968	SCC associated with linear general corrosion	61%
1993	Rainbow Pipe Lines Co. Ltd.	Rupture	Crude Oil	610 (24)	Polyethylene tape	1968	SCC associated with linear general corrosion	72%
1993	Federated Pipe Lines Ltd.	Leak	NGL	406 (16)	Shrink sleeve over yellow jacket	1970	Circumferential SCC	67%
1994	NOVA Gas Transmission Ltd.	Rupture	Natural Gas	219 (8)	Polyethylene tape	1970	SCC associated with linear corrosion	60%
1995	TransCanada PipeLines Ltd.	Rupture	Natural Gas	914 (36)	Polyethylene tape	1972	SCC at toe of DSAW long seam weld	74%
1995	TransCanada PipeLines Ltd.	Rupture	Natural Gas	1067 (42)	Polyethylene tape	1968	SCC at toe of DSAW long seam weld	77%
1995	Pacific Northern Gas Ltd.	Rupture	Natural Gas	273 (10)	Polyethylene tape	1968-69	SCC associated with general corrosion	71%
1996	Interprovincial Pipe Line Inc.	Rupture	Crude Oil	864 (34)	Polyethylene tape	1968	SCC associated with linear corrosion	70%

Source: Endnote [5]

Figure 6.3
SCC failures: by type of pipeline



Sixty-eight per cent of the SCC failures occurred on natural gas transmission pipelines (Figure 6.3). However, the evidence provided at the Inquiry does not give a clear understanding as to why more gas pipelines than liquids pipelines have been affected by near-neutral pH SCC. Contributing factors may include the greater length of gas pipelines operating at higher stress levels and the greater length of gas transmission pipelines that were installed when polyethylene tape coated pipe was commonly used (Figure 1.3). For example, among CEPA member companies, the total length of polyethylene tape coated pipe in gas pipeline systems is four times that in liquids pipeline systems [6].

The Inquiry reviewed the 22 failures and looked for correlations between the incidence of SCC and type of coating, pipeline age, manufacturing process and operating stress level. These correlations have been discussed in detail in Chapter 3. In summary, most of the failures occurred on pipelines that were coated with polyethylene tape and installed between 1968 and 1973. The operating hoop stresses associated with the 22 failures varied between 46 and 77 per cent of the pipe's SMYS. In almost all cases, however, there were external factors such as external corrosion and minor gouges which increased the stress levels at the failure area. With one exception, no correlation was found

Figure 6.4
Location of SCC failures on natural gas pipelines

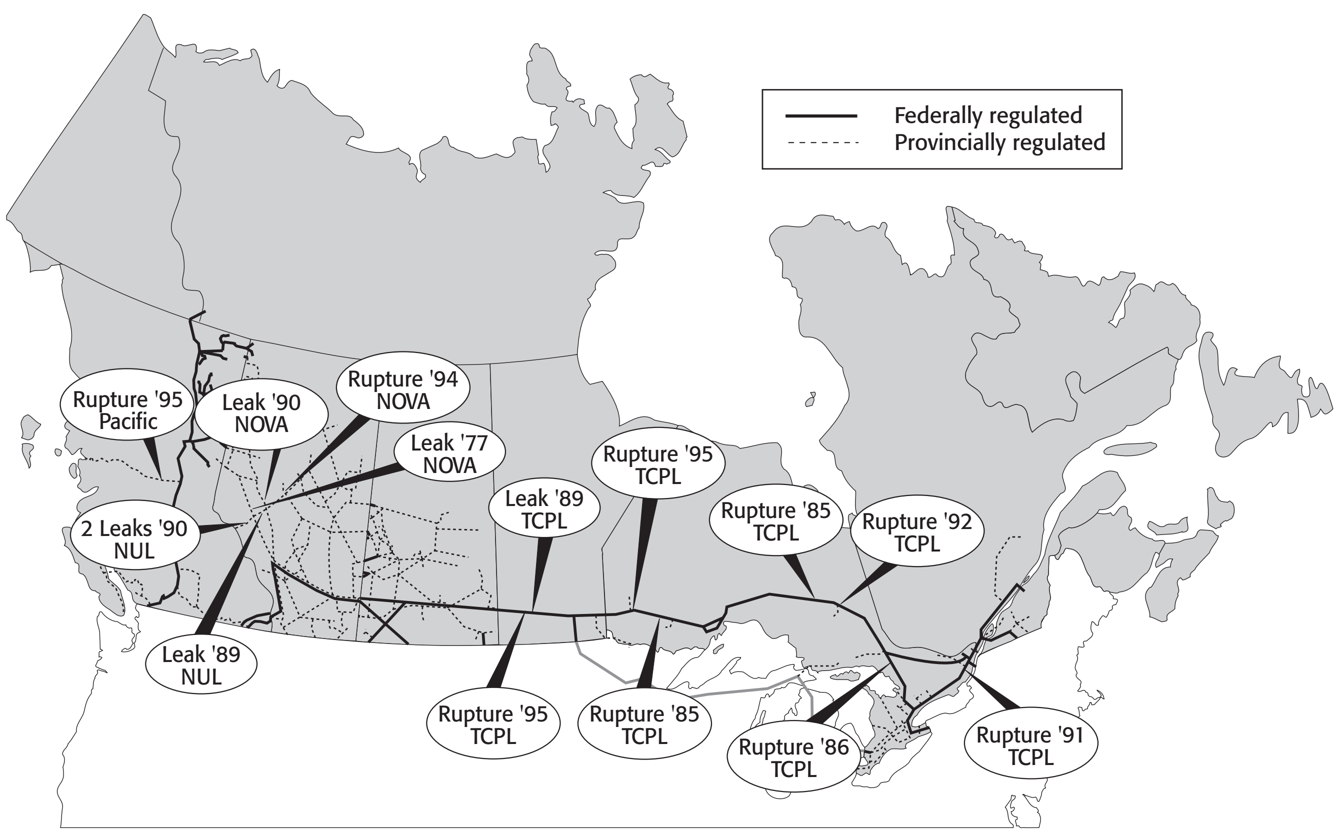
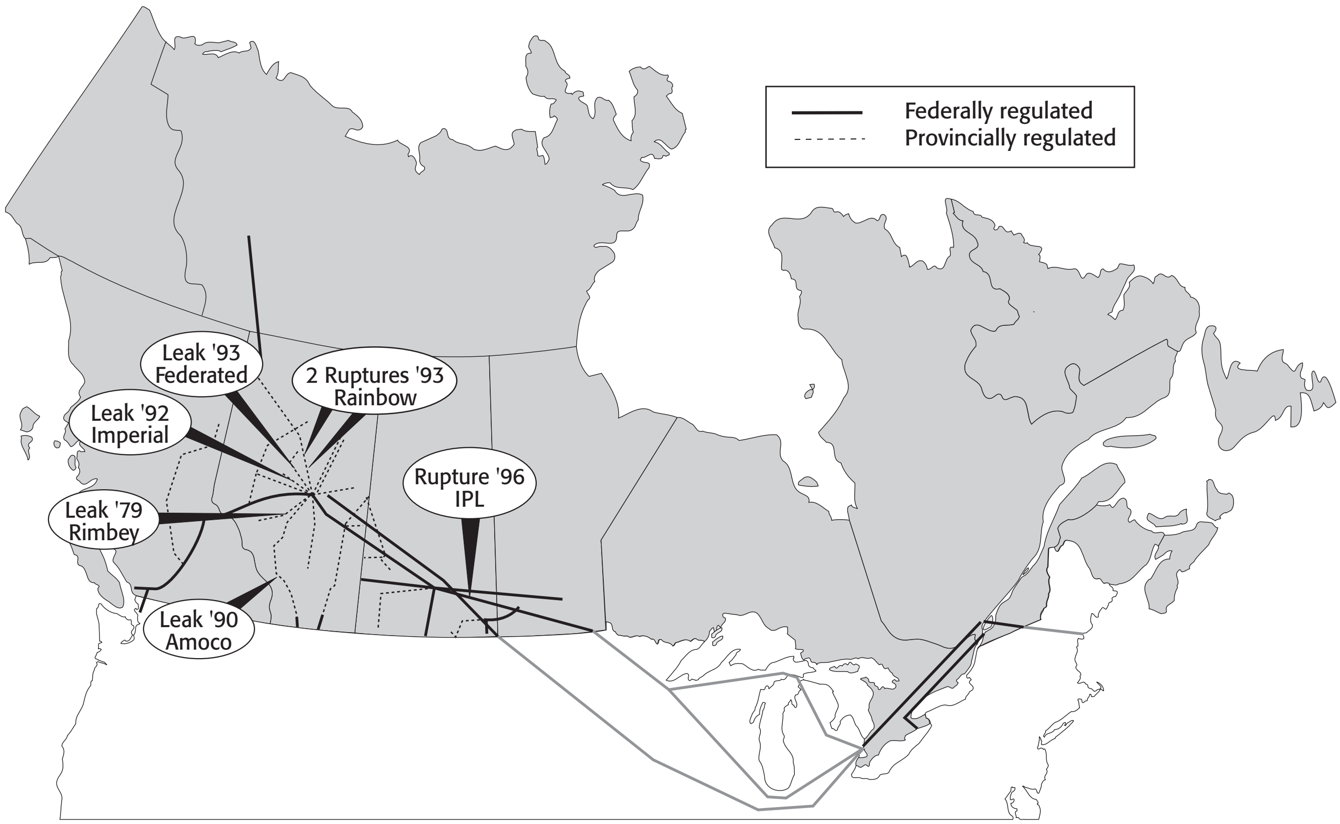


Figure 6.5
Location of SCC failures on liquids pipelines



between near-neutral pH SCC and pipe grade, pipe manufacturer or manufacturing process. The exception was Youngstown pipe on a portion of the TransCanada system.

6.1.3 Costs associated with failures

The direct costs associated with a pipeline failure include the cost of pipeline repair, property restoration and product lost during the incident. Evidence submitted to the Inquiry indicated that the average direct cost of a rupture on a large diameter natural gas pipeline is approximately $1.5 million; for a leak, the average direct cost is estimated at $150 000 [7]. Indirect costs are harder to quantify. These may include the impacts on the affected communities, loss of system throughput, potential loss of market share by shippers and addressing concerns over the reliability of the pipeline system.

6.1.4 Conclusions

In the first public Inquiry into SCC in 1993, the Board concluded that SCC was not a widespread problem on Canadian pipeline systems. Since that time, however, there have been eight additional failures due to SCC in Canada, three of which occurred on Board regulated pipelines.

Four companies have experienced their first SCC related failures. Also since the first Inquiry, SCC has caused more failures on liquids pipelines as well as gas pipelines and a number of companies have detected SCC on their systems for the first time.

Since SCC develops over time, it is a problem that can only become more serious if no action is taken to deal with it.

Based on the evidence presented in the Inquiry, we believe that SCC remains a serious concern for the pipeline industry. Without proper attention, it will inevitably be the cause of more pipeline failures. However, the pipeline industry is aggressively addressing the situation.

6.2 SCC management programs: current practices

We learned what companies are doing to deal with the problem of SCC on their systems. CEPA described its members' current situation as falling into one of three categories:

- companies that have not found any SCC on their systems (some of these companies have looked for SCC while others were planning to make initial assessments of their systems);
- companies that have found some SCC on their systems and have begun to monitor it; and
- companies that have implemented SCC mitigation programs on portions of their systems.

Table 6.2 summarizes what CEPA member companies are doing about SCC. However, the evidence presented at the Inquiry indicates that companies do not take a standardized approach in the management of SCC.

CEPA reported that four companies are conducting, or have plans to conduct, initial assessments of the SCC on their systems. These companies have not experienced an SCC related failure and have not found any SCC on any part of their systems.

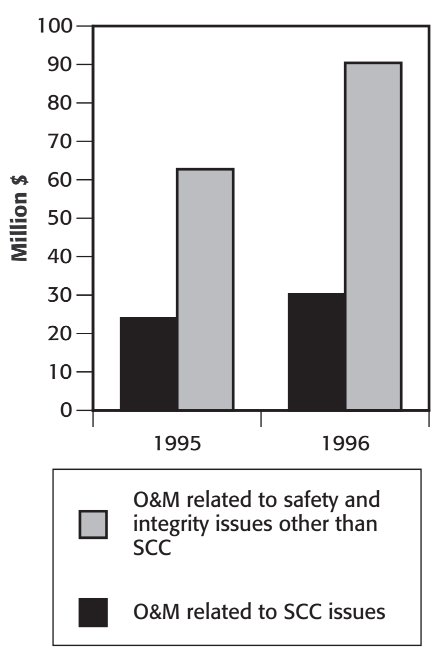
Seven companies have found some "insignificant" SCC on portions of their systems. Although the extent of the SCC monitoring program differs from company to company, these companies generally apply the same monitoring, assessment and inspection techniques as those companies that have not found SCC.

Two CEPA member companies, NOVA and TransCanada, have had ruptures on their systems and have implemented SCC mitigation programs. TransCanada's program includes hydrostatic retesting of sections of the pipeline and replacement of pipe where there is a possible risk to people living near the right-of-way. NOVA has also conducted hydrostatic retests on portions of its pipeline affected by SCC.

In the spring of 1996, IPL experienced a pipeline failure that was caused by SCC associated with general corrosion [8].

In Figure 6.6, we present the costs of CEPA member companies' operation and maintenance (O&M) activities related to SCC versus

Figure 6.6
CEPA member companies: O&M expenditures on pipeline integrity



Source: Endnote [9]

Table 6.2
Current SCC management practices of CEPA member companies

Company	System Length km (miles)	SCC Failure Experience	Predictive Model Developed	Investigative Excavations Conducted	SCC Found (Severity)	Hydro-static Retests	Proximity Replace-ments	In-Line Inspection Capability (% of System)
Alberta Energy Company Ltd.	1 100 (660)	No	No	Yes	Significant	No	No	100
Alberta Natural Gas Company Ltd	177 (106)	No	Yes	Yes	Insignificant	No	No	99
Canadian Western Natural Gas Company Ltd.	2 560 (1,536)	No	Developing	No	N/A	No	No	0
Foothills Pipe Lines Ltd.	927 (556)	No	Yes	Yes	Insignificant	No	No	83
Interprovincial Pipe Line Inc.	8 197 (4,918)	Yes	Developing	Yes	Insignificant	Yes	No	90
Northwestern Utilities Limited	3 839 (2,303)	Yes	Developing	Yes	No	Yes	No	1
NOVA Gas Transmission Ltd.	20 271 (12,162)	Yes	Yes	Yes	Insignificant	Yes	Yes	14
TransCanada PipeLines	14 000 (8,400)	Yes	Yes	Yes	Significant	Yes	Yes	17
TransGas Limited	13 160 (7,896)	No	Developing	Yes	No	Yes	No	0
Trans Mountain Pipe Line Company Ltd.	1 309 (785)	No	Yes	Yes	Insignificant	No	No	100
Trans - Northern Pipelines Inc.	876 (525)	No	No	Yes	No	No	No	100
Trans Québec and Maritimes Pipeline Inc.	339 (203)	No	Developing	No	N/A	No	No	90
Westcoast Energy Inc.	5 158 (3,094)	No	Yes	Yes	Significant	Yes	Yes	95

activities related to other safety and integrity issues. Such issues may be associated with corrosion monitoring, surveys, repairs and upgrades, staff training and public awareness campaigns.

For 1995 and 1996, SCC related activities account respectively for 28 per cent and 25 per cent of O&M costs of the total safety and integrity issues dealt with by CEPA member companies.

6.3 Standardized approach to SCC management

CEPA suggested that standard approaches to SCC management by all companies would facilitate the sharing of experiences and knowledge among companies. CEPA has developed a framework, as illustrated in Figure 6.7, for a common basic SCC management program [10]. The SCC program has not been developed in more detail beyond this basic framework. Every member company has committed to following this program, although some companies may decide to enhance the basic process.

The CEPA SCC management program starts by requiring companies to make an initial assessment to determine whether portions of their systems are susceptible to SCC. If any section is thought to be susceptible, the company would then be required to perform field investigations to look for SCC. These investigations could be done either in conjunction with other maintenance activities, or as part of a program to excavate sites similar to others where SCC had been found.

If SCC is found but not considered "significant", the company would continue to monitor the section of pipe from time to time. The period of the reassessment would be based upon the estimated crack growth rate on the section.

In the event that "significant" SCC is detected, the company would estimate the consequences of an SCC failure and, using this information, establish priorities for remedial action.

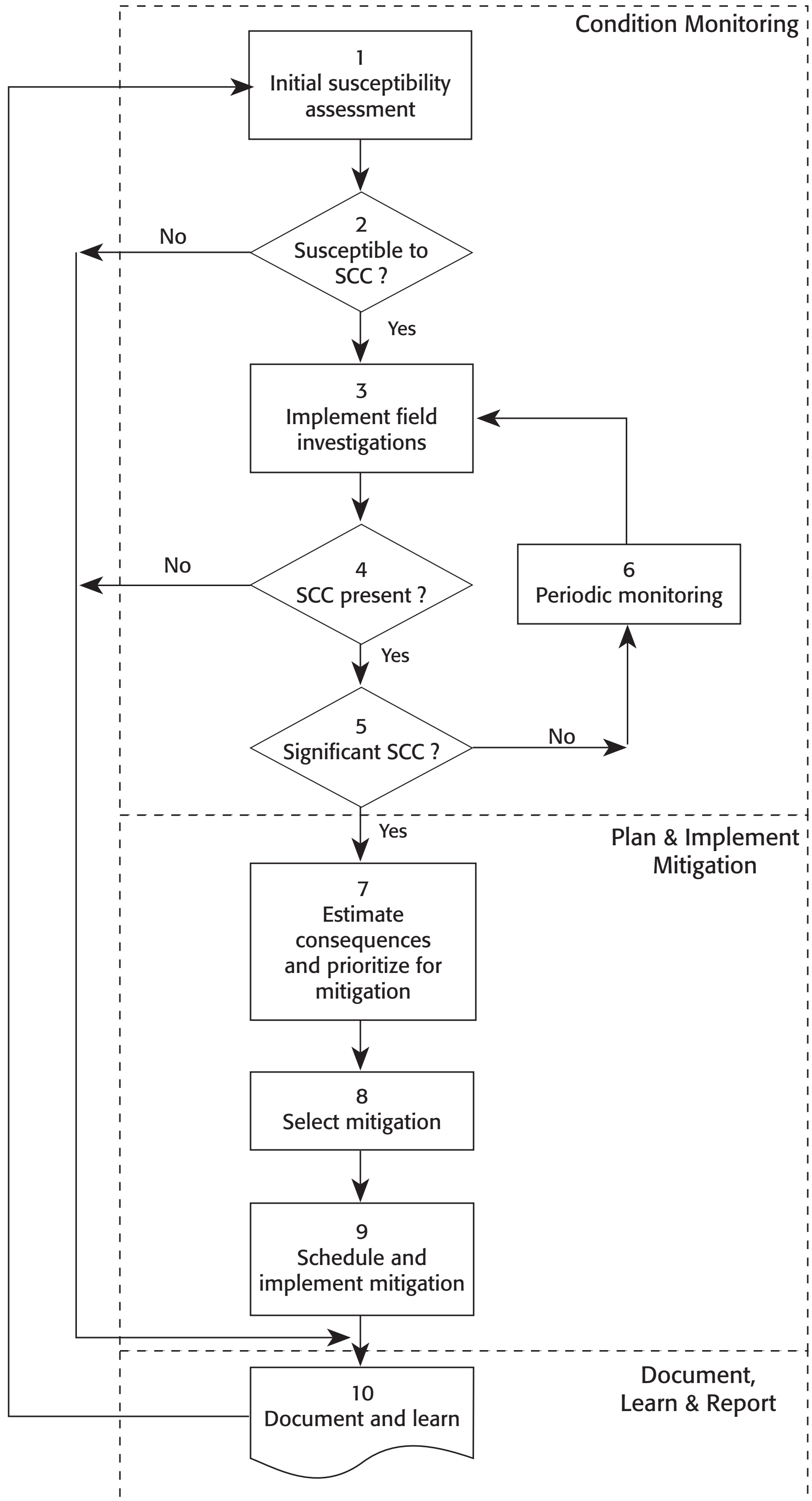
Then a mitigation method would be selected. If the SCC is not extensive, a fairly limited approach such as sleeving or selective pipe replacement might be in order. If the SCC is more extensive, a more elaborate program might be appropriate. Hydrostatic retesting might be required or, perhaps, more extensive replacement of the pipe or pipe coating. CEPA suggested that the choice would be made on the basis of how well each option provided a viable, long-term management solution to SCC with a minimum disruption to service [11].

CEPA plans to support this SCC management program with guidelines or a manual of recommended practices, specifically for longitudinal near-neutral pH SCC. The Recommended Practices Manual will reflect the current best practices of the CEPA companies that have experienced SCC. Although CEPA members have committed to following the basic SCC management program, CEPA does not intend to make the recommended practices mandatory for its members.

At the time of the hearing, the development of CEPA's recommended practices was still in the early stages and only one of several sections had been completed: the section dealing with an assessment of existing pipelines for SCC susceptibility. Other sections still to be completed will cover topics such as the design of new pipelines, SCC inspection methods, procedures and criteria for assessing SCC, data collection, and mitigation and repair techniques. This last section is scheduled for completion in March 1997. CEPA plans to update the manual periodically.

CEPA has offered to share the recommended practices with non-CEPA member companies when they are completed.

Figure 6.7
CEPA's basic SCC management program



Source: Endnote [10]

6.3.1 Conclusions

We believe that an SCC management program is essential for companies to adequately address the issue of SCC and that it should be mandatory that all NEB-regulated companies develop an SCC management program.

An SCC management program would entail the systematic application to specific pipelines of knowledge and best practices already developed across the industry. The objective of the program would be to identify areas where SCC may be found and then deal with it.

Since each pipeline system has unique physical characteristics and an individual construction and operational history, an effective program would vary from company to company. However, we believe it is necessary to establish generally applicable basic practices so that these programs will be comprehensive and consistent in approach.

We are pleased to see CEPA propose a framework for SCC management programs. This is an important initiative because the element of standardization should allow better communication among companies, regulatory authorities and the public.

The completion of the Recommended Practices Manual should be a priority for CEPA. We would expect that the recommended practices which will reflect the best practices of CEPA member companies will be of great benefit to the industry, particularly those companies operating smaller systems.

We are concerned, though, that the Recommended Practices Manual as proposed will deal only with longitudinally oriented near-neutral pH SCC. There have been pipeline failures caused by circumferential SCC and this form of SCC should be addressed in future versions of the Recommended Practices Manual.

We are of the view that the SCC management program proposed by CEPA should be strengthened and made more explicit, as follows:

- The SCC management program should identify clear lines of accountability for the implementation of the program.
- The scope of the SCC management program should encompass the company's entire pipeline system to ensure that the pipelines are thoroughly assessed.
- A company's SCC management program should be regularly updated to reflect changes in operations, new facilities, new developments near the pipeline, the lessons learned from accidents, including those on other pipeline systems, technological developments and changes to standards.
- An initial susceptibility assessment should entail a thorough examination of the pipe's design, construction and maintenance records to identify the location of coatings which are associated with SCC. If the company does not

have current or reliable information, test excavations should be conducted to verify this information.

- If, after an initial assessment, a pipeline segment is not considered susceptible, the rationale for this determination should be documented.
- If the pipeline is considered to be susceptible to SCC, the SCC management program should require active monitoring of the pipeline through an investigative excavation program. As discussed in Chapter 4, a predictive model should be used to select excavation sites. An ILI tool may be used where a pipeline company believes this will assist in detecting SCC.
- The SCC management program should describe the predictive model and detail how the excavation sites will be selected. A company should select excavation sites based upon the probability of SCC existing and the consequences of a pipeline failure. The probability of SCC existing is dependent upon the likelihood of the three necessary conditions: a potent environment at the pipe surface, susceptible pipe material and a tensile stress. As discussed in Chapter 3, particular attention should be given to pipelines operating at or above 70 per cent SMYS when selecting sites. In considering the consequences of a failure, sites close to homes, roads, and railways or sensitive environmental areas like wet lands and water crossings should be given priority over other sites that are otherwise equally likely to have SCC. We note that the pressure of a gas pipeline and an HVP pipeline will influence the affected zone in the event of a failure and accordingly the consequences of a failure.
- If "insignificant" SCC is found, the company should incorporate this information into its records, and accordingly adjust the scope and frequency of its monitoring program.
- If a company determines through its investigative excavation program, a failure investigation or by some other means, that it has "significant" SCC, the company should take mitigative action as quickly as possible. The SCC management program should detail the criteria that will be used to decide among available mitigative alternatives.
- Should a Board-regulated company determine that it has "significant" SCC on its system, this fact, as well as information on any mitigative actions taken, should be reported to the Board immediately. The company should develop and submit a comprehensive mitigation program as soon as possible.

- A company should keep records of all activities and decisions related to its program and be able to show how the information gathered from its monitoring program and from the experiences of other companies is incorporated into its SCC management program. The SCC management program should also outline how the experiences gained by the company are shared with the rest of the pipeline community.

CEPA could assist its member companies by developing guidelines for SCC management programs which reflect these features.

The recommendations that follow are intended to apply to NEB-regulated companies.

Recommendations

6-1 We **recommend** that the Board require each pipeline company to develop and implement an SCC management program by 30 June 1997.

6-2 We **recommend** that the Board require SCC management programs to identify the accountability for the implementation of the program.

6-3 We **recommend** that the Board require SCC management programs to provide for the review of the company's entire pipeline system and for regular updating.

6-4 We **recommend** that the Board require SCC management programs to consider the consequences and the probabilities of a failure when establishing priorities for investigative, mitigative and preventive activities.

6-5 We **recommend** that the Board require that SCC management programs contain three principal components:

a) determination of pipeline susceptibility to SCC and active monitoring of pipelines believed to be susceptible to SCC;

b) required mitigation, if "significant" SCC is found, and clear identification of the criteria a company must consider in deciding among mitigative options; and

c) recording and sharing of information on susceptible pipelines.

6-6 We **recommend** that the Board require companies to report immediately to the Board any finding of "significant" SCC and any immediate mitigative actions taken and to develop and submit a plan detailing the specific mitigative measures to be implemented and a schedule of implementation.

6-7 We **recommend** that, as part of its ongoing monitoring activities, the Board audit the documentation of SCC management programs.

6-8 We **recommend** that the Board request that CEPA continue development of its Recommended Practices Manual and file it with the Board by 31 March 1997.

6-9 We **recommend** that the Board request that CEPA develop procedures for the detection and mitigation of circumferential SCC and include them in future versions of the Recommended Practices Manual.

6.4 SCC database

In May of 1995, CEPA started to develop a computerized database to collect and analyze data related to SCC. The data are taken primarily from investigative excavations and inspections for SCC, information from SCC failures, anomaly investigations and pipe replacements.

The types of data that have been included in the SCC database are the conditions which are currently known or suspected to contribute to SCC susceptibility. Once collected, the data will be analyzed for trends or correlations which may exist between the conditions and SCC susceptibility. The database contains a significant amount of information in the following categories:

- site information,
- excavation information,
- pipe information,
- magnetic particle inspection information,
- stress levels,
- environmental conditions,
- information on the most severe colony detected, and
- any general comments.

CEPA member companies have promised to participate in developing and maintaining the database. The compiling of the database with the historical data of the CEPA member companies was finished in April 1996. It will be updated yearly after each company's annual investigative programs are completed. To ensure consistency in the way the data are recorded, CEPA has developed guidelines that set out what data should be collected when conducting an SCC investigative dig. Member companies have agreed to following these guidelines, which will be incorporated into CEPA's SCC Recommended Practices Manual.

CEPA has also asked non-CEPA member companies to participate in the database. Both the CGA and CAPP have publicly expressed support for the database. CEPA has arranged for members of its SCC Working Group to meet with both associations to identify database participants and to develop ground rules for their participation. CEPA anticipated that these companies will begin to provide data by mid-1996.

The PRC*I* is also developing a database, primarily for high-pH SCC. CEPA is currently working with this organization to ensure that the two SCC databases are compatible so that the data can be shared.

In order to encourage as many Canadian pipeline companies as possible to participate, CEPA contends that the database must have some limitations on accessibility to protect the proprietary nature of the data obtained from the companies. CEPA proposes that the confidentiality of the database participants be guaranteed and that the database information not identify the contributing company.

CEPA's SCC Working Group will perform data trend analyses from the database information, supported by third party statistical expertise, if necessary. Reports of data trend analyses will be made available to regulatory agencies, participating companies, the public and research organizations on an annual basis. CEPA expects to have the first trend information available by late 1996.

CEPA's SCC database is expected to be integrated into a more comprehensive database being discussed by the Pipeline Risk Assessment Steering Committee (PRASC). Until now, the SCC database has been solely funded by the CEPA member companies. CEPA has committed to maintaining the database until the data can be integrated into the more comprehensive PRASC database.

6.4.1 Conclusions

We are of the view that the careful analysis of field experience is very important in understanding SCC. An industry-wide database on SCC is essential because it will help to identify those combinations of environmental and operating conditions that most influence SCC susceptibility. Pipeline companies, regulatory agencies, researchers and the public can be kept informed of the status of SCC field experience through the results of analyses.

Recommendations

6-10 We **recommend** that the Board request that CEPA continue to develop and maintain a database on SCC that is compatible with other international initiatives, and that CEPA encourage the participation of non-member pipeline companies.

6-11 We **recommend** that the Board require pipeline companies to provide SCC-related data to the CEPA SCC database as they acquire it.

6-12 We **recommend** that the Board request that CEPA provide the results of the first data trend analyses to the Board as proposed, including any additional trend analyses requested by the Board. As well, we **recommend** that other interested parties (for example, researchers and the public) be given the opportunity to identify the particular trend analyses that they require.

6.5 Research into SCC

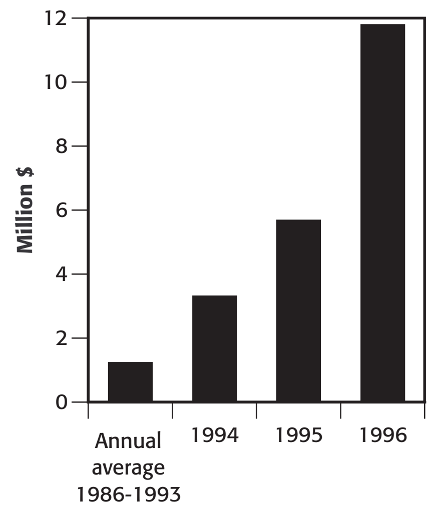
Over the past 10 years, expenditures by CEPA member companies into SCC-related research have amounted to approximately $18.7 million. In recent years, there has been a steady increase in expenditures on SCC-related research (Figure 6.8). An amount of $11.8 million was projected to be spent in 1996. Included in this is the amount of $2 million that CEPA, PRC*I*, GRI and British Gas are spending on ILI tool development.

The majority of SCC research has been focused on crack growth rates and the conditions for crack growth, rather than developing a deeper understanding of near-neutral pH SCC initiation. The growth of existing cracks presents the most immediate concern to the industry.

According to CEPA, some of the achievements in the area of near-neutral pH SCC since the previous Inquiry include [13]:

- an improved understanding of electrochemistry of near-neutral pH SCC;
- demonstration of the lack of a correlation between SCC susceptibility and pipe steel chemistry or mechanical properties;
- development of an algorithm for cathodic protection penetration under disbonded tape coatings;
- development of a crack tip chemistry model;
- establishment of a CANMET consortium to study full scale pipe tests;
- confirmation that hydrostatic retesting does not adversely affect long term pipeline integrity;
- development of NOVAProbe® and establishment of a consortium to implement use of the probe;
- development of and improvement of SCC predictive models;

Figure 6.8
Summary of research expenditures into SCC



Source: Endnote [12]

... I would say that we are further ahead in relation to understanding [near-neutral] *pH than we were at the equivalent time in the context of high pH.*

We have also benefited in another way...that being that we have had considerable benefit from having a large amount of field data in relation to the [near-neutral] *p H cracking case...* - R. Parkins.

Source: Endnote [14]

- identification of axial cracks in five pipeline systems using British Gas Elastic Wave in-line inspection tool;
- establishment of the CEPA SCC database;
- improvement of understanding of parameters affecting SCC growth;
- development of laboratory test techniques to study early life and later stages of crack growth;
- measurement of crack growth rates in the laboratory that were found to be representative of those in the field, i.e., 1×10^{-9} to 2×10^{-8} mm/s; and
- demonstration that laboratory crack growth is independent of stress from 40 per cent to 100 per cent SMYS.

In addition to the ongoing research efforts of individual CEPA member companies, CEPA has committed to fund the continued development and implementation of in-line inspection tools to detect SCC and to investigate factors controlling crack initiation. These programs involve collaboration between CEPA, PRC*I*, GRI and British Gas for the in-line inspection tool project and between CEPA and the Alberta Energy Research Council for the crack initiation project.

Table 6.3
Current and future CEPA SCC research

Research Subject	Current (in progress)	Future	Management Program Benefit Monitoring	Prioritizing	Mitigation
1. Coating disbondment	X		X		
2. Behaviour of high performance coatings		X	X		
3. Cracking environment - mechanistic studies	X		X	X	
4. Macroscopic behaviour of cracks / colonies	X		X	X	
5. Effects of surface conditions		X	X	X	
6. Effect of periodic pressure variation	X		X	X	
7. Effect of realistic pressure variation		X	X	X	
8. Residual stress		X	X	X	
9. Effect of steel composition and microstructure on susceptibility	X	X	X		
10. Cyclic stress / strain behaviour		X	X	X	
11. In-line inspection	X		X		X
12. Hydrostatic testing	X				X

Source: Endnote [15]

6.5.1 Areas for further SCC research

CEPA identified twelve areas for research as listed in Table 6.3. Seven of these are already in progress and work was expected to begin on the remaining areas in the near term. These are the research topics that the industry believes are necessary to maintain the operation of their pipelines in a safe and reliable manner. By the end of 1996, CEPA is expected to have prepared a plan for setting priorities for individual projects and the strategies for obtaining funding. The majority of these research topics have the potential to affect current pipelines with or without SCC and all are planned for funding.

6.5.2 Initiatives to promote coordination among researchers

CEPA established an SCC working group in 1994, which reports to the CEPA Engineering and Operations Committee. The group was formed to allow companies to share SCC experiences and develop pipeline industry protocols to address SCC investigation and mitigation measures. CEPA intends that the SCC Working Group will continue to manage CEPA's long-term SCC initiatives, including acting as a focal point for sharing, discussing and disseminating SCC research information. The group will also promote and support the overall coordination of efforts among companies, industry groups such as CGA and CAPP, agencies such as PRC*I* or GRI and research activities through organizations such as British Gas and the Alberta Research Council.

CAPP suggested holding an industry-sponsored meeting for the purpose of exchanging information among industry, government and academia. Such a meeting could be sponsored by the pipeline companies concerned and/or pipeline associations and would help to identify appropriate directions for future research.

6.5.3 Conclusions

It is essential to continue research into SCC. As discussed in our Conclusions to Chapter 3, many of the basic questions about SCC have not yet been answered. There is also a need to continue to develop mitigative measures to deal with SCC. Most notably, the development of a fully reliable SCC in-line inspection tool would significantly improve the industry's ability to detect SCC.

Overall, further focused research will enhance knowledge of SCC and will contribute to the development of measures to protect the public and the environment from the consequences of pipeline failures due to SCC.

The research subjects in Table 6.3 were re-examined and we concluded that the subjects with the highest potential impact on pipelines relate to:

- SCC detection,
- hydrostatic retest frequency,
- monitoring of pipe coatings, and
- database analysis.

SCC detection. The most critical item in terms of public safety is the ability to detect locations that have "significant" SCC present. Currently, there are two effective methods of detection: a predictive model and hydrostatic retesting. Both these methods have limitations. The success of finding SCC with a predictive model is dependent upon how much information is available on the pipeline system. Hydrostatic retesting only identifies areas where SCC has reached near-critical dimensions. These methods are often used together to provide a better understanding of how much SCC is present on a pipeline section.

A large amount of the pipe coated with polyethylene tape has not yet been examined. A proven in-line inspection tool that could be run through the complete pipeline system to locate areas of SCC would be very valuable. While crack detection in-line inspection tools are under development, none are yet fully reliable. High priority should be given to the further refinement of promising tools.

Hydrostatic retest frequency. For hydrostatic retesting to be effective in mitigating SCC, it is important that the frequency of the retests be such that the line does not fail between tests. Currently, the retest frequency is determined from average crack growth rates that have been estimated from field data. Additional knowledge of the factors that control crack initiation and growth rates is needed so that laboratory tests can assess the significance of the controlling factors and their influence on crack growth rates and, hence, hydrostatic retest frequencies. This should also be a priority item of research and specific areas of future research should include:

- the effect of coalescence on the latter stages of crack growth;
- the development of appropriate failure criteria for multiple crack arrays;
- the effect of crack blunting on crack growth;
- the effect of pressure reversals on the calculation of a safe test interval; and
- the effect of hydrostatic retesting on crack growth in thicker wall pipe.

Monitoring of pipe coatings. Several coatings, such as fusion bonded epoxy and extruded polyethylene, are considered to be effective in protecting pipelines from SCC. However, the long-term performance of these coatings should be continually monitored, especially at locations where SCC would be likely to develop.

Database analysis. Analysis of the CEPA SCC database should be given high priority. Rigorous analysis focused on the factors related to the incidence of SCC on various pipelines may help in refining predictive models and in locating SCC sites, as well as point to future research areas.

In summary, we support the ongoing research and coordination role of the SCC Working Group. However, we recommend that the Working Group invite SCC experts from other industries to participate in their research and also solicit expertise from a wider range of backgrounds such as metallurgy and microbiology.

Recommendations

6-13 We **recommend** that the Board request that CEPA continue its SCC research program and expand the program to include SCC experts from other industries and a wider range of disciplines.

6-14 We **recommend** that the Board request an annual status report from CEPA on SCC research activities, highlighting accomplishments to date and plans for future research indicating priorities, time lines and funding levels.

6.6 Follow-up to the Inquiry

CEPA has proposed a multi-stakeholder forum to promote broader participation in addressing SCC from all interested parties similar to the Pipeline Risk Assessment Steering Committee (PRASC). PRASC is a committee established in 1994 to review risk management in pipelines. Its membership includes CAPP, CEPA, CGA, AEUB, MIACC and the NEB.

The proposed scope of this new forum proposed by CEPA would include information sharing, coordinating research and development, promoting recommended practices and recommending possible changes to CSA standards. CEPA suggested that regulatory agencies, including the NEB, would provide valuable input and guidance as members of this group.

6.6.1 Conclusions

We feel that significant progress has been made as a result of this Inquiry. We have developed a good understanding of the issues from a variety of perspectives and a better appreciation of what pipeline safety means to Canadians. The Inquiry has served to disseminate to a much larger group than before information on SCC and mitigative measures. An annual workshop would be one method of ensuring continued dissemination of information on SCC but undoubtedly other methods exist.

We would expect that the Board will monitor progress made by industry in managing SCC by auditing the SCC management programs of companies under NEB jurisdiction and receiving reports from CEPA on the analysis of the SCC database and on SCC research activities.

Recommendations

6-15 We **recommend** that the Board request that CEPA and other industry organizations create opportunities, through conferences and workshops, for the continued sharing of information among industry, researchers, regulatory agencies and the public about SCC field experience and research developments.

Appendix I

Terms of Reference

NEB Inquiry on Pipeline Stress Corrosion Cracking

1. The Board authorized K.W. Vollman, A. Côté-Verhaaf, and R. Illing (hereafter "the Panel") pursuant to s. 15(1) of the Act to carry out an Inquiry encompassing:
   - a) an evaluation of the extent of SCC on oil and gas pipeline systems, including examination of all past SCC-related pipe failures;
   - b) a review of the current knowledge base on SCC, including past and current research and development initiatives and with specific emphasis on the mechanism of SCC, its detection, prevention, and mitigation;
   - c) an assessment of the public risk associated with SCC and the management of that risk in both the short and long term, taking into consideration:
     - i) the appropriate operating pressures for existing pipelines affected by SCC;
     - ii) other key areas of action (e.g. pipeline replacements, hydrostatic retesting, investigative excavations, and the development of internal inspection tools); and
     - iii) priorities for future research and development activity;
   - d) a consideration of initiatives which would promote coordinated efforts among stakeholders to address the SCC issue, including mechanisms to facilitate the sharing of technical data and research and development information; and
   - e) any other relevant related matters.
2. The Panel will issue a public report or reports on the findings of the Inquiry and may make recommendations regarding:
   - a) changes to the Board's Onshore Pipeline Regulations and related technical standards;
   - b) decisions or orders to be made by the Board under s. 48(1) of the Act; and
   - c) any other measures to eliminate or mitigate the hazards associated with SCC.

3. The Panel has full discretion in taking evidence or acquiring the information necessary for the purpose of making such a report and recommendations.

4. The Panel will report to the Board from time to time on the progress of its work and also to seek such changes as it may consider necessary in the above mandate.

Note: Mr. Vollman and Mr. Illing are engineers.
Mrs. Côté-Verhaaf is an economist.

Appendix II

List of Issues

NEB Inquiry on Pipeline Stress Corrosion Cracking

1. Extent and severity of SCC in oil and gas pipelines in Canada.

Preamble

In its previous Inquiry into stress corrosion cracking (MHW-1-92), the Board found no evidence that SCC was a widespread problem in Canada. Nevertheless, the Board encouraged companies to conduct investigative examinations of their systems for SCC and subsequently monitored the results of those examinations. The Board has since determined that SCC exists on a number of pipeline systems.

1.1 What is known about the extent and severity of SCC in pipelines in Canada?

The Board is seeking information on:

- the number of oil and gas pipeline systems known to have SCC;
- the number of kilometres of pipe affected by SCC;
- the history of failures due to SCC, including both operational and hydrostatic retest failures;
- the direct and indirect costs resulting from each known operational failure attributable to SCC;
- the severity of SCC found on pipelines and the criteria for assessing severity;
- any correlation of the extent, severity, and failure history of SCC with pipeline age, total length of a given system, type of coating, pipe manufacturing process, operating stress level, environment, and other factors that may contribute to the occurrence of SCC;
- whether SCC is more extensive and/or severe on gas or on oil pipelines and, if so, why; and
- why some pipeline systems have experienced more SCC failures than others.

1.2 What is the likelihood of SCC becoming more widespread and resulting in more operational failures in the future?

Responses should address what can be inferred from current Canadian and international experience with SCC on pipelines in respect of the likelihood of SCC becoming more extensive and/or severe over time.

1.3 What steps need to be taken to establish a comprehensive data base on SCC?

Responses should address the following:

- the specific information that should be collected to form a comprehensive data base on SCC; and
- who should collect the information and maintain the data base, and who should fund that service.

2. Status of research into SCC on buried pipelines.

Preamble

An understanding of the SCC mechanism is critical for developing effective preventive and mitigative measures for pipelines. In the previous Inquiry, the Board recognized the extensive level of research carried out on the nature of SCC and encouraged the continuation of those efforts.

2.1 What is the current level of understanding of the mechanism(s) for the initiation and growth of SCC on oil and gas pipelines?

Responses should address the following:

- whether there are different types of SCC (e.g., high pH and near-neutral pH);
- a discussion of the theories for the initiation and growth of SCC; the mechanical, environmental and metallurgical factors that are known to contribute to the initiation and growth of SCC; and how those factors influence SCC initiation and growth;
- whether there is a threshold stress level for the initiation of SCC; whether such a threshold level can be determined; whether it is constant along the length of a pipeline system; and the factors that affect the threshold value;
- whether there is a threshold stress intensity factor for the growth of SCC; the criterion used for the determination of the threshold stress intensity factor; whether such a threshold level can be determined; whether it is constant along the length of a pipeline system; and the factors that affect the threshold value; and

- a discussion of the research that is currently being conducted to better understand the mechanism for the initiation and growth of SCC (e.g., effect of stress levels and fluctuations, susceptibility of high strength steels, growth rates in heat affected zone (HAZ), etc.), and how the results of such research may be applied in the management of the SCC problem.

2.2 What areas pertaining to SCC need further study?

Responses should address the areas that are not fully understood and how the results of research into such areas may be applied to the management of the SCC problem. Examples include the appropriate parameter(s) to be used to describe the SCC process (e.g., J-integral), the role of hydrogen, and the interaction between mechanically-driven processes (e.g., film rupture, crack tip blunting) and chemically-driven processes (e.g., anodic dissolution).

2.3 What initiatives would promote the overall coordination of efforts among researchers addressing the SCC problem?

Responses should address whether information on research is being properly disseminated; suggest mechanisms that would facilitate the sharing of information; discuss who should be funding the research; and the role of funding parties in deciding how the information is shared.

2.4 What expenditures have been made and are projected to be made on research related to SCC?

Responses should provide information on how much has been spent in the last 10 years; in 1994; in 1995; what funding commitments have been made for future research; and whether funding for future research is appropriate.

3. Detection of SCC on buried pipelines.

Preamble

The development of a reliable in-line inspection tool for the detection of SCC on pipelines would significantly enhance the ability of companies to eliminate SCC defects on their systems and to prevent operational failures. Evidence submitted in the previous Inquiry indicated that a considerable amount of research had been aimed at developing such a tool, but that further work was required. Until such a tool is developed, companies must rely on a predictive soils model to identify SCC-susceptible locations.

3.1 Would the development of an in-line inspection tool for detecting cracks be a viable long-term solution to the SCC problem?

Responses should address the following:

- the capability of state-of-the-art in-line inspection tools for the detection of cracks, including available field data that demonstrates such capability;
- the limitations and restrictions on the practical use of such tools (e.g., size limitations, suitability for use on liquid and gas lines);
- whether such tools are currently commercially available and, if not, when they are expected to be available;
- the percentage of affected pipeline systems that could accommodate such tools;
- whether adequate commitment and funding is assured for the development of promising in-line inspection tools to operational and commercial viability, including the commitments being made and who is making them;
- the immediate and long-term costs associated with in-line inspection for SCC (including development costs for the tools, the cost of making each affected pipeline system able to accommodate such tools, etc.); and
- whether in-line inspection tools will be cost-competitive with other detection techniques.

3.2 How effective are predictive soils models at finding SCC on buried pipelines?

Responses should address the following:

- the parameters included in predictive soils models;
- the effectiveness of such models in finding SCC-susceptible locations, including field data that demonstrates such effectiveness (e.g., ratio of finds/predictions);
- whether such models are generally applicable or limited to certain geographic areas;
- other possible limitations of such models; and
- the immediate and long-term costs associated with predictive soils models.

3.3 What other methods are available for finding SCC on buried pipelines?

Responses should address the theory and principles behind other methods; their effectiveness at detecting SCC on pipelines; the limitations of those methods; and the associated costs.

4. Mitigative measures for SCC on buried pipelines.

Preamble

The previous Inquiry evaluated the effectiveness of certain mitigative measures (i.e., hydrostatic retesting, pressure reduction, selective pipe replacement, investigative excavations and repair) in preventing operational failures. Since then, additional experience has been gained on the use of these techniques and other techniques have been identified.

4.1 How effective are the mitigative measures set out below at preventing operational failures and how viable are they as long-term solutions to the SCC problem?

In addition to the specific information requested below, each response should also address the comparative advantages and disadvantages (including limitations on use, circumstances wherein a particular measure may not be viable as a long-term approach, etc.), as well as the immediate and long-term costs associated with each mitigative measure:

4.1.1 Hydrostatic Retesting

Responses should address the following:

- the size of defects that can survive a retest;
- the accuracy and reliability of current life-prediction models when applied to SCC defects, including the limitations of these models (e.g., can the interaction between cracks be predicted and quantified?);
- the appropriate hydrostatic retest parameters: stress level, test duration, test frequency, etc.;
- whether repeated hydrostatic retests might impair the long-term integrity of a pipeline system;
- whether affected pipelines should be hydrostatically retested throughout, or only in SCC-susceptible areas;
- the advantages/disadvantages of hydrostatic retesting as a means of preventing operational failures; and
- the sources of information on the effects of hydrostatic retesting; i.e., laboratory data or field evidence.

4.1.2 Investigative Excavations and Repair

Responses should address the following:

- the appropriate criteria for repair vs cut-out of SCC-affected pipe, and the rationale and technical data justifying the use of such criteria;
- the appropriate repair methods (e.g., grinding, re-coating, sleeving, etc.); the rationale and technical data justifying the use of such repair methods; the criteria for selecting which repair method to use; the limitations of each method;
- the effectiveness of excavations/repairs in preventing operational failures (e.g., have repaired sections ever failed during normal operation?); and
- whether repeated excavations and repairs might impair the long-term integrity of a pipeline system.

4.1.3 Selective Pipe Replacements

Responses should address the following:

- the guidelines for choosing replacement pipe (e.g., should replacement pipe be thicker? by how much? what type coating should be used? etc.);
- the critical locations along a pipeline that should be selected for pipe replacements; (e.g., those in proximity to dwelling units, to roads, to railways, to places of public assembly, to sensitive environmental areas, etc.) and the rationale for such selections;
- the appropriate distance criteria for pipe replacement, and the rationale and technical data supporting the use of such criteria;
- the factors that should be taken into consideration in determining the appropriate distance criteria (e.g., safety, property damage, environmental impacts);
- whether selective replacements should be applied system-wide or in SCC-susceptible locations only; and
- technical data that provides a measure of the effectiveness of selective replacements in preventing operational failures.

4.1.4 Pipe Recoating

Responses should address the available technology, the cost of recoating versus replacing the pipe, and effectiveness in arresting and preventing growth of SCC.

4.1.5 Limitations on Operating Conditions

Responses should consider at least the following operating conditions: operating pressure/stress levels, operating temperatures, stress fluctuations, and cathodic protection levels, and address the following:

- whether there are correlations between operating conditions and crack growth rates;
- whether limitations on operating conditions should differ between oil and gas pipelines;
- the rationale and technical data supporting limitations on operating conditions; and
- the practicality of imposing such limitations.

4.2 Are there other mitigative measures for SCC on buried pipelines?

Responses should discuss other mitigative measures that should be considered for preventing operational failures.

5. Prevention of initiation of SCC on buried pipelines.

Preamble

The previous Inquiry was directed primarily at examining certain methods for controlling the growth of SCC on pipelines known to have or suspected of having SCC. Other than an examination of the existence of a threshold stress level for the initiation of SCC, there was no attempt to determine what other methods should be considered to prevent the initiation of SCC on new pipeline systems or unaffected portions of existing systems.

5.1 Which methods or practices would contribute to the prevention of SCC on new and existing pipelines?

Responses should address the following:

- the metallurgical characteristics that affect the formation of SCC;
- the aspects in the manufacture of pipe that can be controlled to prevent SCC;
- the effectiveness of different types of coatings in preventing SCC;
- the modifications that can be made to the environment (soil, topography, electrochemical environment, microbial activity, etc.) that decreases the susceptibility of a pipeline to SCC;
- the construction practices that are effective in preventing SCC;

- the operating practices (e.g., operating pressures, pressure/stress fluctuations, operating temperature, cathodic protection levels, etc.) that are effective in preventing SCC; and
- an estimate of the immediate and long-term costs associated with the various preventive measures.

6. Safety of the public and of company employees, and protection of the environment and property.

Preamble

The previous Inquiry resulted in a number of changes to the Pipeline Maintenance Program of TransCanada PipeLines Limited to address the safety risk posed by SCC. The approved program included hydrostatic retesting, proximity pipe replacements, investigative excavations and research. The Board encouraged other companies to carefully review the TransCanada experience and to examine their own systems for SCC when opportunities occur while carrying out other inspection, repair, or maintenance activities.

Since that time, the development of an internal inspection device has continued, the predictive soils models have been refined, more is known about SCC, and other pipeline systems have been found to have SCC. As a result of these changing circumstances, the decision on how best to ensure the safety of the public and of company employees, and the protection of the environment and property should be re-evaluated.

6.1 How do the current integrity management practices of pipeline companies address the risk from SCC?

Responses should explain the following:

- how susceptible portions of the pipeline system are identified;
- the criteria used to assess and manage risk;
- how mitigative techniques are selected and employed;
- whether companies have initiated ongoing programs to detect SCC; and
- what components should be included in an effective integrity management program for SCC.

6.2 What changes should be made to current integrity management practices?

Responses should be based on what has been learned about SCC since existing integrity management practices were put into place, and should address the following:

- the techniques that could be used to monitor the extent and severity of SCC on operating pipelines;
- the criteria to be used in evaluating the suitability of a pipeline for continued operation; and
- long-term strategies for dealing with pipelines with SCC (e.g., periodic recertification, use of buffer zones, changes to codes and regulations).

6.3 Are current emergency response practices adequate for SCC-susceptible lines?

Responses should discuss industry practices in terms of leak detection, shutdown and isolation of failure sites and emergency preparedness.

Appendix III

Definition of "Significant" SCC

CEPA stated [1] that it would adopt the definition of "significant" SCC as follows:

Cracks in a colony are assessed to be "significant" if the deepest crack, in a series of interacting cracks, is greater than 10 per cent of wall thickness and the total interacting length is equal to or greater than 75 per cent of the critical crack length of a 50 per cent throughwall crack at a stress level of 110 per cent SMYS. The procedure for assessing the existence of "significant" cracks is detailed as follows:

1. Determine the critical length for rupture of a 50 per cent throughwall defect at 110 per cent SMYS. This critical length is a function of line specific pipe characteristics and nominal properties and can be determined using such analysis algorithms as:

   i) Pipe Axial Flaw Failure Criteria - developed by Battelle Memorial Institute for the PRC*I*, and

   ii) CorLAS™ - developed by CC Technologies.

2. Determine the cumulative interacting length of the cracks. The interaction is dependent upon the circumferential and axial separation between individual cracks. The interacting circumferential distance between two cracks is evaluated using the following formula:

$$\boldsymbol{Y} \leq \mathbf{0.14} \quad \frac{(l_1 + l_2)}{2}$$

   where Y = actual circumferential separation between two cracks

   l_1, l_2 = crack lengths

   In order for two cracks to be interacting, the axial separation between them must be evaluated using the following formula:

$$\boldsymbol{X} \leq \mathbf{0.25} \quad \frac{(l_1 + l_2)}{2}$$

   where X = actual axial separation between two cracks

   l_1, l_2 = crack lengths

3. If one of the cracks within the cumulative interactive length has a depth greater than 10 per cent of wall thickness, compare the interacting length of the colony to the critical length calculated in Step 1. If the interacting length exceeds 75 per cent of the critical length, the colony is considered "significant".

Appendix IV

Assessment of Failure Criteria

In order to quantify the relationship between critical defect size and pressure in pipelines, Battelle conducted an extensive series of burst tests in the early 1970s and developed an assessment methodology for analyzing axial flaws in pipelines [1]. The Battelle method, sometimes referred to as the log-secant criterion, was based on a strip-yield model and empirically derived for surface axial flaws. Since its inception, the log-secant failure criterion has been used extensively in the pipeline industry as a conservative method of assessing the failure pressure for known defect dimensions.

More recently-developed failure criteria incorporate elastic-plastic fracture mechanics principles, the understanding of which has improved significantly in the past two decades. In addition to the log-secant criterion, other failure criteria for axial flaws in pipelines that were considered in the Inquiry were the Pipe Axial Flaw Failure Criterion (PAFFC) developed at Battelle [2], the Level 2 Strip Yield Model developed at CANMET [3] and the CorLas™ model developed by Cortest [4].

CEPA provided calculations of predicted failure pressures for 14 given crack sizes [5]. The data used in the calculations are representative of the range of material properties, flaw shapes, and pipe diameters in which SCC failures have occurred in Canada.

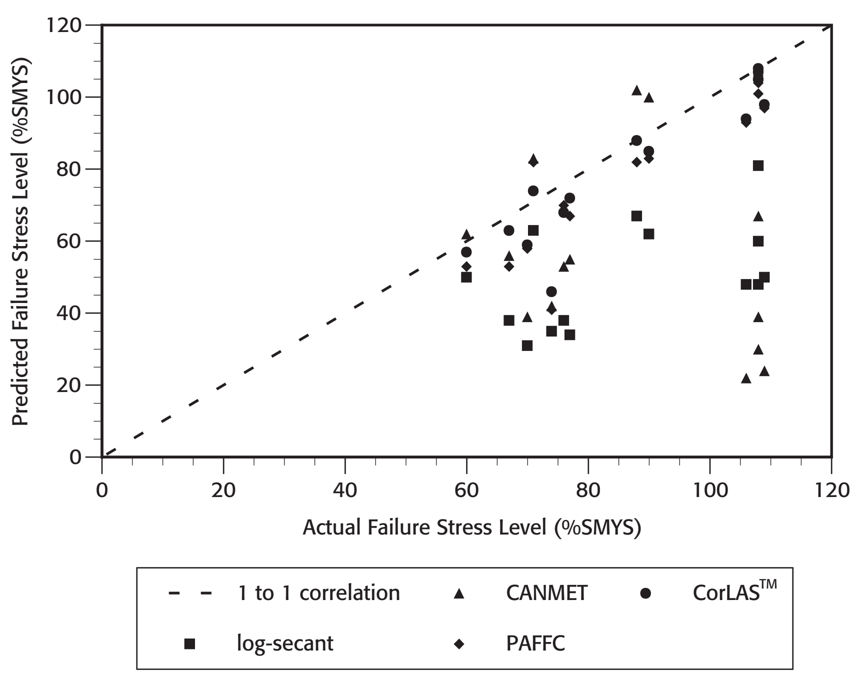
The results were used to plot scatter graphs of predicted vs. actual failure pressures for the four failure criteria (Figures IV.1 and IV.2). Points under the dashed lines indicate conservative predictions; conversely, points above are non-conservative. Figure IV.1 shows that most of the failure pressures predicted by the different failure criteria are conservative and that there is a significant amount of scatter in the results.

Figures IV.2(a) and IV.2(b) show that, for this set of data, the log-secant and CANMET criteria can be very conservative, with significant variances in the level of conservatism. In addition, the CANMET criterion was not consistently conservative. In comparison, Figures IV.2(c) and IV.2(d) show much improved predictability for both the CorLAS™ and PAFFC criteria, with CorLAS™ giving comparatively better accuracy. The figures illustrate the inconsistency and significant amount of conservatism that is possible in the application of these failure criteria.

It must be emphasized that the observations noted above with respect to each failure criterion are valid for the specific set of field data for which the calculations were made and may not necessarily hold true for other sets of data. Each failure criterion is developed on the basis of certain assumptions and generally has a limited range of applicability. The predictive capability of a failure criterion improves if the specific situation under consideration is consistent with those assumptions and is within that range of applicability.

For example, in a study conducted by Battelle for TCPL, it was concluded that the log-secant criterion is not appropriate for assessing pipeline failure pressures for lines containing SCC, such as has occurred on the TCPL system [6]. The inconsistent and overly conservative predictions of failure pressure were attributed primarily to the effect of multiple cracking that is associated with SCC, as compared to the single rectangular axial flaw assumed in deriving the log-secant criterion. The study also identified the empirical calibration of the criterion as contributing to the observed conservatism and inconsistency. In another study conducted by Battelle for TCPL, the results suggest that the presence of multiple cracks effectively reduces the crack driving force below that for a single crack [7]. Therefore, failure criteria based on a single crack will tend to underestimate failure pressures where multiple cracks are present. According to TransCanada, Battelle is currently working on developing a correction factor for single-crack failure criteria that will improve its predictive accuracy for multiple cracks.

Figure IV.1
Predicted vs. actual failure stress levels for various failure criteria



Source: Data from endnote [5]

Figure IV.2 (a) Log-secant failure criterion predicted vs. actual failure stress levels

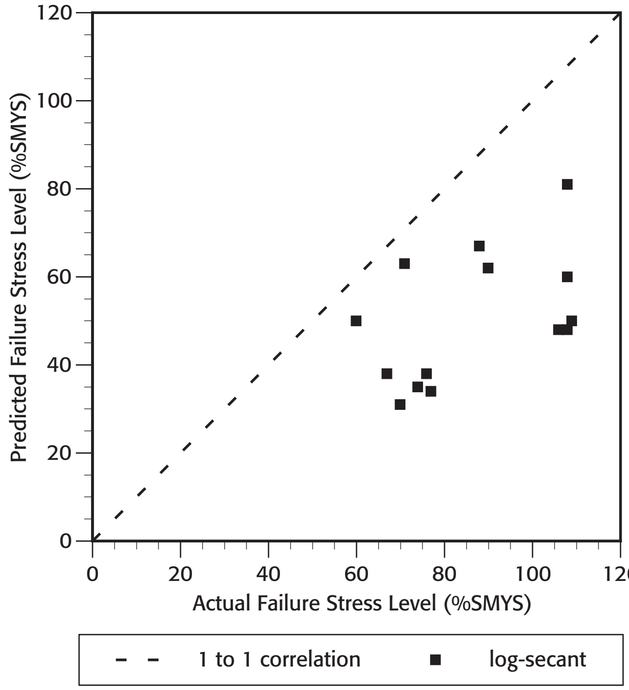


Figure IV.2 (b) CANMET failure criterion predicted vs. actual failure stress levels

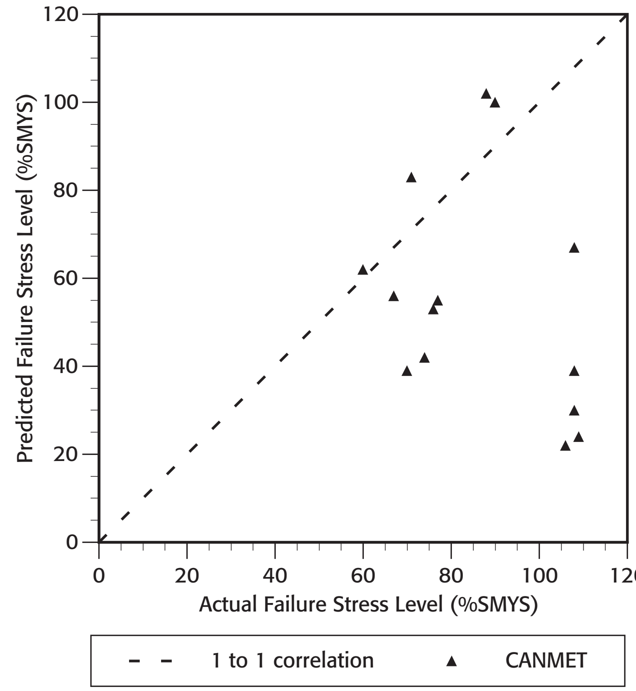


Figure IV.2 (c) Pipe Axial Flaw Failure Criterion predicted vs. actual failure stress levels

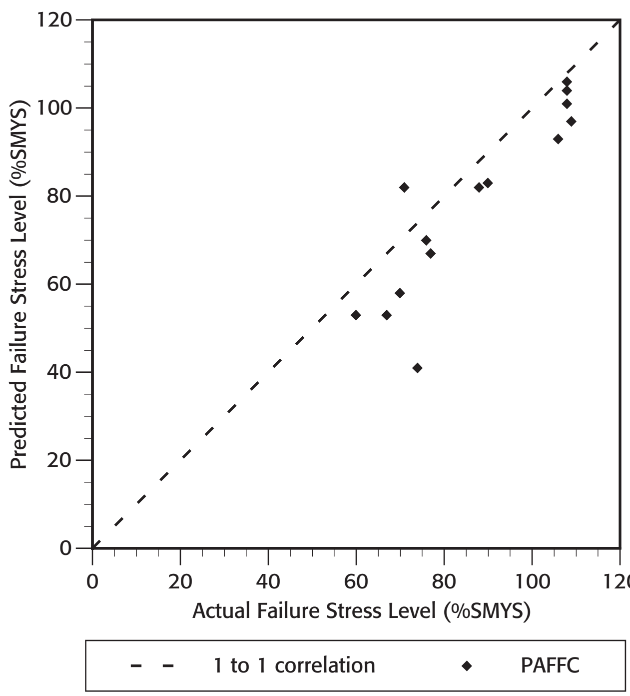
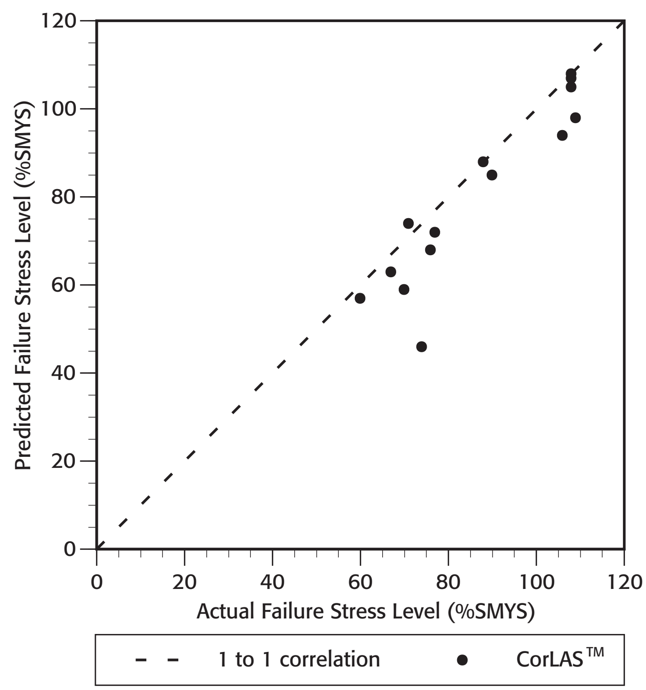
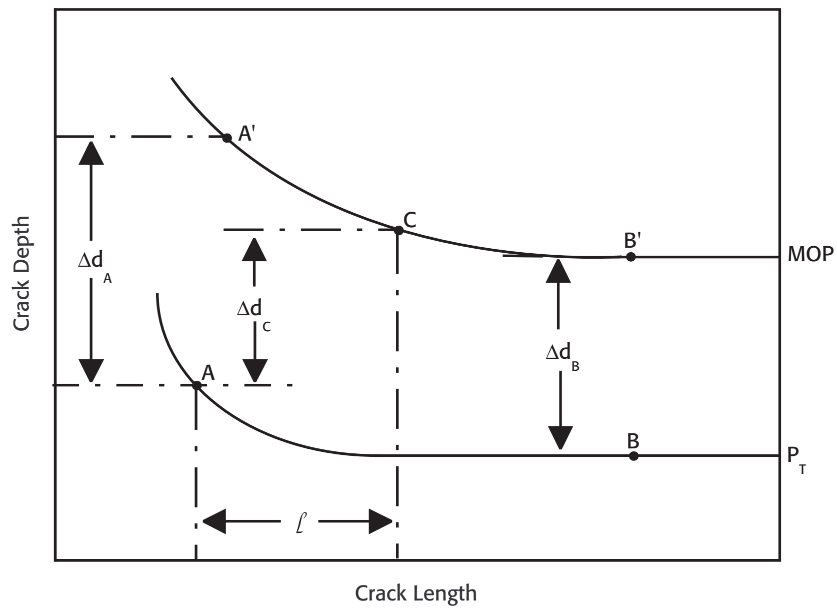


Figure IV.2 (d) CorLAS™ failure criterion predicted vs. actual failure stress levels



Source: Data from endnote [5]

Figure IV.3
Critical crack sizes at hydrostatic test pressure and at maximum operating pressure



Once an appropriate failure criterion has been chosen, critical crack sizes can be calculated for the test pressure and the MOP of the pipeline. Figure IV.3 shows a typical graph of the critical crack sizes for two stress levels, corresponding to the hydrotest pressure and the MOP. It is a plot of crack depth versus crack length and represents the families of crack sizes that are critical at the test and maximum operating pressure. For example, both the short, deep crack, A, and the long, shallow crack, B, are critical at the test pressure.

After a hydrotest, it can be assumed that no cracks remain in the pipeline whose dimensions lie above the curve for P_T. Over time, cracks A and B will grow to A′ and B′, respectively, where the latter are critical at the operating pressure of the pipeline. The difference in depth between A′ and A, Δd_A, is the margin for growth in the depth direction that is necessary for crack A to fail in service. Similarly, for crack B, the crack growth margin is Δd_B. Unless there is data available (e.g., previous failures, ILI data) to support the assumption of a specific critical crack length, the minimum Δd between the two curves should be used to arrive at a conservative value for a safe test interval. The assumption of an infinitely long crack would normally lead to conservative estimates of Δd.

Another advantage of assuming an infinitely long crack is that any further growth in crack length that might occur between tests becomes irrelevant and, consequently, any coalescence of cracks will not affect the calculations of a safe test interval. If, subsequent to a hydrotest, crack A in Figure IV.3 were to coalesce with a crack of length ℓ, the total length of the new crack would be significantly greater. Consequently, the critical crack depth at MOP would be smaller and the amount of growth in the depth direction that is necessary for crack A to fail in service would be Δd_C, which is significantly less than Δd_A. By assuming a longer crack or one of infinite length, the effect of any coalescence is minimized or eliminated altogether.

CEPA has taken the position, based on observations of field and laboratory cracks, that coalescence for low pH SCC occurs in the early stages of growth when cracks are small and then the coalesced crack continues to grow as a single crack. According to Beavers, the examination of fracture surfaces of failed pipelines indicate that the early stages of growth occur in the axial direction, during which time smaller cracks coalesce, and that the latter stages are characterized by growth in the depth direction [8]. Parkins indicates that laboratory results of specimens taken to failure suggest the same tendency for coalescence to occur early [9]. However, the Panel notes that this apparent tendency to coalesce in the early stages of growth does not preclude the scenario wherein cracks coalesce subsequent to a hydrotest, but do not lead to immediate failure. That situation could still occur and lead to nonconservative estimates for test intervals.

In summary, the failure criterion selected must be appropriate for the specific situation under consideration. It is therefore essential that the assumptions underlying a failure criterion, as well as its range of applicability, be fully understood and considered. Secondly, in the absence of reliable data regarding crack dimensions, the minimum Δd should be used to arrive at a conservative value for a safe test interval.

Appendix V

Glossary

anodic dissolution	localized corrosion in the presence of an electrical current
anchor pattern	roughing of the pipe surface in order to allow better adhesion of the coating
anaerobic soil	soil lacking in oxygen
aerobic soil	soil containing oxygen
Barlow's formula	relates the pressure in a pipe to the circumferential (hoop) stress as a function of the diameter and wall thickness
brittle fracture	pipeline failure with little plastic deformation at fracture surface
cathodic protection (CP)	method of controlling or reducing corrosion by applying a voltage to the pipe through the soil
class location	geographic area classified according to its approximate population density in a region 200 m on both sides of the centreline of any continuous 1.6 km of pipeline
coating disbondment	separation of coating from the pipe surface
cold expansion	mechanical expansion of pipe after forming and welding by 1 to 1.5 per cent to round out and size the pipe diameter
collinear	lying along the same line (coaxial)
compressive stress	stress that compresses or shortens the material
corrosion	degradation of steel by chemical or electro-chemical dissolution that occurs as a result of the interaction of the steel with its environment
crack blunting	plastic deformation of the crack tip due to an overload
crack coalescence	joining of two cracks that are in close proximity to form one longer crack
cracking	mechanical splitting into parts

cyclic softening	after a number of pressure cycles, many steels exhibit plastic strains at stress levels below those at which they would normally occur, i.e., the yield stress
diffusion	passage of a substance into a body (e.g., hydrogen into steel)
“dirty” steel	term used to denote a steel containing a high number of non-metallic inclusions
discrete repair	a short segment of pipeline identified to be repaired
dissolution	decomposition of steel into parts
double submerged arc weld (DSAW)	weld using filler metal passes on the inside and outside of the pipe
ductility	a measure of the capability of a material to be deformed plastically before fracturing
elastic limit	see proportional limit
electric potential	voltage existing between the pipe and its environment
electric resistance weld (ERW)	weld formed by resistance heating of the two edges of a pipe and then forcing them together to create a solid state weld
electrolyte	liquid that conducts electricity
fatigue	mechanism leading to fracture as a result of repeated or fluctuating stresses
flash-welded	distinct type of ERW pipe, made from individually rolled plates formed into cans before being welded
fracture mechanics	study of the physics of crack initiation and growth in a material
fracture toughness	a measure of a material’s resistance to crack extension, either slow or rapid
free corrosion potential	electric potential that exists in the absence of an applied potential with corrosion occurring
free surface	a surface with one side not constrained by adjacent metal, just air
girth weld	circumferential weld joining two sections of pipe
high vapour pressure (HVP) liquid	hydrocarbons or hydrocarbon mixtures in the liquid or quasi-liquid state with a vapour pressure in excess of 107 kPa absolute at 38ºC

holiday	a hole or puncture in the coating of a pipeline
hoop stress	stress around the circumference of a pipe (i.e., perpendicular to the pipe length) which results from internal pressure
hydrogen embrittlement	a condition of low ductility in metals resulting from the absorption of hydrogen
hydrolysis	decomposition of a chemical compound by reaction with water
hydrostatic test	pressure test of a pipe or pressure vessel using water as the pressurizing medium
in-line inspection (ILI) or internal inspection	the inspection of a pipeline from the interior of the pipe
in-line inspection tool	the device or vehicle, also known as an intelligent or smart pig, that uses a nondestructive testing technique to inspect the wall of a pipe from the inside
"insignificant" SCC	SCC that is not large enough to be classified as "significant"
intergranular	crack growth or crack path that is between the grains of a metal
J-integral	a fracture mechanics parameter relating crack size, geometry and stress acting on a crack. This parameter accounts for plasticity effects in crack growth
launcher	a pipeline facility used for inserting a pig into a pressurized pipeline
leak	a small opening, crack or hole in a pipeline causing some product loss, but not immediately impairing the operation of the pipeline
loading rate	rate at which pressure increases in a pipeline
low vapour pressure (LVP) liquid	hydrocarbons or hydrocarbon mixtures in the liquid or quasi-liquid state with a vapour pressure of 107 kPa absolute or less at 38°C
magnetic particle inspection (MPI)	a nondestructive examination procedure for locating surface flaws in steel using fine magnetic particles and magnetic fields

microplastic strain	a small area of plastic strain usually on the pipe surface, such as in a pit or other areas where the strain is locally confined, that does not spread through the wall thickness resulting in gross plastic deformation of the pipe
microstructure	structure of metals and alloys as revealed after polishing and etching them; hot rolled steels usually consist of bands of ferrite (iron) and pearlite (carbon) but may contain other microstructures such as martensite (hard brittle grains) or bainite (not as hard or brittle as martensite)
mill scale	scale remaining on the surface of the pipe due to steel manufacturing process
non-metallic inclusions	a particle of foreign material in a metallic matrix; usually the foreign material is an oxide, sulfide or silicate but may be of any substance foreign to the matrix
nucleate	initiate, such as start the growth of a crack
off-line inspection	inspection of a pipeline section that is removed from service; accomplished by the installation of temporary launchers and receivers
on-line inspection	inspection of a pipeline section while it is in service; accomplished by the use of permanently installed launchers and receivers
passivity	function of the electrochemical environment where a passive or protective film forms
pH	measure of the acidity or alkalinity of a substance
pig	a generic term signifying any independent, self-contained device, tool or vehicle that moves through the interior of the pipeline for inspecting, dimensioning or cleaning purposes
pigging	see in-line inspection
pressure	level of force per unit area exerted on the inside of a pipe or pressure vessel
pressure reversal	failure of a defect (e.g., crack) at a pressure level below the maximum level reached on a prior loading (e.g., hydrostatic retest)

proportional limit	maximum stress a material is capable of sustaining without any permanent (plastic) deformation upon release of the stress (also know as elastic limit)
proximity replacements	see selective pipe replacements
R-ratio	ratio of the minimum to maximum stress to characterize the pressure fluctuations experienced in cyclic loading
receiver	a pipeline facility used for removing a pig from a pressurized pipeline
redox potential	potential of the soil for oxidation to occur; measures the oxygen that is available to combine with other compounds
residual stress	stress present in an object in the absence of any external loading; results from manufacturing process, heat treatment, or mechanical working of material
rupture	the instantaneous tearing or fracturing of pipe material causing large-scale product loss and immediately impairing the operation of the pipeline
selective pipe replacements	pipe replacements which are undertaken adjacent to critical areas such as dwellings
SMYS	specified minimum yield strength; the minimum yield strength prescribed by the specifications or standard to which pipe is manufactured
sour gas	natural gas containing hydrogen sulphide in such proportions as to require treating in order to meet domestic sales gas specifications
strain	increase in length of a material expressed on a unit length basis (e.g., inches per inch)
strain hardening	an increase in hardness and strength caused by plastic deformation at a temperature below the recrystallization range
stress	tensile or compressive force per unit area in the pipe wall as a result of the loads applied to the structure
stress associated dissolution	see anodic dissolution
stress focused dissolution	see anodic dissolution

stress intensity factor	a fracture mechanics term relating the crack size, geometry and stress acting on a crack
stress raiser or concentration	a change in contour, discontinuity, gouge or notch that causes the local increases in the stress in a pipe
stress relief	reduction of the residual stresses either through a mechanical overload or through an elevated temperature (i.e., 200 to 450°C for a period of time)
"significant" SCC	SCC that is deeper than 10 per cent of the pipe wall thickness and is as long as, or longer than, the critical crack length of a 50 per cent throughwall crack at a stress level of 110 per cent of the pipe's SMYS
subcritical crack	a crack that is not large enough to cause a failure of a pipeline at a given pressure
tensile stress	stress that elongates the material
terrain conditions	the soil type, drainage and topography at a given location
thermal flux	a measurement of heat intensity
thermal stress relief	process of relieving residual stress by elevating the steel temperature for a defined period of time
transducer	a device for converting energy from one form to another; for example, in ultrasonic testing, conversion of electrical pulses to acoustic waves and vice-versa
transgranular	crack growth or crack path that is through or across the grains of a metal
TÜV Rheinland	an organization authorized by the German Government to verify the compliance with directives defined by Regulations covering the operation and inspection of pipelines in Germany
weld seam	the longitudinal weld in pipe, which is made in the pipe mill
yield strength	stress level at which a material exhibits a specified deviation from linear proportionality of stress and strains (usually 0.5 per cent strain)

Endnotes

Chapter 1

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Chapter 2

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Chapter 3

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3. CEPA (1996). *Submission to the National Energy Board, Proceeding MH-2-95*, Vol. 1, Issue 6, fig. 6.1.

4. TCPL (1996). *Closing Statement to Proceeding MH-2-95*, p 3.

5. CEPA (1996). *Submission to the National Energy Board, Proceeding MH-2-95*, Vol. 1, Issue 1, table 1.1 (revised in response to Undertakings given by Mr. Delanty to Mr. McCarthy and by Mr. Argument to Mr. McCarthy at MH-2-95 Hearing Transcript, 15 April 1996, pp 49-50). Additional information on Federated's 1993 leak provided at MH-2-95 Hearing Transcript, 22 April 1996, p 688.

6. *Ibid.*, p 21.

7. CEPA (1996). *Response to National Energy Board Information Request #1 of Proceeding MH-2-95* and *Submission to the National Energy Board, Proceeding MH-2-95*, Vol. 1, Issue 1, table 1.2 (revised in response to Undertaking given by Mr. Argument to Mr. McCarthy at MH-2-95 Hearing Transcript, 15 April 1996, p 54).

8. IPL subsequently retested the section of their system where the failure occurred.

9. CEPA (1996). *Response to National Energy Board Information Request #20 of Proceeding MH-2-95.*

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11. *Ibid.*, p 15.

12. *Ibid.*, Issue 2, p 29.

13. CEPA (1996). *Final Argument to Proceeding MH-2-95*, p 6.

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