

# Risk-Based Inspection Base Resource Document

API PUBLICATION 581  
FIRST EDITION, MAY 2000



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# **Risk-Based Inspection Base Resource Document**

## **Downstream Segment**

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## Risk-Based Inspection—Base Resource Document

### Section 0—Introduction

#### 0.1 BACKGROUND

The American Petroleum Institute (API) Risk Based Inspection Project was initiated in May 1993 by an industry sponsored group to develop practical methods for Risk Based Inspection. This sponsor group was organized and administered by the API and included the following members: Amoco; ARCO; Ashland; BP; Chevron; CITGO; Conoco; Dow Chemical; DNO Heather; DSM Services; Equistar Exxon; Fina; Koch; Marathon; Mobil; Petro-Canada; Phillips; Saudi Aramco; Shell; Sun; Texaco; and UNOCAL.

The Base Resource Document (BRD) clearly states there are limitations to the methods presented within it, and lists some of those limitations. The BRD states “to accurately portray the risk in a facility... a more rigorous analysis may be necessary, such as the traditional risk analysis described...”

According to the proposal for the API sponsor group project, the BRD, and the methods in it were “to be aimed at an inspection and engineering function audience.” The BRD is specifically not intended to “become a comprehensive reference on the technology of Quantitative Risk Assessment (QRA).”

For failure rate estimations, the proposal promised “methodologies to modify generic equipment item failure rates” via “modification factors.” In addition, the proposal specified that for this activity, “the contractor would seek to involve specialized expertise by drawing upon API Committee on Refinery Equipment member resources for this task.” This was done in the project by the formation of working groups of sponsor members who directed the development of the modification factors, with assistance by the contractor.

For consequence calculations, safety, monetary loss, and environmental impact were all to be included. For safety evaluations, the proposal noted that existing algorithms in AIChE CPQRA guidelines are “complex and are best suited for use in a computerized form.” It was proposed that “for ease of use the safety consequences be limited to the evaluation of: burning pools of liquids, ignited high velocity gas and liquid releases, explosions of vapor clouds, and toxic impacts.”

The result of the BRD project and subsequent projects has been the development of simplified methods for estimating failure rates and consequences of pressure boundary failures. The methods are aimed at persons who are not expert in QRA. Subsequent computer programs have been developed to further ease the application of the BRD methods.

#### 0.2 EXECUTIVE SUMMARY

**0.2.1 Risk-Based Inspection (RBI)** is a method for using risk as a basis for prioritizing and managing the efforts of an inspection program. In an operating plant, a relatively large

percentage of the risk is associated with a small percentage of the equipment items. RBI permits the shift of inspection and maintenance resources to provide a higher level of coverage on the high-risk items and an appropriate effort on lower risk equipment. A potential benefit of a RBI program is to increase operating times and run lengths of process facilities while improving, or at least maintaining, the same level of risk.

The purposes of the Risk-Based Inspection Program are summarized as follows:

- a. Screen operating units within a plant to identify areas of high risk.
- b. Estimate a risk value associated with the operation of each equipment item in a refinery or chemical process plant based on a consistent methodology.
- c. Prioritize the equipment based on the measured risk.
- d. Design an appropriate inspection program.
- e. Systematically manage the risk of equipment failures.

The RBI method defines the risk of operating equipment as the combination of two separate terms: the consequence of failure and the likelihood of failure.

The Base Resource Document includes a qualitative analysis that allows operating units to be quickly prioritized for further risk analysis. The result of the qualitative analysis positions the unit within a five-by-five risk matrix, which rates it from lower to higher risk.

**0.2.2** The likelihood analysis is based on a generic database of failure frequencies by equipment types which are modified by two factors that reflect identifiable differences from “generic” to the equipment item being studied. The Equipment Modification Factor reflects the specific operating conditions of each item, and the Management Modification Factor is based on an evaluation of the facility’s management practices that affect the mechanical integrity of the equipment. The management systems evaluation tool is based on API guidelines and is included as a workbook of audit questions in the Base Resource Document.

The likelihood analysis includes a series of Technical Modules that assess the effect of specific failure mechanisms on the probability of failure. The Technical Modules serve four functions:

- a. Screen the operation to identify the active damage mechanisms.
- b. Establish a damage rate in the environment.
- c. Quantify the effectiveness of the inspection program.
- d. Calculate the modification factor to apply to the generic failure frequency.

**0.2.3** The consequences of releasing a hazardous material are calculated by:

- a. Estimating the release rate based on the developed scenarios.
- b. Predicting the outcome.
- c. Applying effect models to estimate the consequences.

Flammable, toxic, environmental and business interruption effects are covered in the Risk-Based Inspection methodology. A Quantitative RBI Workbook is provided to guide the user step-by-step through the calculations for both the likelihood and consequence analyses.

**0.2.4** The likelihood and consequence are combined to produce an estimate of risk for each equipment item. The items can then be ranked based on the risk calculation, but the likelihood, consequence, and risk are all stated separately, identifying the major contributor to risk.

Guidelines are provided to develop and modify an inspection program so it will appropriately manage the risks that have been identified in the risk calculation and prioritization steps. A simple method is presented for categorizing inspection effectiveness and estimating the probability that the inspection plan will identify the true damage state in a piece of equipment. The effects of alternate inspection plans, and an approach to developing an inspection program, are presented.

Worked examples of actual plant equipment are provided to demonstrate the methodology. A Risk-Based Inspection study, sponsored by the full committee, has been performed at a Shell facility. This study will serve as a pilot program for the group.

Future work might include development of an industry failure database, software to support Risk-Based Inspection, and expanding the program to fit into other industry initiatives, including Reliability Centered Maintenance (RCM).

## Section 1—Scope

### 1.1 GENERAL

This document is about using risk as a basis for prioritizing and managing an inspection program, where equipment items to be inspected are ranked according to their risk. In nearly every situation, once risks have been identified, alternate opportunities are available to reduce them. On the other hand, nearly all major commercial losses are the result of a failure to understand or manage risk.

It is important to understand that the Risk-Based Inspection methodology, as presented in this Base Resource Document, represents only one of many possible approaches to the use of risk as an inspection criteria. As with all forms of risk assessment, many approaches are valid depending on the assessment goals and level of detail desired.

The RBI methodology provides the basis for managing risk by making an informed decision on inspection frequency, level of detail, and types of NDE. In most plants, a large percent of the total unit risk will be concentrated in a relatively small percent of the equipment items. These potential high-risk components may require greater attention, perhaps through a revised inspection plan. The cost of the increased inspection effort can sometimes be offset by reducing excessive inspection efforts in the areas identified as having lower risk. With a RBI program in place, inspections will continue to be conducted as defined in existing working documents, but priorities and frequencies will be guided by the RBI procedure.

The purposes of a (RBI) program are as follows:

- a. To provide the capability to define and measure risk, creating a powerful tool for managing many of the important elements of a process plan;
- b. To allow management to review safety, environmental and business-interruption risks in an integrated, cost-effective manner;
- c. To systematically reduce the likelihood of failures by making better use of the inspection resources; and
- d. Identify areas of high consequence that can be used for plant modifications to reduce risk (risk mitigation).

### 1.2 AN INTEGRATED MANAGEMENT TOOL

The RBI program presented in this Base Resource Document takes the first step toward an integrated risk management program. In the past, the focus of risk assessment has been on-site safety-related issues. Presently, there is an increased awareness of the need to assess risk resulting from:

- a. On-site risk to employees.
- b. Off-site risk to the community.
- c. Business interruption risks.
- d. Risk of damage to the environment.

The RBI approach allows any combination of these types of risks to be factored into decisions concerning when, where, and how to inspect a process plant.

RBI is flexible and can be applied on several levels. Within this document, RBI is applied to the equipment within the primary pressure boundaries. However, it can be expanded to the system level and include additional equipment, such as instruments, control systems, electrical distribution, and critical utilities. Expanded levels of analyses may improve the payback for the inspection efforts.

A RBI approach can also be made cost-effective by integrating with recent industry initiatives and government regulations, such as API RP 750, *Management of Process Hazards, Process Safety Management* (OSHA 29 CFR 1910.119), or the proposed Environmental Protection Agency *Risk Management Programs for Chemical Accident Release Prevention*.

### 1.3 APPLICATIONS OF RBI

#### 1.3.1 Optimization Procedures

When the risk associated with individual equipment items is determined and the relative effectiveness of different inspection techniques in reducing risk is quantified, adequate information is available for developing an optimization tool for planning and implementing a risk-based inspection.

Figure 1-1 presents stylized curves showing the reduction in risk that can be expected when the degree and frequency of inspection are increased. Where there is no inspection, there may be a higher level of risk. With an initial investment in inspection activities, risk drops at a steep rate. A point is reached where additional inspection activity begins to show a diminishing return and, eventually, may produce very little additional risk reduction.

Not all inspection programs are equally effective in detecting in-service deterioration and reducing risks, however. Various inspection techniques are usually available to detect any given damage mechanism, and each method will have a different cost and effectiveness. The upper curve in Figure 1-1 represents a typical inspection program. A reduction in risk is achieved, but not at optimum efficiency. Until now, no cost-effective method has been available to determine the combination of inspection methods and frequencies that are represented on the lower curve in Figure 1-1.

RBI provides a methodology for determining the optimum combination of methods and frequencies. Each available inspection method can be analyzed and its relative effectiveness in reducing failure frequency estimated. Given this information and the cost of each procedure, an optimization program can be developed. Similar programs are available for optimizing inspection efforts in other fields.

The key to developing such a procedure is the ability to quantify the risk associated with each item of equipment and then to determine the most appropriate inspection techniques for that piece of equipment.

Increased inspection reduces risk through a reduction in future failure frequencies by corrective and preventative measures taken after the inspection has identified problem areas. Inspection does not alter consequences, which are the other component of risk. Consequences are changed through design changes or other corrective actions. However, the RBI methodology can identify areas where consequences of possible failure events can be reduced by system changes or mitigation procedures.

As shown in Figure 1-1, risk cannot be reduced to zero solely by inspection efforts. The uninspectable factors for loss of containment include, but are not limited to, the following:

- a. Human error.
- b. Natural disasters.
- c. External events (e.g., collisions or falling objects).
- d. Secondary effects from nearby units.
- e. Deliberate acts (e.g., sabotage).
- f. Fundamental limitations of the inspection method.
- g. Design errors.
- h. Previous unknown mechanisms of deterioration.

Many of these factors are strongly influenced by the Process Safety Management (PSM) system in place at the facility. As described in Section 1.9.2, a RBI program can also consider the effectiveness of the management systems.

### 1.3.2 Database Improvements

The accuracy and utility of risk studies could be improved if process-specific failure data were available. Initial efforts by the process industry to develop such databases include the following:

- a. A consortium of offshore exploration and production companies operating in the North Sea has been supporting the Offshore Reliability Database (OREDA), an equipment reliability database, for more than a decade.
- b. The UK Operators Exploration and Production Forum initiated a Hydrocarbon Leak and Ignition Database in 1993, with the goal of creating a source of high quality leak and ignition data to be used in offshore risk assessments.
- c. The American Institute of Chemical Engineers Center for Chemical Process Safety has initiated a pilot project, with the goal of assessing existing data and data collection systems, in an effort to support an industry-wide equipment reliability database patterned after OREDA.

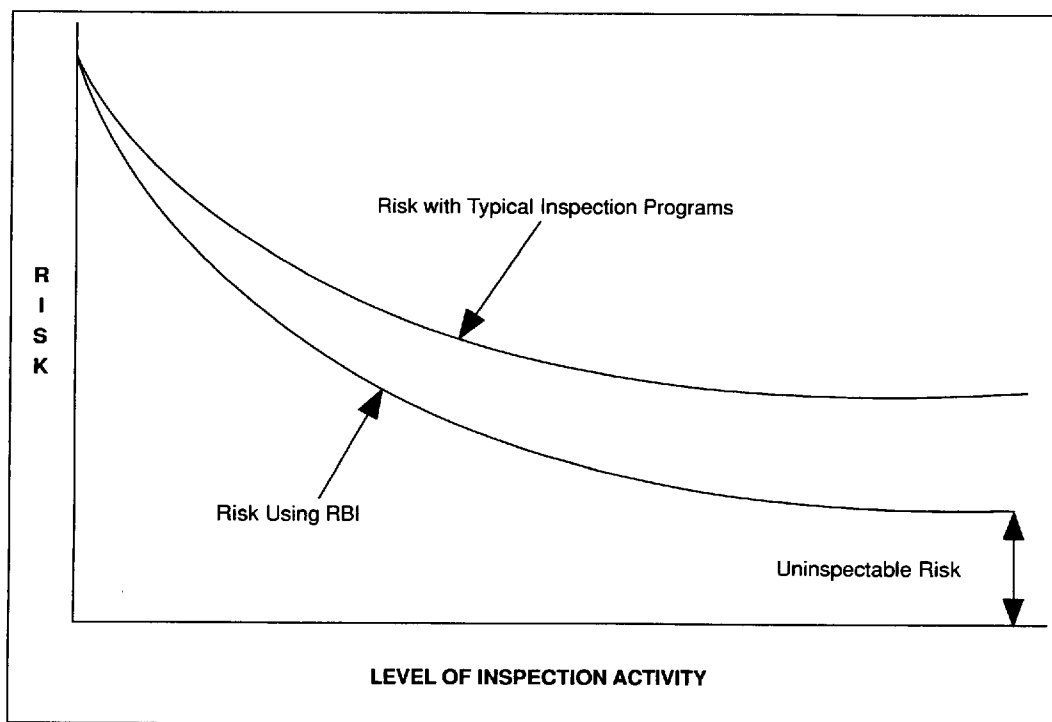


Figure 1-1—Management of Risk Using RBI

d. The Materials Properties Council has proposed a program to quantify failure histories for the specific problem of low-temperature brittle failure potential as a result of auto-refrigeration of light liquid hydrocarbons.

e. A future phase of this American Petroleum Institute Project on Risk-Based Inspection is under consideration that is intended to establish an equipment failure database to support, with high quality data, the methodology described in this BRD.

Additional references to use as starting points for process specific failure data include:

- *What Went Wrong*, T. A. Kletz, Gulf Publishing Co., Houston, TX, 1986.
- *Handbook of Case Histories in Failure Analysis*, ASM International, Materials Park, OH, 1992.
- *Safety Digest of Lessons Learned*, Sections 1 through 6, American Petroleum Institute, Washington, D.C., 1982.
- *Understanding How Components Fail*, D. J. Wulpi, ASM International, Materials Park, OH, 1987.
- *Defects and Failures in Pressure Vessels and Piping*, H. Thielsch, Krieger Publishing Co., Malabar, FL, 1977.

Risk-Based Inspection should incorporate process-specific failure data when they become available, either from industry groups or internally within a company.

### 1.3.3 Other Uses For RBI

Table 1-1 shows how the risk of loss of containment relates to the various categories that may contribute to a failure. Loss of containment occurs only when the pressure boundary is breached. As the figure demonstrates, however, failure of any of the equipment categories or human factors can act as a precursor to the failure of the pressure boundary. A power failure or an instrument malfunction can result in a process upset. If appropriate action is not taken by the process operator, conditions can be reached that will result in a breach or failure of the pressure envelope. It follows, therefore, that damage prevention efforts should be coordinated across all these areas.

This integrated approach will require a significant paradigm shift within the process industry. First, priorities will be based on risk, rather than just on the likelihood of failure that drives many inspection decisions today. Second, organizational approaches will need re-examination. Current practice usually assigns maintenance and inspection responsibility by the category of equipment: electrical, instrumentation and controls, fixed equipment, and rotating equipment. Environmental, safety, risk, and process responsibilities also are typically assigned to dedicated groups, each in a different part of the organization and different from those responsible for equipment performance. Some companies have begun to organize into Technology Teams, where people with these specialist backgrounds can focus their efforts on continuously improving the reliability of the process. Risk-Based Inspection, in its broadest sense, could

become a platform to integrate, direct, and measure the activities of these specialists.

The output from a RBI analysis can also be useful in risk reduction efforts outside inspection planning. Traditional inspection activities may be driven by the likelihood-of-failure part of the risk equation, rather than the consequence of failure. Risks of high consequence can be reduced by improved isolation capability or other mitigation procedures. The output of a RBI analysis, when sorted by consequence can provide a prioritized list for such efforts.

## 1.4 DEFINING AND MEASURING RISK

The RBI system defines risk as the product of two separate terms—the *likelihood* that a failure will occur and the *consequence of a failure*. Understanding the two-dimensional aspect of risk allows new insight into the use of risk as an inspection prioritization tool.

Figure 1-2 displays the risk associated with the operation of a number of equipment items in a process plant. Both the likelihood and consequence of failure have been determined for ten equipment items, and the results have been plotted. The points represent the risk associated with each equipment item. Ordering by risk produces a risk-based ranking of the equipment items to be inspected. From this list, an inspection plan can be developed that focuses attention on the areas of highest risk.

## 1.5 THE RELATIONSHIP BETWEEN INSPECTION AND RISK

Given that the “risk” of an accident has two components, likelihood and consequence, inspection, an activity intended to limit risk must reduce one or both of the risk components. We gain substantial insight into the relationship between inspection and risk by recognizing which component of risk a particular inspection activity is intended to reduce. An analogy helps to clarify this concept.

One of the greatest risks people face in modern society is the risk of injury or death in an automobile accident. People accept that risk individually, but collectively our society tries to control that risk. Obvious examples of control are limits on driver age, training and testing of drivers, prohibition of driving under the influence of alcohol, placing limits on speed, and enforcing other laws and regulations. Another action society has taken is to require an inspection of all automobiles on a yearly basis. This action seems important intuitively, but what effect does it have? Does it affect the likelihood of accidents, the consequences, or both? Table 1-2 indicates some possible conclusions by examining the components of the vehicle inspection.

The effect of inspecting any specific component on likelihood or consequence could be argued, but most people would agree that these inspections are important. For our personal safety, we keep our cars in good condition. Although state

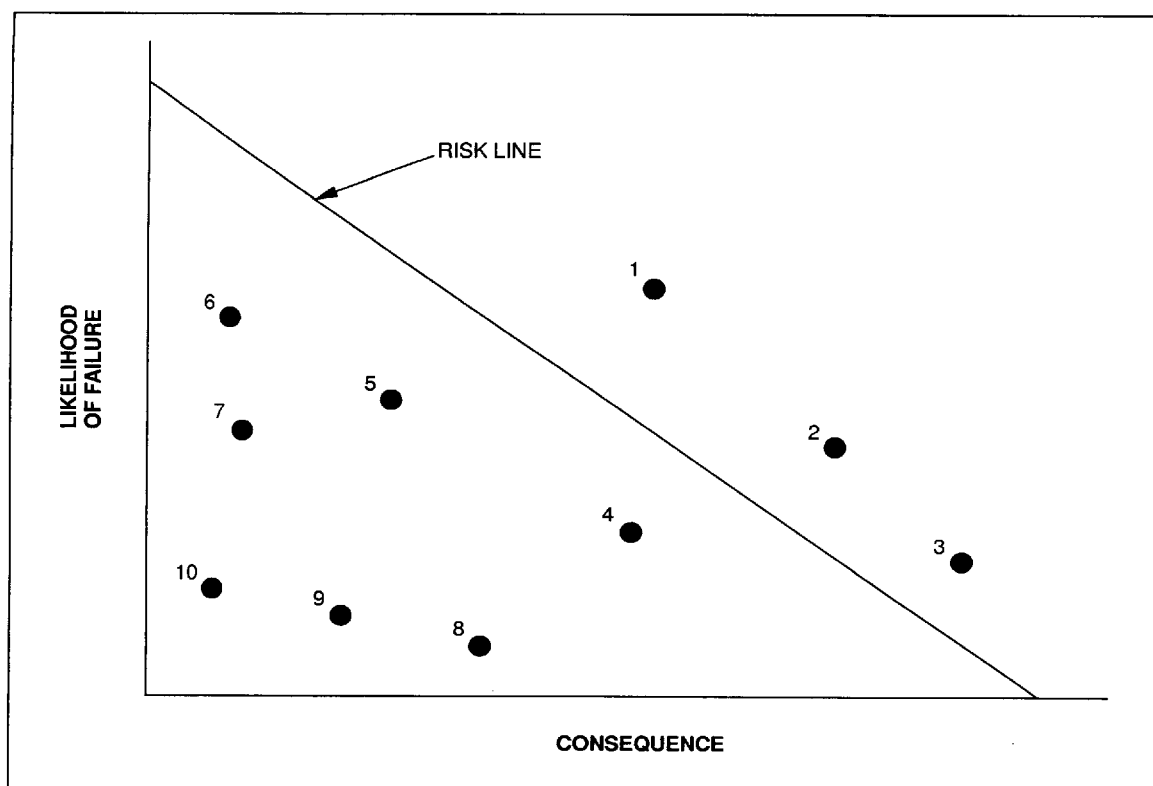


Figure 1-2—Risk Line

Table 1-1—Basic Elements in Loss of Containment

| Category                | Precursor | Loss of Containment |
|-------------------------|-----------|---------------------|
| Pressure Boundary       | X         | X                   |
| Mechanical Equipment    | X         |                     |
| Electrical Equipment    | X         |                     |
| Instrument and Controls | X         |                     |
| Safety Systems          | X         |                     |
| Human Factors           | X         |                     |

Table 1-2—Components of Vehicle Inspection

| Component    | Likelihood | Consequence |
|--------------|------------|-------------|
| Horn         | X          |             |
| Headlights   | X          |             |
| Turn Signals | X          |             |
| Brakes       | X          | X           |
| Wipers       | X          |             |
| Tires        | X          | X           |
| Seat Belts   |            | X           |

inspection can be a nuisance, few would vote to eliminate them; we want the “other guy” to maintain his car to our high standards. Why? It reduces our risk!

In this analogy, all of the inspections except one are *function inspections*; the exception is a *condition inspection*. Functional inspections, such as for the horn, are pass/fail. If the horn works, it passes the inspection. The exception is the inspection of the car’s tires. If a car is driven to the inspection station, the tires are filled with air and are functioning properly. However, the pass/fail criterion in this case is not the function, but the condition of the tires. If the tread wear exceeds a certain limit, the tires do not pass the inspection. There are many ways to test the function of a component and many ways to test the condition. Some tests may do both. The important point is that the test used must be appropriate to the desired result. Checking the tires’ pressure to see if they have air in them would be as meaningless as visually examining the horn to see if it works.

The above analogy illustrates that inspection can affect risk. When inspection is expanded to a process plant, however, the issue becomes increasingly complicated. For one thing, an entire vehicle can be safety inspected in a few minutes, whereas a thorough inspection of a single component in a process plant can easily take several days. When we



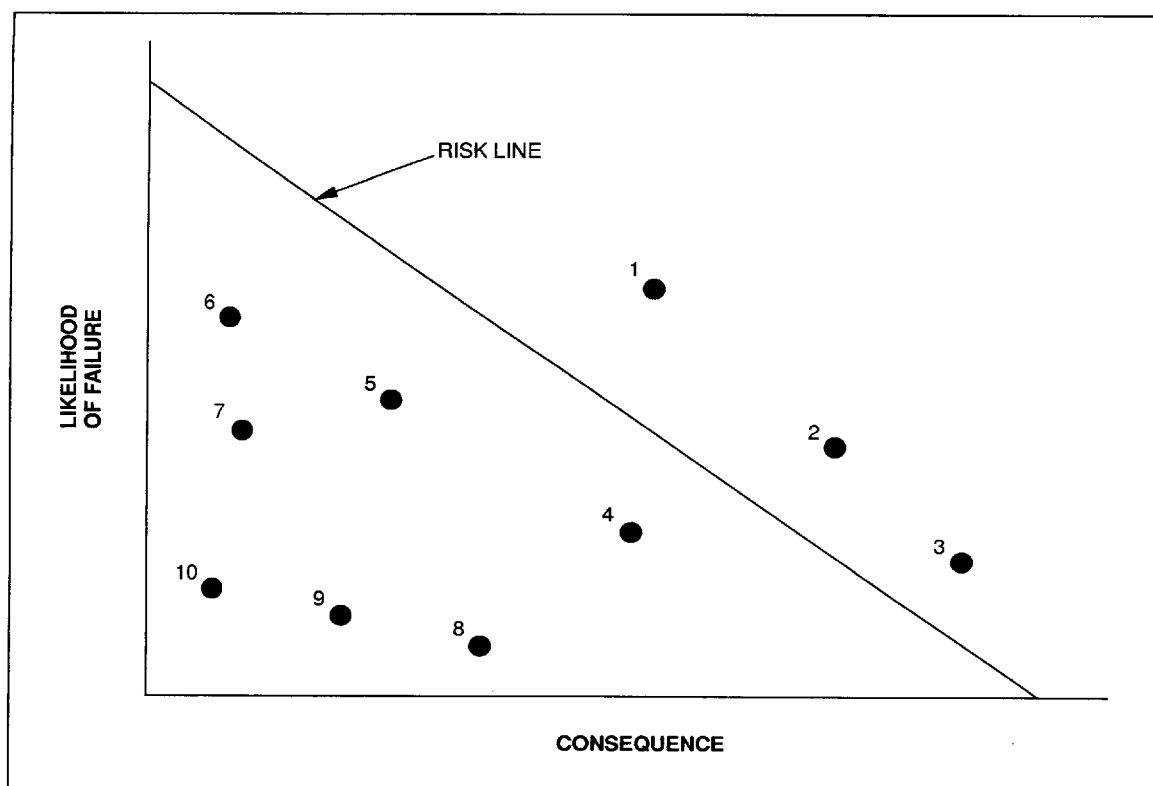


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The above analogy illustrates that inspection can affect risk. When inspection is expanded to a process plant, however, the issue becomes increasingly complicated. For one thing, an entire vehicle can be safety inspected in a few minutes, whereas a thorough inspection of a single component in a process plant can easily take several days. When we

consider the number of components to be inspected, and the number of appropriate ways of inspecting them, the task of setting priorities can appear very significant.

## 1.6 CURRENT INSPECTION PRACTICES

In process plants, inspection and testing programs are established to detect and evaluate deterioration and damage due to in-service operation. The effectiveness of inspection programs varies widely, however. At one end of the scale are the reactive programs, which concentrate on known areas of concern, in contrast to a broad program covering a variety of equipment. The extreme of this would be the "don't fix it unless it's broken" approach.

Somewhere in the middle of the inspection-effectiveness scale is the approach that conducts inspections on a scheduled basis, but with a limited variety of inspection methods, perhaps ultrasonic thickness (UT) measurement or radiography.

The most comprehensive inspection programs are designed to meet the intent of API and other inspection standards by identifying the in-service deterioration modes and designing an inspection program for detecting specific defects. These programs are based on an understanding of all potential damage mechanisms in each equipment item.

The most comprehensive testing methods can be very costly, without being cost effective. RBI has the potential to reduce these costs in a way that will still provide a system of prioritizing inspections so they will fully address safety concerns. A risk-based ranking of all equipment items provides the basis for allocating inspection efforts so that potentially high-risk areas can receive sophisticated and frequent inspections, while low-risk areas are inspected in a manner commensurate with the lower risk.

### 1.6.1 Technical Basis

In general, pressure envelope deterioration and damage can be classified into eight very broad damage types:

- a. Thinning.
- b. Metallurgical changes.
- c. Surface connected cracking.
- d. Dimensional changes.
- e. Subsurface cracking.
- f. Blistering.
- g. Micro fissuring/microvoid formation.
- h. Material properties changes.
- i. Positive Material Identification (PMI).

Understanding the types of damage can help the inspector select the appropriate inspection method and location for a particular application.

The existing API Inspection Standards (API 510, *Pressure Vessel Inspection Code*; API 570, *Piping Inspection Code*; and API 653, *Tank Inspection, Repair, Alteration, and*

*Reconstruction*) represent the body of accepted inspection practices for pressure boundary equipment. The RBI procedures presented in this Base Resource Document draw on these API Standards and other industry practices to identify potential problem areas and quantify the relative severity of the concerns.

API inspection standards have established rules for setting minimum inspection frequencies in situations where the damage mechanism is loss of material. Long intervals are permitted if the service is non-corrosive. However, the standards provide only limited guidance for setting inspection frequencies for cracking and for situations where material properties are changing.

As RBI procedures and fitness-for-service (FFS) guidelines are incorporated into API standards, the concept of measuring and managing risk will become a key part of inspection planning.

### 1.6.2 Frequency of Inspection

Fitness-for-service procedures can be used to set inspection intervals for cracking or changing material properties. The actual rate of deterioration is a function of a complex interaction of material properties, process environment, operating conditions, and state of stress. In the FFS procedure, a conservative estimate of the deterioration rate is calculated. The amount of damage that the component can withstand is then calculated, and the next inspection is scheduled well before the anticipated failure. With each future inspection, the actual deterioration rate is better defined, and inspection frequencies can be adjusted accordingly.

### 1.6.3 Linking RBI to Inspection Standards

An even more direct link than the one to fitness-for-service procedures exists between RBI and the large body of information that defines today's inspection practices. Made up of working documents such as API 510, API Std 653, and API 570, these inspection practices are deeply imbedded in the RBI prioritization procedure. Codes and standards from API, ASME, and other organizations have been used whenever possible in the screening and evaluation procedures and in establishing the factors used to modify generic failure frequency values. Where definitive standards have not yet been established, industry experience and good practices have provided the basis for evaluation.

When API issues the Recommended Practice (RP 580) for *Risk-Based Inspection*, it too will become part of this broad body of information. This "full loop" concept is illustrated in Figure 1-3. With the RBI RP in place, inspections will continue to be conducted as defined in existing working documents, but priorities and frequencies will be guided by the RBI procedure.

### 1.6.4 Relationship to Other Existing and Developing API Documents

Figure 1-3 illustrates the interaction between RBI and other existing and developing API documents. API RP 750, *Management of Process Hazards*, provides a comprehensive definition of an effective process safety management system. Among other things, it requires use of process hazard analyses, compilation of mechanical and operating records and procedures, and implementation of an effective equipment inspection program. RP 750 is shown as the umbrella policy under which existing inspection codes operate and new procedures are being developed.

The relationship between RBI and other developing procedures is illustrated by the interaction between the Base Resource Document (BRD) and the Material Properties Council (MPC). API and MPC are nearing completion of API Recommended Practice 579, *Fitness-For-Service*. This and other developing procedures will also be integrated into existing procedures, where appropriate.

### 1.7 A RISK-BASED INSPECTION SYSTEM

A fully integrated Risk-Based Inspection system should contain the steps shown in Figure 1-4. The system includes inspection activities, inspection data collection, updating, and continuous improvement of the system. Risk analysis is "state of knowledge" specific and, since the processes and systems are changing with time, any risk study can only reflect the situation at the time the data was collected. Although any system when first established may lack some needed data, the risk-based inspection program can be established based on the available information, using conservative assumptions for unknowns. As knowledge is gained from inspection and testing programs and the database improves, uncertainty in the program will be reduced. This results in reduced uncertainty in the calculated risks.

When an inspection identifies equipment flaws, they are evaluated using appropriate engineering analysis or the emerging fitness-for-service methods. Based on this analysis, decisions can be made for repairs, maintenance, or continued operation. The knowledge gained from the inspection, engineering evaluation and maintenance is captured and used to update the plant database. The new data will affect the risk calculations and risk ranking for the future. For example, a vessel suspected of operating with stress corrosion cracks could have a relatively high risk ranking. After inspection, repairs, and change or removal of the adverse environment, the risk calculated for the vessel would be significantly lower, moving it down in the risk ranking and allowing the revised risk-based inspection plan to focus on other equipment items.

Figure 1-4 also incorporates a periodic audit of the whole system. With this feature, incorporating the recommendations from the system audit, the risk-based inspection fits into the Quality Improvement Process (QIP) and allows for continuous improvement.

### 1.8 QUALITATIVE AND QUANTITATIVE APPLICATIONS

The RBI procedure can be applied *qualitatively*, *quantitatively* or in combination. Both approaches provide a systematic way to screen for risk, identify areas of potential concern, and develop a prioritized list for more in-depth inspection or analysis. Both develop a risk ranking measure to be used for evaluating separately the probability of failure and the potential consequence of failure. These two values are then combined to estimate risk.

The primary difference between the qualitative and quantitative approach is the level of resolution. The qualitative procedure requires less detailed information about the facility and, consequently, its ability to discriminate is much more limited. The qualitative technique would normally be used to rank units or major portions of units at a plant site to determine priorities for quantitative RBI studies or similar activities.

A quantitative RBI analysis, on the other hand, will provide risk values for each equipment item and pipe segment. With this level of information, a comprehensive inspection plan can be developed for the unit.

### 1.9 THE INTERACTION BETWEEN RBI AND OTHER SAFETY INITIATIVES

The Risk-Based Inspection methodology has been designed to interact with other safety initiatives wherever possible. The output from several of these initiatives provides input for a variety of RBI evaluations and, in some instances, the RBI risk rankings can be used to improve other safety systems. Some examples are given below.

#### 1.9.1 Process Hazard Analysis

A Process Hazard Analysis (PHA) uses a systematized approach to identify and analyze hazards in a process unit. The RBI study can include a review of the output from any PHAs that have been conducted on the unit being evaluated. Hazards identified in the PHA can be specifically addressed in the RBI analysis.

Potential hazards identified in a PHA would often impact the probability-of-failure side of the risk equation. The hazard may result from a series of events that could cause a process upset, or it could be the result of process or instrumentation deficiencies. In either case, the hazard might increase the probability of failure, in which case the RBI procedure would reflect the same.

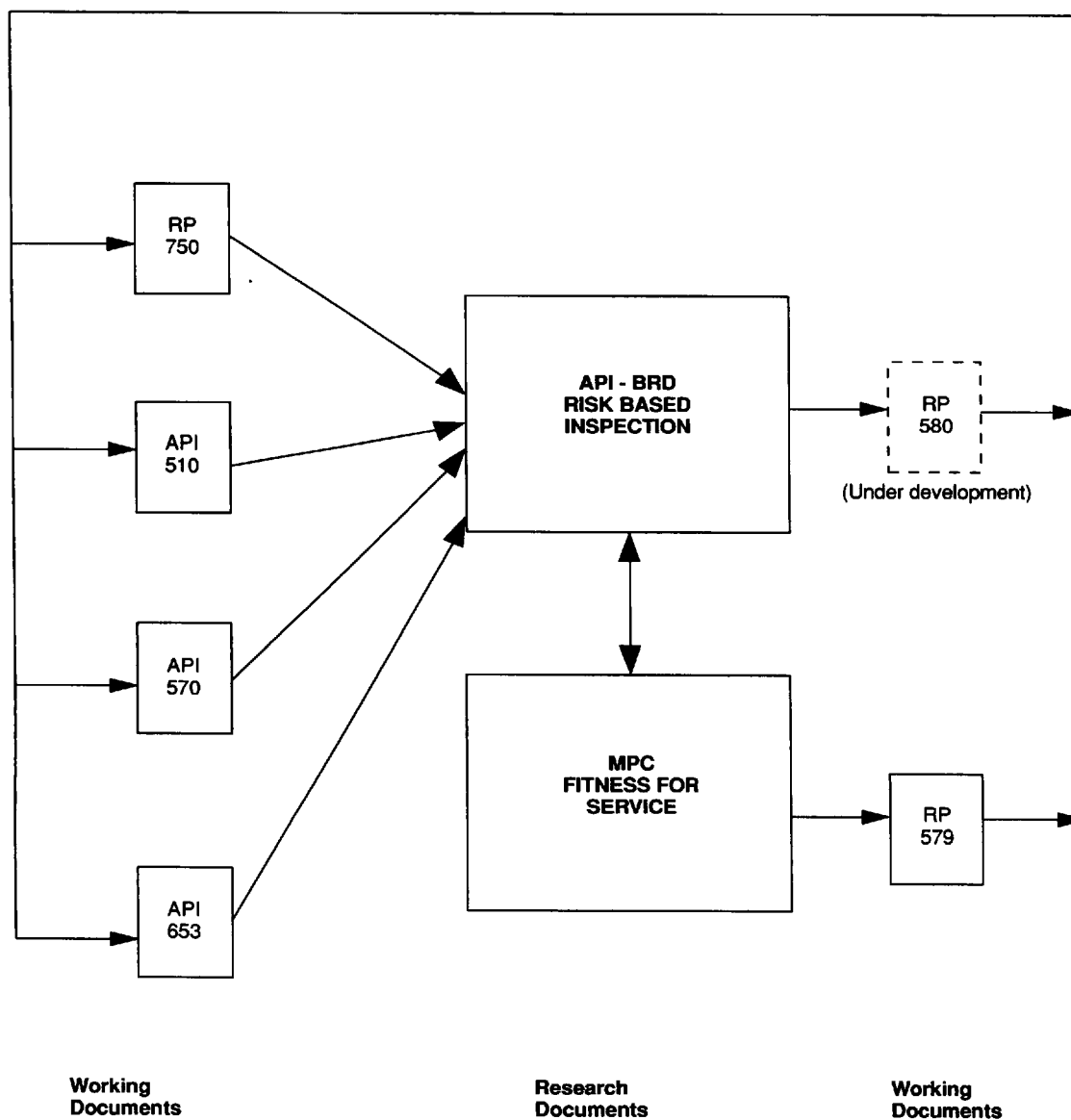


Figure 1-3—Relationship Between Existing and Developing Documents

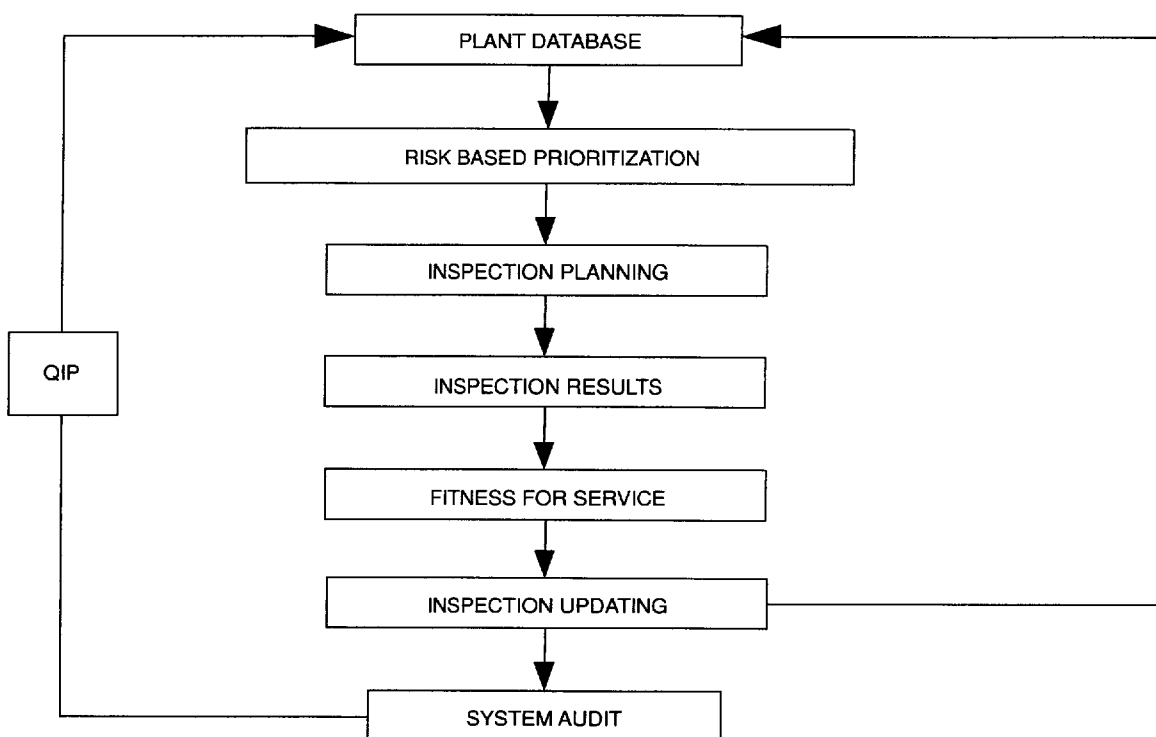


Figure 1-4—Risk-Based Inspection Program for In-Service Equipment

Some hazards identified would affect the consequence side of the risk equation. For example, the potential failure of an isolation valve could increase the inventory available for release in the event of a leak. The consequence calculation in the RBI procedure can be modified to reflect this added hazard.

The plant layout and construction might be evaluated to see if it has the following characteristics:

- Equipment spacing and orientation that facilitates maintenance and inspection activities and minimizes the amount of damage in case of a fire or explosion.
- Control rooms and other operator stations that are located and constructed in a manner to provide proper shelter in case of a fire or explosion.
- Appropriate attention has been given to leak detection, fire water systems, and other emergency equipment.

### 1.9.2 Process Safety Management

A strong Process Safety Management system of the kind described in API RP 750 can significantly reduce the risk in a process plant. Section 8.4 and the Workbook in Appendix C include methodology to assess the effectiveness of the man-

agement systems in maintaining the mechanical integrity of the unit being evaluated. The results of the management systems evaluation are factored into the risk determinations.

Several of the features of a good PSM program provide input for a RBI study. Extensive data on the equipment and the process are required in the RBI analysis, and output from PHA's and incident investigation reports increases the validity of the study. In turn, the RBI procedures can improve the PSM program. An effective PSM program must include a well-structured equipment inspection program. The RBI system will improve the focus of the inspection plan, resulting in a strengthened PSM program.

Operating with a comprehensive inspection program should reduce the risks of releases from a facility and should provide benefits in complying with safety-related initiatives.

### 1.9.3 Equipment Reliability

Equipment reliability programs can provide input to the probability analysis portion of a RBI program. Specifically, reliability records can be used to develop equipment failure probabilities and leak frequencies. Equipment reliability is

especially important if leaks can be caused by secondary failures, such as loss of utilities.

Future work might link reliability efforts such as Reliability Centered Maintenance (RCM) with RBI, resulting in an integrated program to reduce downtime in an operating unit.

#### **1.9.4 Traditional Quantitative Risk Assessment**

Quantitative Risk Assessment (QRA) refers to the prescriptive methodology that has resulted from the application of risk analysis techniques at petrochemical process facilities. For all intents and purposes, it is a traditional risk analysis. Because RBI takes some of its parentage from traditional risk

analysis, the QRA shares many of the data requirements of a RBI. If a QRA has been prepared for a process unit, the RBI program can borrow extensively from this effort. Information common to both a QRA and a RBI program is as follows:

- a. Generic data.
- b. Population information.
- c. Ignition sources.
- d. Meteorological data.
- e. Dispersion distances.
- f. Conditional probabilities for fate of vapor cloud.

Section 4 presents a more detailed discussion of QRA and compares RBI with a traditional risk analysis.

## Section 2—References and Bibliography

### 2.1 REFERENCES

Unless specified otherwise, the most recent editions or revisions of the following standards, codes, and specifications shall, to the extent specified herein, form a part of this publication.

#### API

- Std. 510 *Pressure Vessel Inspection Code: Maintenance, Inspection, Rating, Repair, and Alteration*
- Std. 570 *Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems*
- Std. 653 *Tank Inspection, Repair, Alteration and Reconstruction*
- RP 521 *Guide for Pressure-Relieving and Depressuring Systems*
- RP 530 *Calculation of Heater Tube Thickness in Petroleum Refineries*
- RP 579 *Fitness-for-Service*
- RP 941 *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*
- 750 *Management of Process Hazards*

#### AICHE/CCPS<sup>1</sup>

- Guidelines for Chemical Process Quantitative Risk Analysis*
- Guidelines for Hazard Evaluation Procedures*
- Guidelines for Use of Vapor Cloud Dispersion Models*

#### ASME<sup>2</sup>

- Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels," Division 1; Section IX, "Welding and Brazing Qualifications"*

#### EPA<sup>3</sup>

- Risk Management Programs for Chemical Accident Release Prevention, 40 CFR Part 68, Proposed Rule, Docket A-91-73*

#### NFPA<sup>4</sup>

- Fire Protection Guide to Hazardous Materials, 10th Edition, 1991*

<sup>1</sup>American Institute of Chemical Engineers/Center for Chemical Process Safety, 345 East 47th Street, New York 10017.

<sup>2</sup>ASME International, 3 Park Avenue, New York, New York 10016.

<sup>3</sup>U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20406.

<sup>4</sup>National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02269.

#### OSHA<sup>5</sup>

*Process Safety Management of Highly Hazardous Chemicals Standard, Title 29, Code of Federal Regulations (CFR) Part 1910.119 (FR57(36); 6356-6417*

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## Section 3—Definitions

For the purposes of this publication the following definitions apply:

**3.1 affected area:** Represents the amount of surface area that experiences an effect (toxic dose, thermal radiation, explosion overpressure, etc.) greater than a pre-defined limiting value.

**3.2 auto-ignition factor (AF):** Accounts for the increased probability of ignition for a fluid released at a temperature above its auto-ignition temperature.

**3.3 auto-ignition temperature:** Temperature for which a material can ignite without a source of ignition.

**3.4 average individual risk:** A similar concept to the Fatal Accident Rate, but with a time period of one year.

**3.5 average rate of death:** The average number of fatalities from all incidents that might be expected per unit time.

**3.6 Bayes' theorem:** A statistical method which can effectively relate an uncertain inspection result with prior to the inspection "expectations" and provide an increased level of confidence on the equipment damage rate predictions.

**3.7 business interruption (financial risk):** Includes the costs which are associated with any failure of equipment in a process plant. These include, but are not limited to: cost of equipment repair and replacement; downtime associated with equipment repair and replacement; costs due to potential injuries associated with a failure; and environmental cleanup costs.

**3.8 chemical factor (CF):** A combination of a chemical material's Flash Factor and its Reactivity Factor. Flash Factors correspond to the material's NFPA Class rating; the Reactivity Factor is a function of how readily the material can explode when exposed to an ignition source.

**3.9 cold weather operation:** The additional risks imposed on plant operations by cold climates, as they inhibit maintenance and inspection activities and can result in reduced operator monitoring of outside equipment.

**3.10 condition factor (CCF):** The physical condition of the equipment from a maintenance and housekeeping perspective.

**3.11 consequence:** The outcome of an event or situation expressed qualitatively or quantitatively, being a loss, injury, disadvantage or gain.

**3.12 consequence analysis:** performed to aid in establishing a relative ranking of equipment items on the basis of risk.

**3.13 consequence area:** Reflects the area within which the results of an equipment failure will be evident.

**3.14 consequence category:** See Damage Consequence Category, Chemical Factor, Quantity Factor, State Factor, Auto-Ignition Factor, Pressure Factor, Credit Factor.

**3.15 consequence modeling:** Prediction of failure consequences based on a set of empirical equations, using release rate (for continuous releases) or mass (for instantaneous releases) as input.

**3.16 continuous release:** One that occurs over a longer period of time, allowing the fluid to disperse in the shape of an elongated ellipse.

**3.17 corrosion, general:** Refers to corrosion dominated by uniform thinning that proceeds without appreciable localized attack.

**3.18 corrosion, localized:** Describes different forms of corrosion, all of which have the common feature that the corrosion damage produced is localized rather than spread uniformly over the exposed metal surface.

**3.19 cost:** Of activities, both direct and indirect, involving any negative impact, including money, time labor, disruption, goodwill, political and intangible losses.

**3.20 credit factor (CRF):** Accounts for the safety features engineered into the unit.

**3.21 damage consequence factor:** Combination of Chemical Factor, Quantity Factor, State Factor, Auto-Ignition Factor, Pressure Factor, and Credit Factor.

**3.22 damage factor:** A measure of the risk associated with known damage mechanism in the unit; including levels of general corrosion, fatigue cracking, low temperature exposure, and high-temperature degradation.

**3.23 damage mechanism:** Corrosion or mechanical action that produce the equipment damage.

**3.24 damage state:** Classification of equipment based on its condition, level of damage.

**3.25 detection:** System aims to reduce the leak duration.

**3.26 direct effect model:** Uses a pass/fail approach to predict the consequence from a given outcome. See Impact Criteria, Probability Unit.

**3.27 discharge:** Material release due to a failure. It can be either instantaneous in nature or constant.

**3.28 dispersibility factor (DIF):** A measure of the ability of a material to disperse.

**3.29 dispersion:** Vapor cloud will be formed after the release of vapor or volatile liquid in the environment. The vapor cloud is dispersed through mixing with air until the concentration eventually reaches a safe level or is ignited.

**3.30 ductile overload:** Occurs when the flow stress is exceeded by the stress caused by the applied loads.

**3.31 environment:** Area outside a facility's jurisdiction that would require substantial costs to remediate in the event of contamination. It can include groundwater tables that pass through the bounds of the facility and would allow contamination of water external to the facility.

**3.32 environmental consequence:** Acute effects from a spill; also the impact of liquid releases into the environment.

**3.33 environmental effect:**

**3.34 environmental impact:** Criteria for spills to the environment: spills on water, spills above ground, and leaking storage tanks.

**3.35 equipment complexity:** Indicator which differentiates process vessels based on their size and complexity.

**3.35.1 equipment factor:** Number of components in the unit that have the potential to fail.

**3.36 equipment modification factor:** Specific conditions that can have a major influence on the failure frequency of the equipment item. The conditions are categorized into four subfactors. See Technical Module Subfactor, Universal Subfactor, Mechanical Subfactor, and Process Subfactor.

**3.37 event:** An incident or situation, which occurs in a particular place during a particular interval of time.

**3.38 event tree:** Visually depict the possible chain of events that lead to the probability of flammable outcomes; used to show how various individual event probabilities should be combined to calculate the probability for the chain of events.

**3.39 event tree analysis:** A technique which describes the possible range and sequence of the outcomes which may arise from an initiating event.

**3.40 explosion:** Occurs under certain conditions when a flame front travels very quickly.

**3.41 failure mode and effects analysis (FMEA):** An inductive analysis that systematically details, on the component level, all possible failure modes and identifies their resulting effects on the system. The technique is most effective at identifying single-point failures in a system.

**3.42 fatal accident rate (FAR):** Estimated number of fatalities per 108 exposure hours (roughly 1000 employee working lifetimes).

**3.43 fault tree analysis:** A deductive approach to hazard identification that focuses on the causes of an undesired event.

**3.44 fireball:** Occurs when a large quantity of fuel ignites after it has undergone only limited mixing with the surrounding air.

**3.45 flammability range:** Difference between upper and lower flammability limits.

**3.46 flammable consequence:** Result of the release of a flammable liquid in the environment.

**3.47 flammable effect:** Physical behavior of the hazardous material that is released. See Safe Dispersion, Jet Flame, Explosion, Flash Fire, Fireball, and Pool Fire.

**3.48 flash fire:** Occurs when a cloud of material burns under conditions that do not generate significant overpressure.

**3.49 flash temperature:** Temperature for which a material can ignite given a source of ignition.

**3.50 fluid phase:** Defined as either gas or liquid.

**3.51 frequency:** A measure of likelihood expressed as the number of occurrences of an event in a given time. See also Likelihood and Probability.

**3.52 gas release rate:** Is calculated in a two-step process. The first step determines which gas flow regime is present (sonic for higher internal pressures, subsonic for lower pressures). The second step estimates the release rate using the equation for the specific flow regime.

**3.53 generic failure frequency:** A compilation of available records of equipment failure histories, developed for each type of equipment and each diameter of piping; built using records from all plants within a company or from various plants within an industry, from literature sources, past reports, and commercial data bases. The values represent an industry in general and do not reflect the true failure frequencies for a specific plant or unit.

**3.54 hazard:** A source of potential harm or a situation with a potential to cause loss.

**3.55 hazard and operability study (HAZOP):** A structured brainstorming exercise that utilizes a list of guidewords to stimulate team discussions. The guidewords focus on process parameters, such as flow, level, temperature, and pressure, and then branch out to include other concerns, such as human factors, and operating outside normal parameters.

**3.56 health consequence category:** Combination of Toxic Quantity Factor, Dispersibility Factor, Credit Factor, and Population Factor.

**3.57 IDLH value:** Immediately Dangerous to Life or Health value.

**3.58 impact criteria:** Used to estimate consequences from an outcome; also known as effect models. See Direct Effect Model, Probability Unit.

**3.59 individual risk measures:** Consider the risk to an individual who might be located at any point in the effect zones of incidents.

**3.60 inspection effectiveness:** Is qualitatively evaluated by assigning the inspection methods to one of five descriptive categories ranging from Highly effective to Ineffective.

**3.61 inspection factor:** A measure of the effectiveness of the current inspection program and its ability to identify the active or anticipated damage mechanisms in the unit.

**3.62 instantaneous release:** One that occurs so rapidly that the fluid disperses as a single large cloud or pool.

**3.63 inventory:** Upper limit of the amount of fluid that can be released from an equipment item.

**3.64 inventory group:** Inventory of attached equipment that can realistically contribute fluid mass to a leaking equipment item.

**3.65 isolation:** Use of isolation systems results in reduction of leak duration time.

**3.66 jet flame:** Results when a high-momentum gas, liquid, or two-phase release is ignited.

**3.67 life cycle of equipment:** Is an indicator which is based on the design life of the equipment item and on the number of years that the item has been in its current service.

**3.68 likelihood:** Used as a qualitative description of probability and frequency.

**3.69 likelihood analysis:** A database of generic failure frequencies for onshore refining and chemical processing equipment; which is then modified by the Equipment Modification Factor and the Management Systems Evaluation Factor. See Generic Failure Frequency, Equipment Modification Factor and Management Systems Evaluation Factor.

**3.70 likelihood category:** Assigned by evaluating the six factors that affect the likelihood of a large leak. Each factor is weighted and their combination results in the Likelihood Factor. See Equipment Factor, Damage Factor, Inspection Factor, Condition Factor, Process Factor, and Mechanical Design Factor.

**3.71 limit state function:** Defines a mode of failure,  $g(Z_i)$ , where  $Z_i$  are random variables associated with the failure of process equipment. Probability of failure is the probability of being in the failure set,  $g(Z_i) < 0$ .

**3.72 loss:** Any negative consequence, financial or otherwise.

**3.73 loss of containment:** Occurs only when the pressure boundary is breached.

**3.74 management systems evaluation:** An evaluation of all areas of a plant's Process Safety Management's system that impact directly or indirectly on the mechanical integrity of process equipment.

**3.75 management systems evaluation factor:** Adjusts the generic failure frequencies for differences in Process Safety Management systems. The factor is derived from the results of an evaluation of a facility or operating unit's management systems that affect plant risk.

**3.76 mechanical design factor:** Measures the safety factor within the design of the unit, whether it is designed to current standards, and how unique, complex or innovative the unit design is.

**3.77 mechanical subfactor:** Addresses conditions related primarily to the design and fabrication of the equipment item, such as complexity, construction code, life cycle, safety factors and vibration monitoring.

**3.78 mitigation systems:** Are designed to detect, isolate and reduce the effects of a release of hazardous materials.

**3.79 monitor:** To check, supervise, observe critically, or record the progress of an activity, action or system on a regular basis in order to identify change.

**3.80 NBP:** Normal Boiling Point.

**3.81 NFPA flammability index:** National Fire Protection Agency Flammability Index.

**3.82 operational boundaries:** Both the normal operation and periods of non-routine operation (startups, shutdowns, process upsets, etc.) of the system being studied.

**3.83 phase of dispersion:** "Final state gas" or "Final state liquid."

**3.84 PHAST:** Process Hazards Analysts Screening Tool, an integrated software package containing atmospheric dispersion and consequence modeling routines.

**3.85 physical boundaries:** All equipment items that make up the pressure envelope of the system being studied.

**3.86 piping complexity:** Comprised of the number of connections, number of injection points, number of branches, and number of valves of a piping segment.

**3.87 plant condition:** Current condition of the facility being evaluated, based on general appearance of the plant, effectiveness of the plant's maintenance program and the plant layout and construction.

- 3.88 pool fire:** Caused when liquid pools of flammable materials ignite.
- 3.89 population factor (PPF):** A measure of the number of people that can potentially be affected by a toxic release event.
- 3.90 post-leak response systems:** Mitigation systems that are designed to detect, isolate and reduce the effects of a release of hazardous materials.
- 3.91 pressure factor (PRF):** A measure of how quickly the fluid can escape.
- 3.92 primary containment:** Refers to all pieces of equipment which contain process materials.
- 3.93 probability:** Likelihood of a specific outcome, measured by the ratio of specific outcomes to the total number of possible outcomes. Probability is expressed as a number between 0 and 1, with 0 indicating an impossible outcome and 1 indicating an outcome is certain.
- 3.94 probability unit (probit):** A statistical method of assessing a consequence. See Impact Criteria, Direct Effect Model.
- 3.95 process factor (PF):** A measure of the potential for abnormal operations or upset conditions to initiate a sequence leading to a loss of containment. It is a function of the number of shutdowns or process interruptions (planned or unplanned), the stability of the process, and the potential for failure of protective devices because of plugging or other causes.
- 3.96 process subfactor:** A numeric value assigned to the conditions that are most influenced by the process (continuity and stability) and how the facility is operated.
- 3.97 qualitative risk based inspection:** Provides a broad-based risk assessment of an operating unit or a part of an operating unit. A qualitative inspection requires less detailed information about the facility and, as a result, its ability to discriminate is much more limited.
- 3.98 quantitative inspection:** Provides risk values for each equipment item and pipe segment in a unit. With this level of information, a comprehensive inspection plan can be developed for the unit.
- 3.99 quantitative risk assessment:** Refers to the prescriptive methodology that has resulted from the application of risk analysis techniques at petrochemical process facilities.
- 3.100 quantity factor (QF):** Largest amount of material that could reasonably be expected to be released from a unit in a single event.
- 3.101 release mass:** Amount of material (in lbs) which will be released during an instantaneous release.
- 3.102 release duration:** Inventory in the system divided by the initial release rate.
- 3.103 release rate:** Is the relatively constant rate of release for a material over a long period of time.
- 3.104 representative fluid:** Represents a process stream mixture in the risk analysis.
- 3.105 risk:** The chance of something happening that will have an impact upon objectives. In Risk-Based Inspection, risk is defined as the product of two separate terms—the likelihood that a failure will occur and the consequence of a failure.
- 3.106 risk acceptance:** An informed decision not to become involved in a risk situation.
- 3.107 risk-based management:** Process of using risk assessment results (including understanding uncertainties) to determine the “best” means of risk reduction.
- 3.108 risk control:** That part of risk management which involves the provision of policies, standards and procedures to eliminate, avoid or minimize adverse risks facing an enterprise.
- 3.109 risk identification:** Process of determining what can happen, why and how.
- 3.110 risk indices:** A single number measure of risk.
- 3.111 risk management:** Systematic application of management policies, procedures and practices to the tasks of identifying, analyzing, assessing, treating and monitoring risk.
- 3.112 safe dispersion:** Occurs when flammable fluid is released and then disperses without ignition.
- 3.113 scenario:** Set of events that can result in an undesirable outcome.
- 3.114 secondary containment:** Mitigation system designed to contain process fluid in case of a release from primary containment equipment.
- 3.115 seismic activity:** Higher probability of failure of a facility located in a seismically active area, even when the plant has been designed to appropriate standards.
- 3.116 societal risk measures:** Consider the risk to groups of people that are in the effect zones of incidents.
- 3.117 state factor (SF):** a measure of how readily a material will flash to a vapor when it is released to the atmosphere.
- 3.118 technical module:** Systematic methods used to assess the effect of specific failure mechanisms on the

probability of failure. It evaluates two categories of information: deterioration rate of the equipment items material of construction, resulting from its operating environment; and the effectiveness of the facility's inspection program to identify and monitor the operative damage mechanisms prior to failure.

**3.119 technical module subfactor (TMSF):** Ratio of the frequency of failure due to damage to the generic failure frequency times the likelihood that the damage level is present.

**3.120 toxic consequence:** Effect of a toxic release.

**3.121 toxic effect:** Toxic consequence.

**3.122 toxic quantity factor (TQF):** A measure of both the quantity and the toxicity of a material. The quantity portion is based on mass; the toxicity is found using the NFPA toxicity factor NH.

**3.123 universal subfactor:** Numeric value assigned to the conditions that equally affect all equipment items in the facility. See Plant Condition, Cold Weather Operations, and Seismic Activity.

**3.124 vibration monitoring element:** Value assigned for monitoring rotating equipment such as pumps and compressors to detect developing problems before equipment failure occurs.

## Section 4—Risk Analysis

### 4.1 FUNDAMENTALS

The RBI program outlined in this Base Resource Document is **not** a full risk analysis. At its core, RBI is a hybrid technique that combines the two disciplines of risk analysis and mechanical integrity. Some of the techniques of RBI are similar to those seen in traditional risk analysis, but the two are not interchangeable. Before implementing a RBI program, one should first have a grasp of some of the fundamentals of a traditional risk analysis. Knowing the fundamentals of a risk analysis will help in understanding the differences between the two techniques. It will also help the user to understand some of the jargon that has been developed by risk analysts.

This section presents an abbreviated review of the major concepts of a traditional risk analysis. Figure 4-1 portrays an overview of the traditional risk analysis process. In its elemental form, a risk analysis is comprised of five tasks:

- a. System definition.
- b. Hazard identification.
- c. Probability assessment.
- d. Consequence analysis.
- e. Risk results.

Some of the phases of a risk analysis are treated differently in a RBI program. For example, while hazard identification is a critical step in a traditional risk analysis, the RBI program focuses on the pressure boundary of a unit, and it assumes that failures are due to identifiable mechanisms of degradation in that boundary. Secondary causes of a leak, such as instrument failures or human errors, are included implicitly in the RBI program's treatment of management systems, while a traditional risk analysis would account for these failures in explicit terms.

The major focus of a traditional risk analysis is to evaluate a variety of scenarios that may lead to undesirable outcomes. Both the likelihood and the magnitude of these outcomes are estimated and displayed as results.

In a risk analysis, a scenario represents the set of events that can result in an undesirable outcome. Figure 4-2 presents the order of events in a typical risk analysis scenario:

- a. Loss of containment.
- b. Detection.
- c. Isolation.
- d. Mitigation.

Depending on the nature of the process and the detail of the study, a risk analysis may include thousands of different scenarios, similar to the one shown here. The risk analysis would evaluate both the likelihood and the consequence of the set of events in each scenario. For RBI, likelihood and consequence are also evaluated, but for a carefully defined and limited number of scenarios.

### 4.2 SYSTEM DEFINITION FOR A TRADITIONAL RISK ANALYSIS

In the system definition phase of the analysis, the ground rules are established and all pertinent information is collected. The ground rules of the analysis typically include the following:

- a. Goals and objectives—stating the motivation for conducting the risk analysis. Possible objectives are: satisfying regulatory requirements, doing a cost/benefit analysis, evaluating risks of a proposed expansion project.
- b. Required risk measures—spelling out the final results required to meet the objectives.
- c. System boundaries—defining the physical and operating limits of the system. Physical boundaries define the equipment included in the study. Operating boundaries include the function or operating mode of the system.
- d. Level of detail—defining how units within the system will be analyzed. Questions, such as “will each section of piping be modeled?” or “will piping be combined into groups for easier analysis?” need to be resolved early in the program.
- e. Data collection—defining what data must be captured and maintained. Up-to-date drawings and operating procedures are collected for future review. Other pertinent data, such as weather or population, may also be gathered, depending on the objectives of the study. If, for instance, the study pertains only in flammable hazards and the nearest residence is over a mile away, there would be no need to collect detailed offsite population data. A sample of data usually gathered in a risk analysis is provided in Table 4-1.

### 4.3 HAZARD IDENTIFICATION

The task of hazard identification has received much attention in recent years. As a result, it is probably the most mature of the various disciplines that comprise a risk analysis. Potential hazard scenarios need to be identified, and there are many techniques for doing so.

#### 4.3.1 Hazard and Operability Study

A Hazard and Operability Study (HAZOP) is a structured brainstorming exercise that uses a list of guidewords to stimulate team discussions. The guidewords initially focus on process parameters, such as flow, level, temperature, and pressure, and then branch out to include other concerns, such as human factors, and operating outside normal parameters. In a well-designed plant, the majority of identified potential deviations are typically operability issues. However, potential safety concerns and environmental considerations are also identified. The HAZOP is typically performed by a team

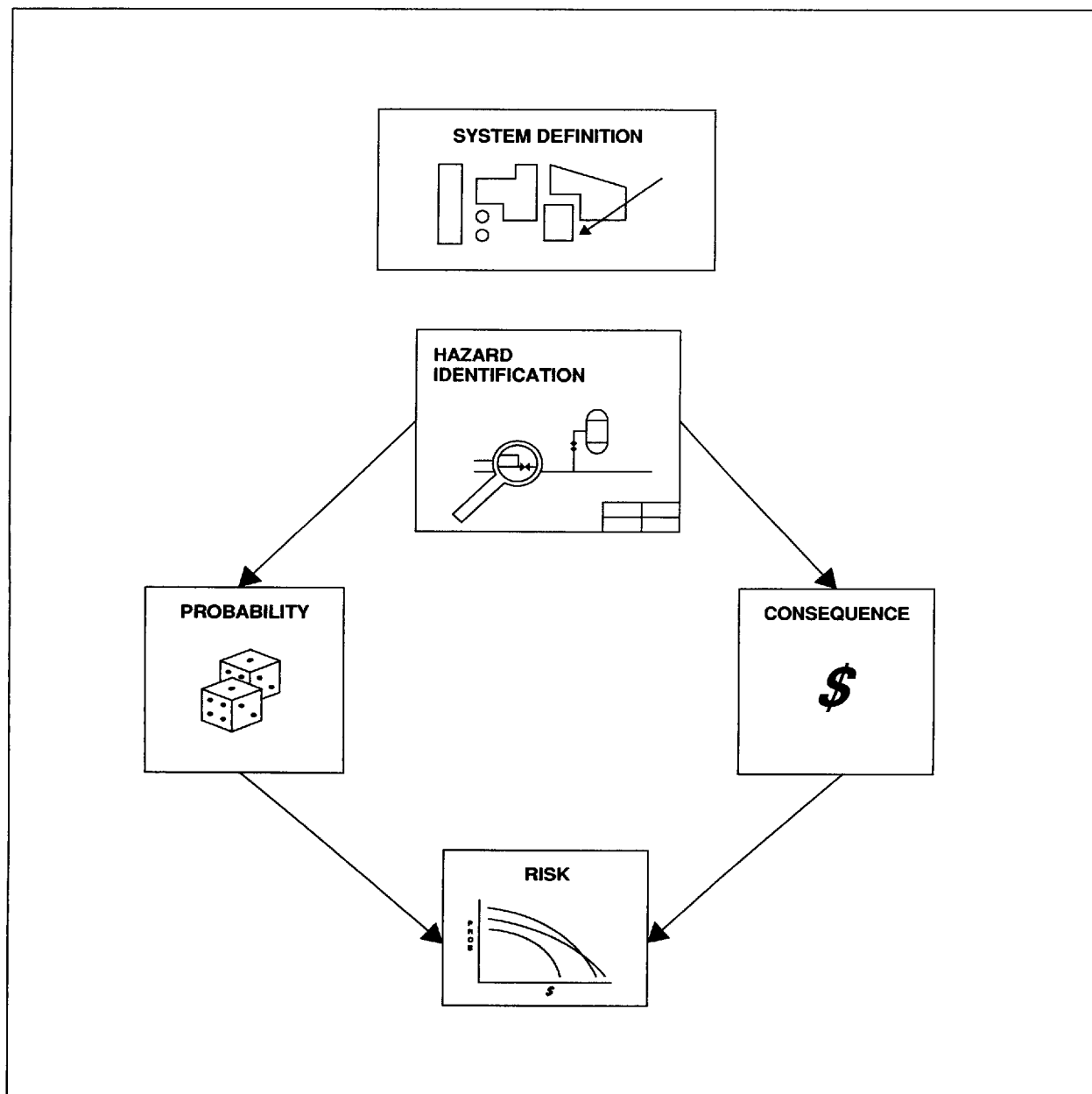


Figure 4-1—Overview of Risk Analysis

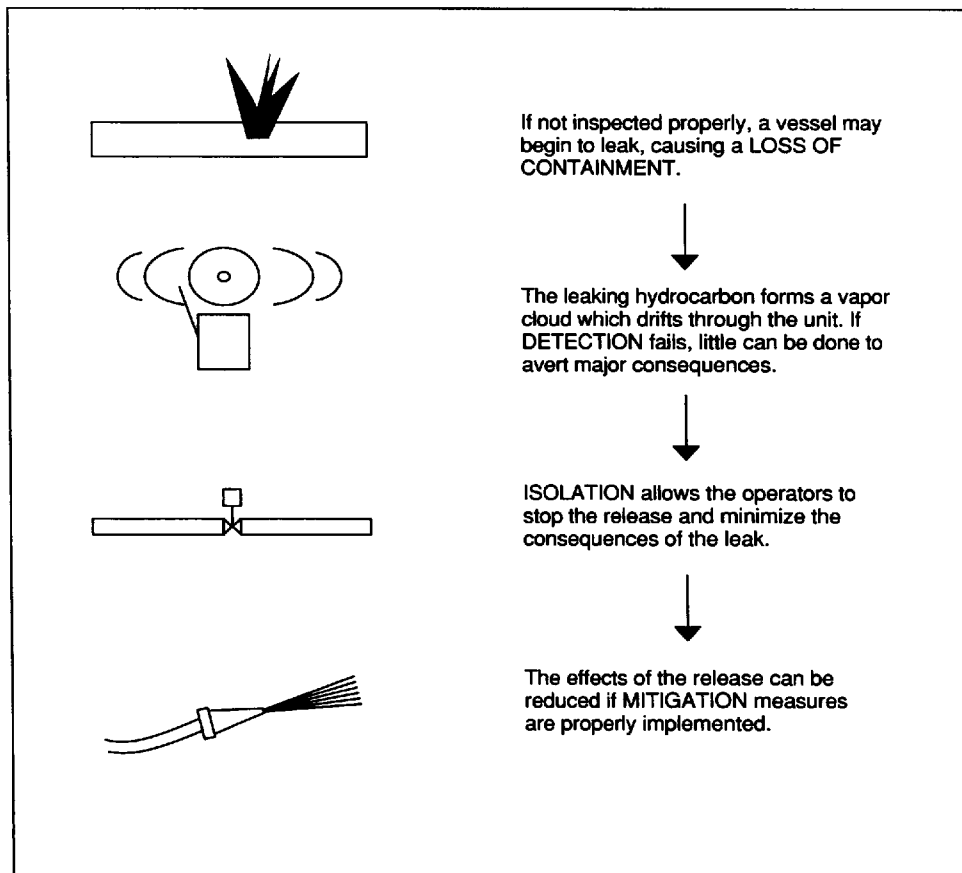


Figure 4-2—Events in a Typical Scenario

familiar with the process, rather than an individual, in order to brainstorm the potential hazards most effectively.

#### 4.3.2 Failure Modes and Effects Analysis

Failure Modes and Effects Analysis (FMEA) is an inductive analysis that systematically details, on the component level, all possible failure modes and identifies their resulting effects on the system. The technique is most effective at identifying single-point failures in a system. The FMEA is usually performed by filling in a table with the following information:

- Name.
- Equipment number.
- Description/use.
- Failure mode.
- Effect on system.
- Probability.
- Criticality.

It is common to have individuals perform FMEAs, but they can be performed by a team of experts in order to ensure the proper expertise is utilized.

#### 4.3.3 Checklists

Checklists are convenient to use if the process is not extremely complex and if the hazards are fairly well known. The checklists are typically developed from other detailed hazard identification studies, reports from previous accidents, or from expert judgment. Checklists are easy to apply, but they may omit a hazard that is unique to a particular process or facility.

#### 4.3.4 Fault Tree Analysis

Fault Tree Analysis is a deductive approach to hazard identification that focuses on the causes of an undesired event. The approach can be exhaustive to apply, yet it can produce very useful results in some situations. It is particularly effective at uncovering hazards due to secondary and tertiary causes.

### 4.4 PROBABILITY ASSESSMENT FOR A TRADITIONAL RISK ANALYSIS

The probability assessment is conducted to estimate the probability of occurrence for the scenarios identified in the



Table 4-1—Typical Data Collected for Risk Analysis

|                                                 |
|-------------------------------------------------|
| <b>HAZARDS INFORMATION</b>                      |
| Inventory of hazardous materials                |
| Material Safety Data Sheets                     |
| Existing HAZOP results                          |
| Location of ignition sources                    |
| <b>DESIGN AND OPERATING DATA</b>                |
| Vessel sizes                                    |
| Piping diameters and lengths                    |
| Operating conditions                            |
| Pump and compressor flow rates                  |
| Dike and drainage design                        |
| Operating procedures                            |
| <b>WEATHER DATA</b>                             |
| Average wind speeds                             |
| Probabilities of wind directions ("wind rose")  |
| <b>DETECTION SYSTEMS</b>                        |
| Gas detection                                   |
| Flame, fire detection                           |
| Toxic detection                                 |
| <b>FIRE PROTECTION SYSTEMS</b>                  |
| Extinguishing agents                            |
| Flow rates                                      |
| Actuation procedure                             |
| <b>HISTORICAL DATA</b>                          |
| Site history for release events                 |
| Occupational injury statistics                  |
| On-site population distribution (day and night) |
| <b>OFFSITE DATA</b>                             |
| Offsite population                              |
| Land use within 1–5 miles                       |
| Topography around site                          |

previous phase of the risk analysis. If a scenario occurs fairly frequently, it is best to use historical data to estimate the event's probability. However, it is often the case in the petroleum industry that the events of concern are so rare that sufficient data does not exist to estimate their probability based on historical data alone.

When historical data is lacking, a building-block approach is used. Probability estimates for all elements of the scenario are obtained and combined to predict the overall scenario probability.

The most common measure of probability for a scenario is its frequency. Frequency can be used for a single event or a series of events. Typically, a year is used as the standard time interval for a frequency analysis. Frequencies may be very small numbers, such as one in a million years for infrequent events, or they may be relatively high values, such as once a month or four times a day. If, for example, a pipe is known to leak about every five years or so, it would have a leak frequency of one in five years, or 0.2 per year. The term

recurrence period is sometimes used to refer to the reciprocal of the frequency. In our example, the recurrence period for the leak would be five years.

To obtain the frequency of the scenario ( $F_{\text{Scenario}}$ ), multiply the frequency of the leak ( $F_{\text{Leak}}$ ) by the probability of all events that follow ( $P_{\text{Outcome}}$ ). The resulting likelihood is the scenario's frequency. The mathematical representation of the likelihood of the sequence, in terms of frequency, is shown below:

$$F_{\text{Scenario}} = F_{\text{Leak}} \times P_{\text{Outcome}}$$

#### 4.5 CONSEQUENCE ANALYSIS FOR A TRADITIONAL RISK ANALYSIS

The consequences of a release from process equipment or pipework vary depending on such factors as physical properties of the material, its toxicity or flammability, weather conditions, release duration, and mitigation actions. The effects may impact plant personnel or equipment, population in the nearby residences, and the environment.

Hazardous consequences are estimated in five phases:

1. Discharge
2. Dispersion
- 3a. Flammable Effects
- 3b. Toxic Effects
- 3c. Environmental Effects

Depending on the material released, only one of the three effects (3a–3c) is usually calculated, although all of them may be possible with releases of certain mixtures. Refer to Section 7 for further information on hazardous effects, as they relate to RBI.

##### 4.5.1 Consequence Phase 1—Discharge

Sources of a hazardous release include pipe and vessel leaks and ruptures, pump seal leaks, and relief valve venting. The mass of material, its release rate, and material and atmospheric conditions at the time of release are key factors in calculating consequences.

Releases can be instantaneous, as in the case of a catastrophic vessel rupture or constant, as in a significant release of material over a limited period of time. The nature of the release will also affect the outcome. With appropriate equations, it is possible to model either of the two release conditions: instantaneous or constant.

##### 4.5.2 Consequence Phase 2—Dispersion

When a vapor or volatile liquid is released, it forms a vapor cloud that may or may not be visible. The vapor cloud is carried downwind as vapor and suspended liquid droplets. The cloud is dispersed through mixing with air until the concentration eventually reaches a safe level or is ignited.

Initially, a vapor cloud will expand rapidly because of the internal energy of the material. Expansion occurs until the

material pressure reaches that of ambient (atmospheric) conditions. For heavy gases, the material spreads along the ground and air is entrained in the vapor cloud, due to the momentum of the release. Turbulence in the cloud assists in mixing.

As the concentration drops, atmospheric turbulence becomes the dominant mixing mechanism, and a concentration profile develops across the vapor cloud. This concentration profile is an important feature in determining the impacts of the vapor cloud.

Several factors determine the phenomena of dispersion in Phase 2:

- a. **Density**—The density of the cloud relative to air is a very important factor affecting cloud behavior. If denser than air, the cloud will slump and spread out under its own weight as soon as the initial momentum of the release starts to dissipate. A cloud of light gas does not slump, but rises above the point of release.
- b. **Release Height and Direction**—Releases from a high elevation, such as a stack, can result in lower ground-level concentrations for both light and heavy gases. Also, upward releases will disperse more quickly than those directed horizontally or downwards, because air entrainment is unrestricted by the ground.
- c. **Discharge Velocity**—For materials that are hazardous only at high concentrations, such as flammable materials, the initial discharge velocity is very important. A flammable high velocity jet may disperse rapidly due to initial momentum mixing.
- d. **Weather**—The rate of atmospheric mixing is highly dependent on weather conditions at the time of release. Weather conditions are defined by three parameters—wind direction, speed and stability. The wind speed has two main effects on the release: it determines the overall rate at which the released material is carried downwind (the bulk velocity), and it determines the level of turbulence within the cloud, which decreases concentrations within the vapor cloud as it is diluted by air. Turbulence generally increases with wind speed.

### 4.5.3 Consequence Phase 3A—Flammable Effects

Five types of flammable effects can result from a burning hydrocarbon:

- a. Flash fire.
- b. Fireball.
- c. Jet flame.
- d. Pool fire.
- e. Explosion.

A cloud containing flammable material may not be immediately explosive. If the concentration of the initial release is above the material's upper flammability limit, it cannot ignite unless it has become diluted and a source of ignition is present. A flame propagates from the point of ignition through the region of the cloud that is between the upper and lower flammability limits.

The burn rate and flame velocity determines what type of fire results. Flash fires occur with a large, dilute cloud in which the material burns faster than the release rate. Consequences from a flash fire are only significant within or near the perimeter of the burning cloud.

A fireball occurs when a large quantity of relatively concentrated material ignites. Thermal radiation levels from the localized source are appreciable beyond the cloud boundaries, although they are usually short-lived.

Jet flames result when a high-momentum gas, liquid, or two-phased release is ignited. Thermal radiation levels are generally high in direct line with the jet. If a released material is not ignited immediately, a flammable plume or cloud may develop. On ignition, this will "flash" or burn back to form a jet flame.

Pool fires are caused by the ignition of pools of non-volatile or refrigerated materials. The effects of thermal radiation are limited to a region surrounding the pool itself.

Once a cloud dilutes to below its lower flammability limit, it can no longer ignite.

Under certain conditions, a flame front may travel very quickly, causing a pressure wave ahead of the front. If the flame speed is less than the speed of sound, a deflagration occurs. If the flame speed reaches the speed of sound, it results in a detonation. Explosion effects are the result of the overpressure wave generated by deflagrations or detonations. Explosion intensity is measured in terms of overpressure levels and duration.

Overpressure is most damaging to buildings and structures. In fact, during an explosion, people inside buildings may be at greater risk than those outside. Collapsing structures, flying brick and glass, and other missiles pose the greatest threat to people during an explosion.

### 4.5.4 Consequence Phase 3B—Toxic Effects

When a toxic material is released, the consequences are determined by both its concentration and duration. In other words, in order for a toxic effect to appear, the cloud must be of sufficient concentration and it must linger long enough for the effects to manifest themselves. The required concentration and duration are a function of the material itself.

Currently, a number of methods are used to assess the consequence of a toxic vapor cloud in terms of concentration and duration. For a variety of reasons, it is difficult to precisely evaluate toxic responses caused by acute exposures to hazardous materials. First, humans experience a wide range of adverse health effects from exposure. Second, there is a high degree of variation in response among individuals in a typical population. Factors such as age, health, and level of exertion can affect response to toxics. Third, much of the data on toxic responses has been taken from animal studies, which do not necessarily extrapolate well to humans.

There are two common approaches to evaluating the effects of a toxic release. The first uses a single criterion that identifies a specific level at which serious adverse health effects may occur. The second uses a probabilistic approach that reflects a probability of harm among a population for a given dose.

The latter approach uses what is called a probit function (6.2.3), which reflects the uncertainty in the response among humans to a given dose.

#### 4.5.5 Consequence Phase 3C—Environmental Effects

The release of a hazardous material, resulting from the types of scenarios that are addressed by the RBI, usually has limited consequences. The most serious environmental damage results from a large leak of a persistent material, such as crude oil, which may damage flora and fauna, and may require significant cleanup efforts.

Assessing environmental damage is extremely difficult because of the many factors involved in cleanup efforts and in estimating the costs for possible civil penalties or fines. Environmental damage is typically assessed based on a dollar-per-barrel estimate for the material and location of release.

### 4.6 WAYS TO PRESENT RISK RESULTS

There is no single way to measure or present an estimate of the risk of operating a chemical process. Historically, a number of measures have been used to express risk in the context of a risk analysis. Risks to people are normally presented in one of three ways described in the following sections.

#### 4.6.1 Risk Indices

Risk indices are a single number measure of risk. Some of the more common risk indices are:

- a. Fatal Accident Rate (FAR): the estimated number of fatalities per 108 exposure hours (roughly 1000 employee working lifetimes).
- b. Average Individual Risk: a similar concept to the FAR, but with a time period of one year.
- c. Average Rate of Death: the average number of fatalities from all incidents that might be expected per unit time.

#### 4.6.2 Individual Risk Measures

Individual risk measures consider the risk to an individual who might be located at any point in the effect zones of incident. Some of the more common individual risk measures are:

- a. Individual Risk Contours: the geographical distribution of individual risk. These contours show the expected frequency of an event capable of causing a fatality at a specific location, regardless of whether anyone is present at that location.
- b. Maximum Individual Risk: the individual risk to the person exposed to the highest risk in an exposed population. This can be found by calculating the individual risk at every geographical location, where people are present, and searching for the highest value.

#### 4.6.3 Societal Risk

Societal risk is a measure of risk to a group of people *in the effect zones of incidents*. It is most often expressed in terms of the frequency distribution of multiple fatality events. One common graphical presentation shows the frequency of events resulting in N or more fatalities. This type of graph is commonly known as an F/N plot. A stylized F/N plot is shown in Figure 4-3.

Societal risk measures are usually reduced to a single number risk index to allow easy comparison between different plants. One example is the Societal Risk Index (SRI) which is also known as the Potential Loss of Life (PLL). This index is calculated by summing all the risk pairs used to construct the F/N curve. What this means in practice is taking each data point generated in a traditional risk analysis for frequency of occurrence (F) and corresponding number of fatalities (N), multiplying F and N together, and summing the results. Note that this operation is done on the raw F and N data from a quantitative risk assessment. A common misunderstanding is that the points on the F/N plot can be used to calculate the SRI or PLL directly. The multiplying of risk pairs cannot be done directly from the F/N curve because the curve shows the frequency for N or more fatalities.

The difference between individual and societal risk is often confusing. The following scenario provides an illustration to help clarify the differences:

An office building, located near a high explosives depot, contains 400 people during the day, and one guard at night. If the likelihood of an explosion at the depot resulting in destruction of the building is constant throughout the 24-hour day, then each individual in that building is subject to a certain individual risk. This individual risk is independent of the number of persons present; it is the same for each of the 400-day people as it is for the one night person. In contrast, the societal risk is the risk to the whole population in the building, and is 400 times higher during the day when the building is occupied than it is at night when only one person is at risk.

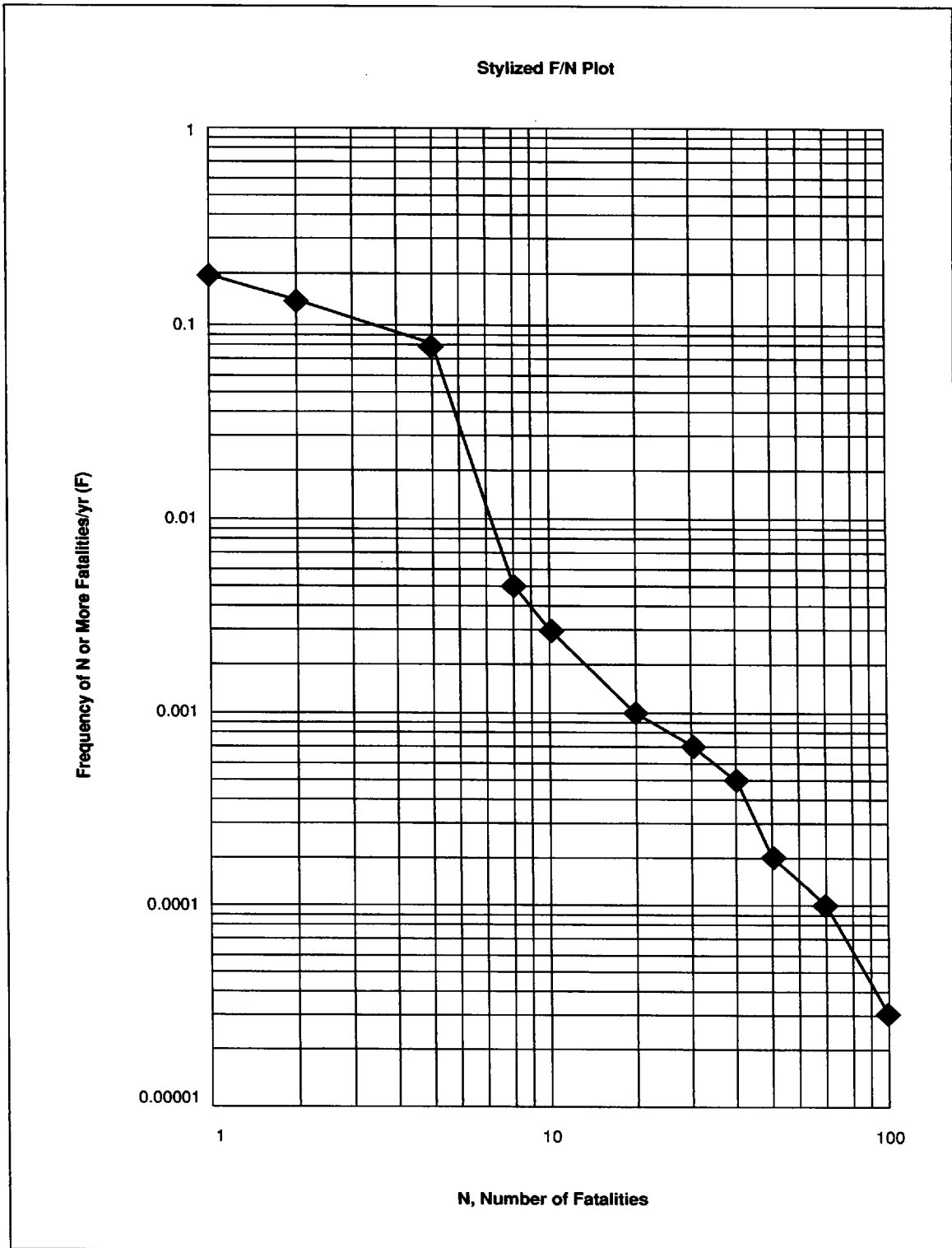


Figure 4-3—Stylized F/N Plot

## Section 5—Qualitative Approach To RBI (Operating Unit Basis)

### 5.1 GENERAL

This section describes the qualitative method for using risk to examine refinery and petrochemical operations for process hazards associated with pressure equipment integrity.

The qualitative approach is similar to that of the quantitative analysis, except that the qualitative approach requires less detail and is far less time consuming. While the results it yields are not as precise as those of the quantitative analysis, it provides a basis for prioritizing a risk based inspection program.

A qualitative analysis can be performed at any of the following levels:

- An operating unit—example: a complete crude processing unit.
- A major area or functional section in an operating unit—example: the vacuum section of the crude processing unit.
- A system—(a major piece of equipment and its auxiliary equipment)—example: an atmospheric heater including the feed preheat exchangers and charge pump.

Throughout this chapter, the term *unit* will be used in reference to any of these levels of analysis. The qualitative approach is strongly influenced by the number of equipment items in the unit being studied. Comparable studies should be based on similar equipment counts.

The qualitative analysis can be performed using the simple workbook approach presented in Appendix A, where a series of tables guides the user through the evaluation. The workbook was prepared with the philosophy that a typical refinery unit could be assessed in a few hours.

Qualitative RBI procedures have three functions:

- Screening the units within the site to select the level of analysis needed and to ascertain the benefit of further analyses (quantitative RBI or some other technique).
- Rating the degree of risk within the units and assigning them to a position within a risk matrix.
- Identifying areas of potential concern at the plant, which may merit enhanced inspection programs.

The analysis first determines a factor representing the likelihood of failure within the area, then a factor for the consequences. The two are then combined in the risk matrix to produce a risk rating for the unit.

Before embarking on the more detailed steps of the qualitative RBI analysis, the user can perform a simple screening process, to determine the relative risks among units.

#### 5.1.1 Rating Units Based on Potential Risk

The qualitative analysis determines a risk rating for an operating unit by categorizing the two elements of risk: likelihood and consequence. The chemicals involved and the

physical boundaries of the study area must be defined before the qualitative analysis is conducted.

The following sections provide a narrative overview of the factors that are derived during the qualitative analysis, as detailed in the workbook (see Appendix A).

#### 5.1.2 Likelihood Category

Part A of the workbook deals with the likelihood category, which is assigned by evaluating the six factors that affect the likelihood of a large leak. Each factor is weighted, and their combination results in the likelihood factor. This factor is plotted on the vertical axis of the risk matrix (see Figure 5-1). The six subfactors that make up the likelihood category are as follows:

- Amount of equipment (Equipment Factor, EF).
- Damage mechanisms (Damage Factor, DF).
- Appropriateness of inspection (Inspection Factor, IF).
- Current equipment condition (Condition Factor, CCF).
- Nature of the process (Process Factor, PF).
- Equipment design (Mechanical Design Factor, MDF).

The sum of these six components establishes the overall likelihood factor. The likelihood category is then assigned based on the overall likelihood factor.

**5.1.2.1** The *Likelihood Equipment Factor (EF)* is related to the number of components in the unit that have the potential to fail. The EF has a maximum value of 15 points.

**5.1.2.2** The *Likelihood Damage Factor (DF)* is a measure of the risk associated with known damage mechanisms in the unit. These mechanisms include levels of general corrosion, fatigue cracking, low temperature exposure, and high-temperature degradation. This factor receives a maximum value of 20 points in the overall assessment.

**5.1.2.3** The *Likelihood Inspection Factor (IF)* provides a measure of the effectiveness of the current inspection program and its ability to identify the active or anticipated damage mechanisms in the unit. It examines the types of inspections, their thoroughness, and the management of the inspection program. This factor is weighted with negative numbers because the quality of the inspection program will partially offset the likelihood of failure inherent in the damage mechanisms from the DF above. The maximum weight for the inspection factor is 15 points.

**5.1.2.4** The *Likelihood Condition Factor (CCF)* accounts for the physical condition of the equipment from a maintenance and housekeeping perspective. A simple evaluation is performed on the apparent condition and upkeep of the equipment from a visual examination. The CCF has a maximum value of 15 points.

**5.1.2.5** The *Likelihood Process Factor (PF)* is a measure of the potential for abnormal operations or upset conditions to initiate a sequence leading to a loss of containment. It is a function of the number of shutdowns or process interruptions (planned or unplanned), the stability of the process, and the potential for failure of protective devices because of plugging or other causes. The PF is weighted at a maximum of 15 points.

**5.1.2.6** The *Likelihood Mechanical Design Factor (MDF)* measures the safety factor within the design of the unit: whether it is designed to current standards, and how unique, complex, or innovative the unit design is. The MF is weighted at 15 points.

### 5.1.3 Consequence Category

There are two major potential hazards associated with refinery and petrochemical operations: (a) fire and explosion risks and (b) toxic risk. In determining the toxic consequence category, RBI considers only the acute effects.

The consequence analysis determines a damage consequence factor, in the Qualitative Workbook, Part B, and a health consequence factor in Part C. These determinations are usually made for each chemical. Many chemicals, however, exhibit a predominate risk (either fire/explosion or toxicity); thus if the predominant risk for a given chemical is known, it is necessary to determine only the factor for that risk and not for both. The consequence that generates the highest letter category is used to determine the qualitative risk rating. Note that if a chemical has no flammable characteristics, Part B can be skipped; if it is obvious that no toxic hazards are present, Part C can be skipped.

If there are several chemicals present in relatively large percentages in the area, the user should conduct the exercise several times—once for each of the chemicals present in relatively large proportions. A good rule of thumb is to review the chemicals with high health consequence, plus those that comprise at least 90–95% of the total mass of chemicals in the area.

**5.1.3.1** The *Damage Consequence Category*, Part B in the Qualitative Workbook, is derived from a combination of five elements that determine the magnitude of a fire and/or explosion hazard:

- a. Inherent tendency to ignite (Chemical Factor, CF).
- b. Quantity that can be released (Quantity Factor, QF).
- c. Ability to flash to a vapor (State Factor, SF).
- d. Possibility of auto-ignition (Auto-Ignition Factor, AF).
- e. Effects of higher pressure operations (Pressure Factor, PRF).
- f. Engineered safeguards (Credit Factor, CRF).
- g. Degree of exposure to damage (Damage Potential Factor, DPF).

**5.1.3.2** The *Consequence Chemical Factor (CF)*, a chemical's inherent tendency to ignite, is derived as a combination

of the material's flash factor and its reactivity factor. Flash factors correspond to the material's NFPA 1 Class rating, while the reactivity factor is a function of how readily the material can explode when exposed to an ignition source.

**5.1.3.3** The *Consequence Quantity Factor (QF)* represents the largest amount of material that could reasonably be expected to be released from a unit in a single event. The factor is based on the largest mass (in pounds) of flammable inventory in the unit.

**5.1.3.4** The *Consequence State Factor (SF)* is a measure of how readily a material will flash to a vapor when it is released to the atmosphere. It is determined from a ratio of the average process temperature to the boiling temperature at atmospheric pressure (using absolute temperatures in the ratio).

**5.1.3.5** The *Consequence Auto-Ignition Factor (AF)* is incorporated into the Qualitative Workbook to account for the increased probability of ignition for a fluid released at a temperature above its auto-ignition temperature.

**5.1.3.6** The *Consequence Pressure Factor (PRF)* is a measure of how quickly the fluid can escape. In general, liquids or gases processed at high pressure (greater than 150 psig) are more likely to be released quickly and result in an instantaneous-type release, with more severe consequences than a continuous-type release.

**5.1.3.7** A *Consequence Credit Factor (CRF)* is determined to account for the safety features engineered into the unit. These safety features can play a significant role in reducing the consequences of a potentially catastrophic release. Several aspects of unit design and operation are included in this factor:

- a. Gas detection capabilities.
- b. Inerting of atmosphere.
- c. Security of fire-fighting systems.
- d. Isolation capabilities.
- e. Blast protection.
- f. Rapid dump systems.
- g. Fireproofing of cables and structures.
- h. Capacity of fire water supply.
- i. Existence of fixed foam systems.
- j. Existence of fire water monitors.
- k. Water spray curtains.

**5.1.3.8** The potential for a fire or explosion to cause damage to the equipment in the unit is then determined by the *Damage Potential Factor (DPF)*. This is accomplished by a rough estimate of the value of equipment near large inventories of flammable or explosive materials.

**5.1.3.9** The *Damage Consequence Category* is then found by combining the above consequence factors and selecting the category based on ranges of these combined factors.

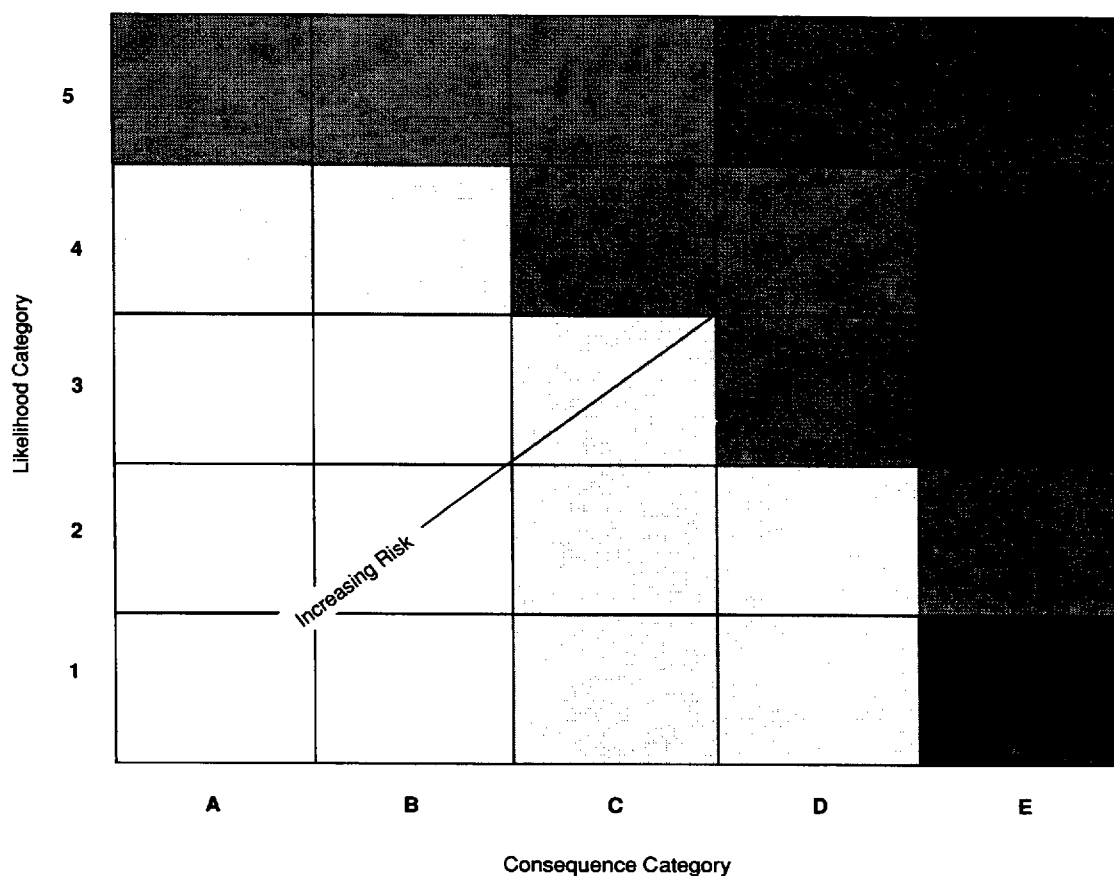


Figure 5-1—Qualitative Risk Matrix

**5.1.3.10** The *Health Consequence Category*, Part C in the Qualitative Workbook, is derived from the following elements that are combined to express the degree of a potential toxic hazard in a unit:

- Quantity and toxicity (Toxic Quantity Factor, TQF).
- Ability to disperse under typical process conditions (Dispersibility Factor, DIF).
- Detection and mitigation systems (Credit Factor, CRF).
- Population in vicinity of release (Population Factor, PPF).

**5.1.3.11** The *Toxic Quantity Factor (TQF)* is a measure of both the quantity and the toxicity of a material. The quantity portion is based on mass and is found using an approach similar to that shown in the quantity factor in Part B. The toxicity of the material is found using the NFPA toxicity factor,  $N_H$ .

**5.1.3.12** The *Dispersibility Factor (DIF)* is a measure of the ability of a material to disperse. It is determined directly from the normal boiling point of the material. The higher the boiling point, the less likely a material is to disperse.

**5.1.3.13** Again, a *Credit Factor (CRF)* is determined to account for the safety features engineered into the unit. Credit is given for the following:

- Toxic material detection capabilities.
- Isolation capabilities.
- Rapid dump systems.
- Mitigation systems (spray curtains, etc.).

**5.1.3.14** The *Population Factor (PPF)* is a measure of the number of people that can potentially be affected by a toxic release event. The population factor is scaled to show that, as more people are located in a hazard zone, a smaller percentage of the population will be affected. This result is supported by actual data from past toxic release events.

**5.1.3.15** The *Health Consequence Category* is then found by combining the above consequence factors and selecting the category based on ranges of these combined factors. The consequence categories (health and damage) are assigned letter scores, and the one with the highest value is plotted on the horizontal axis of the risk matrix to develop a risk rating for the unit.

### 5.1.4 Results

The likelihood category rating and the highest rating from either the damage or the health consequence categories are used to place each unit within a five-by-five risk matrix, shown as Figure 5-1. When results are plotted on the matrix, they give an indication of the level of risk for the unit being evaluated. When the qualitative analysis has included several materials or a multi-component mixture, the unit receiving the highest risk component will be the best indicator of whether further evaluation is necessary, as well as the urgency of that evaluation.

### 5.1.5 Identifying Areas of Inspection Concern

The risk matrix results can be used to locate areas of potential concern and to decide which portions of the process unit need the most inspection attention or other methods of risk reduction. It can also be used to decide whether a full quantitative study is justified.

The shadings provided in Figure 5-1 are guidelines for determining the degree of potential risk. The shadings are not symmetrical, as they are based on the assumption that, in almost every case, the consequence factor will carry more weight in determining total risk than will the likelihood component.

Without the shading, it seems clear that, as the plotted value for the likelihood and consequence categories moves toward the upper right of the matrix, the amount of risk increases. Companies generally will develop and apply their own criteria to determine when it becomes necessary to perform a quantitative RBI or adjust their inspection practices.

## 5.2 QUALITATIVE APPROACH TO RBI (EQUIPMENT BASIS)

### 5.2.1 Summary

The key variables identified that affect flammable consequences are fluid type (within a broadly defined range), inventory (again within large ranges) and fluid state in the process (liquid or gas). With just these three variables, a flammability consequence ranking can be determined. With additional information of temperature and pressure, the ranking can be refined.

Toxic consequences depend heavily upon the percentage of the process fluid that is toxic. Highly toxic process streams or those that contain a portion of highly toxic components can be evaluated using just the same inputs as above, plus a broadly estimated range of the percentage of the toxic component in the stream.

Business interruption is evaluated by a simple three-category assessment on production impact, plus information about whether excess production capacity exists, or if the product is in a sold-out market.

Likelihood is determined by simply estimating the susceptibility of the equipment to one or more of six damage mechanisms that contribute the most to process plant failures. An adjustment is made based on the length of time since that last inspection was performed on the equipment.

Finally, a suggested inspection frequency is delivered based on both the consequences and likelihood of failure.



## Section 6—Overview of Quantitative RBI

### 6.1 GENERAL

The failure of pressure-containing equipment and subsequent release of hazardous materials can lead to many undesirable effects. The RBI program has condensed these effects into four basic risk categories:

- a. Flammable events can cause damage in two ways: thermal radiation and blast overpressure. Most of the damage from thermal effects tends to occur at close range, but blast effects can cause damage over a larger distance from the blast center.
- b. Toxic releases, in the RBI approach, are only addressed when they affect personnel. Only acute, as opposed to chronic, exposure is considered. These releases can cause effects at greater distances than flammable events. Unlike flammable releases, toxic releases do not require an additional event (e.g., ignition, as in the case of flammables) to cause an undesirable event.
- c. Environmental risks are an important component to any consideration of overall risk in a processing plant. The RBI program focuses on acute environmental risks rather than chronic risks from low-level emissions. Environmental damage can occur with the release of many materials; however, the predominant environmental risk comes from the release of large amounts of liquid hydrocarbons outside the bounds of the plant.
- d. Business interruption can often exceed the costs of equipment and environmental damage and, therefore, should be accounted for in the RBI program. Equipment replacement costs (accounted for in flammable damage estimates) can be trivial compared to the business loss of a critical unit for an extended period of time.

An overview of the quantitative RBI prioritization is shown in Figure 6-1. The approach begins with the extraction of process, equipment, and other information from the RBI database. Various scenarios are then developed to show how leaks may occur and how they can progress into undesirable events. In the quantitative RBI calculation, one of the four defining factors in a leak scenario is the size of the hole in the equipment. Since there is a one-to-one correspondence between hole sizes and scenarios, these terms are often used interchangeably.

The risk calculation is performed for each scenario, for all four risk categories, if desired. The risk for each equipment item is then found by summing the individual risk components from each scenario (hole size) calculation.

### 6.2 CONSEQUENCE OVERVIEW

The consequences of releasing a hazardous material are estimated in five distinct steps:

- a. Estimate the release rate or the total mass available for release.

- b. Determine if the fluid is dispersed in a rapid manner (instantaneous) or slowly (continuous).
- c. Determine if the fluid disperses in the atmosphere as a liquid or a gas.
- d. Estimate the impacts of any mitigation system.
- e. Estimate the consequences.

As shown in Figure 6-2, the environmental consequence takes its input directly from the release rate or mass information. Also, business interruption risks are derived directly from results found for flammable events.

#### 6.2.1 Estimating The Release Rate

The RBI methodology groups all releases into either of two types: instantaneous or continuous. Instantaneous releases are those that empty the contents of a vessel in a relatively short period of time, as in the case of brittle failure of a vessel. Continuous releases are those that occur over a long period of time at a relatively constant rate. Section 7.5 describes the rules that categorize each release as either instantaneous or continuous. Equations are then used to model the two release types.

#### 6.2.2 Predicting Type of Outcomes

In the context of the RBI analysis, the outcome of a release *refers to the physical behavior of the hazardous material*. Examples of outcomes are safe dispersion, explosion, or jet fire. Outcomes should not be confused with consequences. For the RBI analysis, *consequence* (discussed in the next section) refers to the adverse effects on people, equipment, and the environment *as a result of the outcome*.

The actual outcome of a release depends on the nature and properties of the material released. A brief discussion of possible outcomes for various types of events is provided below.

##### 6.2.2.1 Flammable Effects

Six possible outcomes can result from the release of a flammable fluid:

- a. *Safe dispersion* occurs when flammable fluid is released and then disperses without ignition. The fluid disperses to concentrations below its flammable limits before it encounters a source of ignition. Although no flammable outcome occurs, it is still possible that the release of a flammable material (primarily liquids) could cause adverse environmental effects. Environmental events are addressed separately.
- b. *Jet fires* result when a high-momentum gas, liquid, or two-phase release is ignited. Radiation levels are generally high close to the jet. If a released material is not ignited immediately, a flammable plume or cloud may develop. On ignition, this will flash or burn back to form a jet flame.

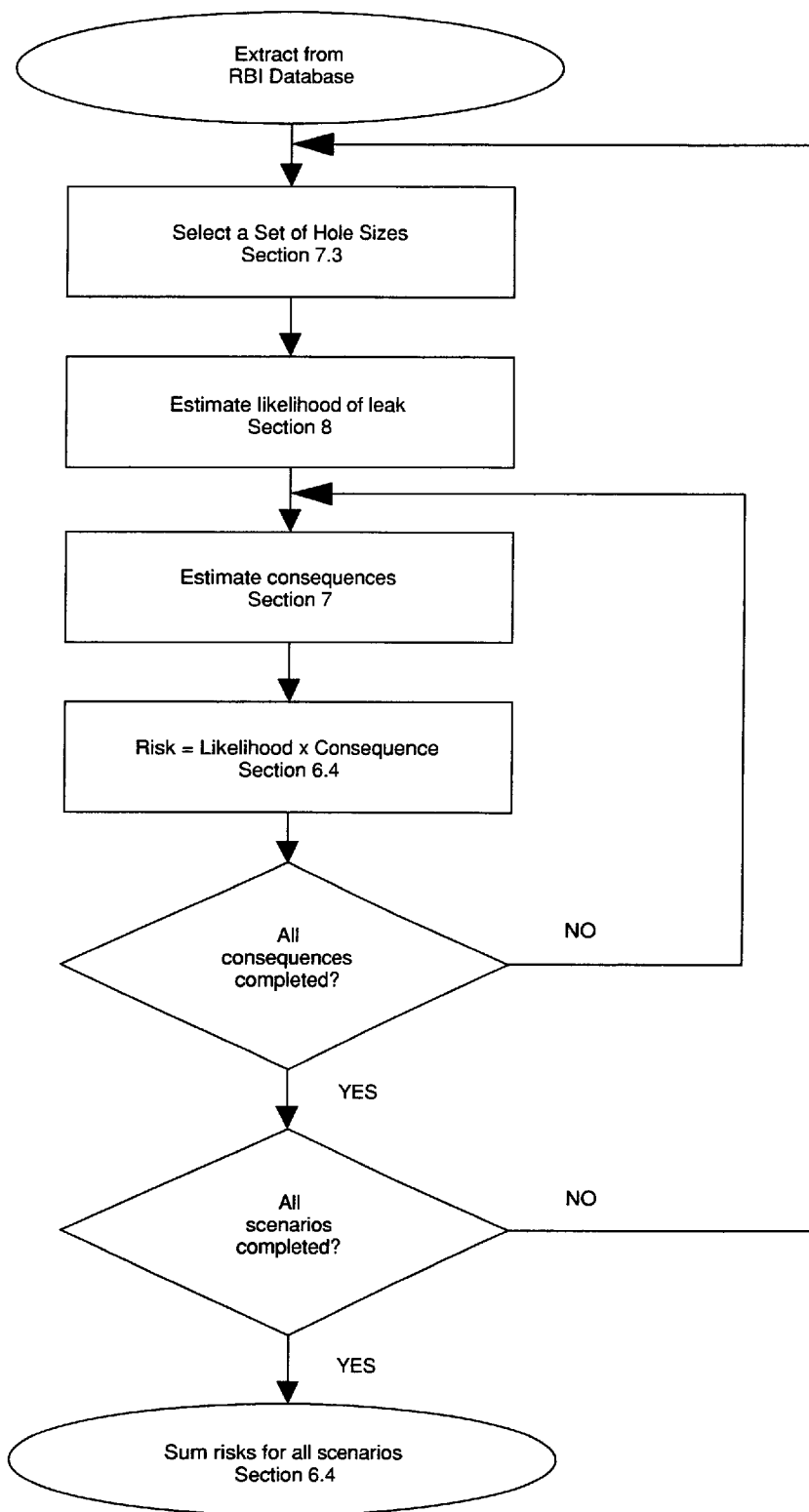


Figure 6-1—Overview of Quantitative RBI Approach

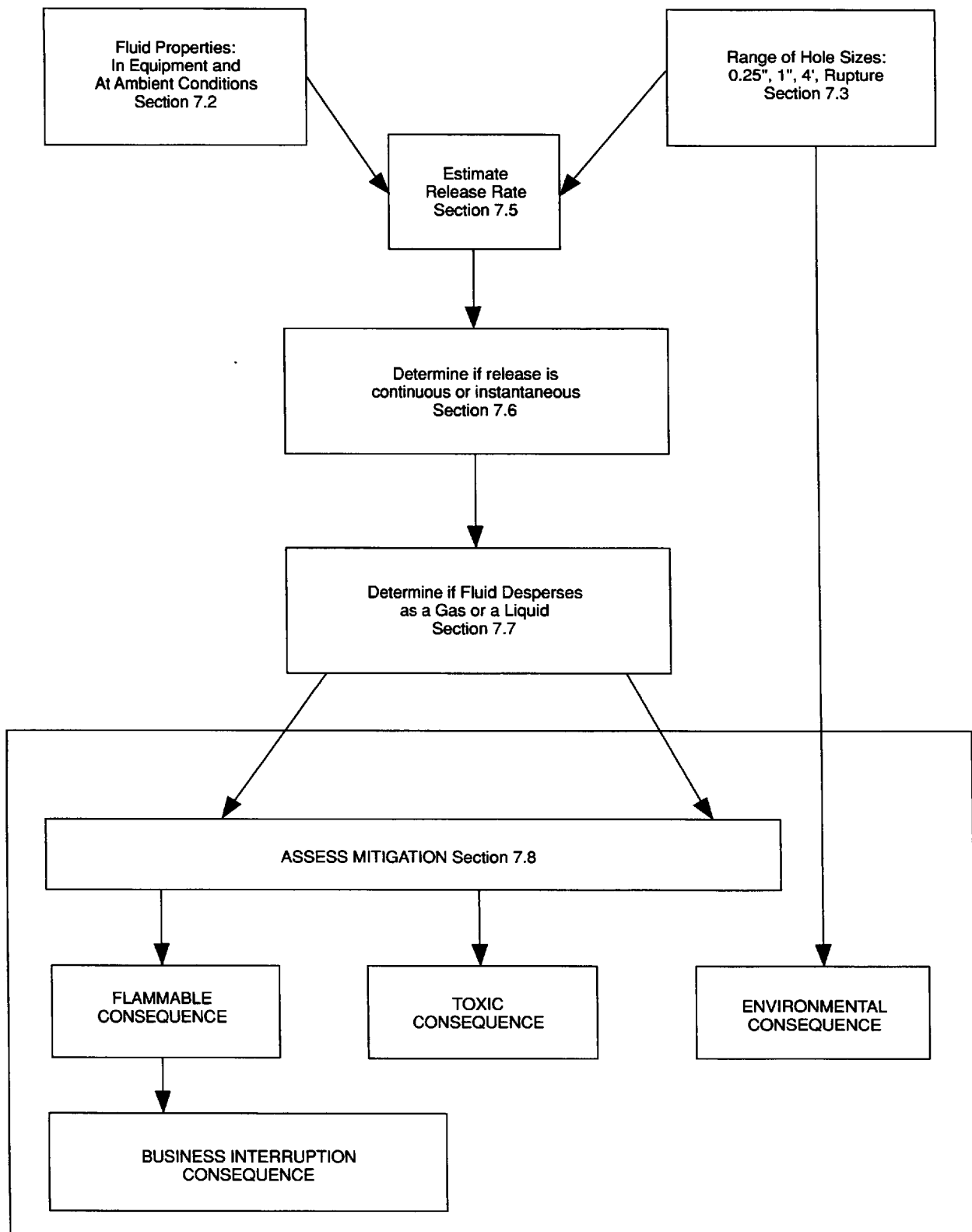


Figure 6-2—Overview of Consequence Calculation

c. *Explosions* occur under certain conditions when a flame front travels very quickly. Explosions cause damage by the overpressure wave that is generated by the flame front.

d. *Flash fires* occur when a cloud of material burns under conditions that do not generate significant overpressure. Consequences from a flash fire are only significant within the perimeter and near the burning cloud. Flash fires do not cause overpressures high enough to damage equipment.

e. A *fireball* occurs when a large quantity of fuel ignites after it has undergone only limited mixing with the surrounding air. Thermal effects from the fireball extend well beyond the boundaries of the fireball, but they are usually short-lived.

f. *Pool fires* are caused when liquid pools of flammable materials ignite. The effects of thermal radiation are limited to a region surrounding the pool itself.

### 6.2.2.2 Toxic Effects

Two outcomes are possible when a toxic material is released: safe dispersal or manifestation of toxic effects.

In order for a toxic effect to occur, two conditions must be met:

- The release must reach people in a sufficient concentration.
- It must linger long enough for the effects to become harmful.

If either of the conditions are not met, the release of the toxic material results in safe dispersal, a technical term used in risk assessment to indicate that the incident falls below the pass/fail threshold (see Section 6.2.3).

If both of the above conditions (concentration and duration) are met, and people are present, toxic exposure will occur.

### 6.2.2.3 Environmental Effects

From an environmental standpoint, safe dispersal occurs if the released material is entirely contained within the physical boundaries of the facility. If the material cannot be contained, the release of a hazardous material will result in a spill. Ground water contamination is considered to be a release that goes beyond plant boundaries.

### 6.2.2.4 Business Interruption Effects

Business interruption effects are analyzed using flammable event consequences. As such, the outcomes associated with the business interruption analysis are the same as those listed previously for the effects of flammable events.

## 6.2.3 Applying Effect Models To Estimate Consequences

The first two steps in the consequence calculation predict the outcome in terms of physical phenomena. The third step

is to convert the outcomes to consequences. Effect models, also known as *impact criteria*, are used to estimate consequences from an outcome.

RBI uses two distinct types of impact criteria to estimate consequences from a given outcome: the *direct effect model* and the *probit*. Direct effect models are used for flammable, environmental, and business interruption consequences, while toxic consequences are estimated using the probit, for example.

The direct effect model uses a pass/fail approach to predict the consequence from a given outcome. It assumes that no effect is observed if the outcome is below the predefined threshold. It assumes a single effect for any outcome above the threshold. This approach is fairly coarse since, in reality, a spectrum of effects are observed for a range of outcomes.

The probit (short for probability unit) is a statistical method of assessing a consequence. It reflects a generalized time-dependent relationship for a variable that has a probabilistic outcome described by the normal distribution. The probit has a mean value of 5 and a variance of 1.

## 6.3 LIKELIHOOD OVERVIEW

The likelihood analysis begins with a database of generic failure frequencies for the specific equipment types. These generic frequencies are then modified by two terms, the equipment modification factor ( $F_E$ ) and the management system evaluation factor ( $F_M$ ). An adjusted failure frequency is calculated by multiplying the generic failure frequency by the two modification factors. The following equation demonstrates the likelihood analysis:

$$Frequency_{adjusted} = Frequency_{generic} \times F_E \times F_M \quad (6.1)$$

The database of generic failure frequencies is based on a compilation of available equipment failure histories from multiple industries. From these data, generic probabilities of failure have been developed for each type of equipment and each diameter of piping.

The equipment modification factor examines the specific environment in which each item of equipment operates, then develops a modification factor unique to that equipment item.

The management systems evaluation factor adjusts for the influence of the facility's Process Safety Management system on the mechanical integrity of the plant. This adjustment is applied equally to all equipment items in a study.

This factor will only provide discrimination for studies at different plants or between units with differing management systems. However, the evaluation process can be used to improve the effectiveness of the PSM program, thereby reducing overall risk.

## 6.4 CALCULATION OF RISK

Given the RBI definition for risk as the product of the consequence and the likelihood of failure, in mathematical terms, the risk for a scenario is

$$\text{Risks} = C_s \times F_s \quad (6.2)$$

where

$S$  = scenario number

$C_s$  = consequence (area in ft<sup>2</sup> or \$) for scenario,  $s$

$F_s$  = failure frequency (per year) for scenario,  $s$

For each equipment item, the risk is the sum of the risks for all of that item's scenarios. The units of risk depend on the consequence of interest: In the RBI approach, ft<sup>2</sup> per year for flammable or toxic consequences, dollars per year for environmental or business interruption. The risk for an equipment item is

$$\text{Risk}_{\text{item}} = \sum_s \text{Risk}_s \quad (6.3)$$

where

$\text{Risk}_s$  = risk for a scenario (ft<sup>2</sup> or \$ per year)

$\text{Risk}_{\text{item}}$  = risk per equipment item (ft<sup>2</sup> or \$ per year)

An example of the risk calculation is presented below.

Suppose, after carrying out both the likelihood and consequence calculations, an equipment item showed the following results:

| Scenario                                                   | Likelihood           | Consequence      | Risk              |
|------------------------------------------------------------|----------------------|------------------|-------------------|
|                                                            | Frequency (per year) | Equipment Damage | Equipment Damage  |
| 1/4 inch leak                                              | $6.9 \times 10^{-6}$ | 540 sq. ft.      | .0037 sq. ft./yr. |
| 1 inch leak                                                | $1.7 \times 10^{-5}$ | 7,500 sq. ft.    | .1275 sq. ft./yr. |
| 4 inch leak                                                | $1.7 \times 10^{-6}$ | 17,500 sq. ft.   | .0289 sq. ft./yr. |
| Rupture                                                    | $1.0 \times 10^{-6}$ | 130,000 sq. ft.  | .13 sq. ft./yr.   |
| Total Risk of Equipment Damage for Item - 0.29 sq. ft./yr. |                      |                  |                   |

Note: that by examining the risks for each hole size, the risk is dominated almost equally by the 1 inch and rupture cases. This may not be intuitive at first, but careful study of the methods used can reveal unanticipated results that may imply actions that were not at first obvious.

## Section 7—Consequence Analysis

### 7.1 GENERAL

The consequence analysis in an RBI program is performed to aid in establishing a relative ranking of equipment items on the basis of risk. The consequence measures presented in this chapter are intended as simplified methods for establishing relative priorities for inspection programs. If more accurate consequence estimates are needed, the analyst should refer to more rigorous analysis techniques, such as those used in quantitative risk analysis.

An overview of the RBI consequence calculation is shown in Figure 7-1. The consequences of releasing a hazardous fluid are estimated in seven distinct steps:

- Determining representative fluid and its properties (Section 7.2).
- Selecting a set of hole sizes, to find the possible range of consequences in the risk calculation (Section 7.3).
- Estimating the total amount of fluid available for release (Section 7.4).
- Estimating the potential release rate (Section 7.5).
- Defining the type of release, to determine the method used for modeling the dispersion and consequence (Section 7.6).
- Selecting the final phase of the fluid, i.e., a liquid or a gas (Section 7.7).
- Evaluating the effect of post-leak response (Section 7.8)
- Determining the area potentially affected by the release, or the relative cost of the leak due to down time or environmental cleanup (Section 7.9).

### 7.2 DETERMINING A REPRESENTATIVE FLUID AND ITS PROPERTIES

Because very few refinery streams are pure materials, the selection of a representative material almost always involves making some assumptions. These assumptions, and the sensitivity of the results, depend to a degree upon the type of consequences that are to be evaluated. Table 7-1 presents the list of materials modeled in RBI for the Base Resource Document.

For mixtures, the representative material should be defined firstly by the NBP and MW, and secondly by the density. If these values are unknown, one for the mixture can be calculated using:

$$Property_{Mix} = \sum x_i \cdot Property_i$$

where

$x_i$  = mole fraction of the component and  $Property_i$  may be NBP, MW, or Density

The properties of fluids can typically be found in standard chemical reference books. It should be noted that, in the RBI consequence discharge model, the NBP is used in determining the phase of the material following the release and either the MW or density is used in determining the release rate, depending whether a liquid or gas, respectively, is released. For evaluating consequences, however, the following is important:

*Flammable consequence results are not highly sensitive to the exact material selected, provided the molecular weights are similar, because air dispersion properties and heats of combustion are similar for all hydrocarbons with similar molecular weights. This is particularly true for straight chain alkanes, but becomes less true as the materials become less saturated or aromatic.*

Hence, one should be very careful when applying the RBI BRD consequence formulas to materials (such as aromatics, chlorinated hydrocarbons, etc.) not already defined in the BRD. In such cases, it is recommended that test runs using quantitative consequence analysis programs be made to more appropriately select the correct material that yields similar consequence areas.

The fluid properties that apply to the BRD representative fluids are listed in Table 7-2. The Cp constants are used in the Ideal Gas Heat Capacity Equation:  $A + BT + CT^2 + DT^3$  (J/mol-K).

For example, applying the aforementioned method, a material containing 10 mol% C<sub>3</sub>, 20 mol% C<sub>4</sub>, 30 mol% C<sub>5</sub>, 30 mol% C<sub>6</sub>, and 10 mol% C<sub>7</sub> would have the following average "key" properties:

$$MW = 74.8$$

$$AIT = 629.8^\circ F$$

$$NBP = 102.6^\circ F$$

$$DENSITY = 38.8 \text{ lb./ft}^3$$

Thus, the best selection from the materials in the representative fluids list would be C<sub>3</sub>–C<sub>5</sub>, since the property of first importance is the NBP, and it is non-conservative to select a representative fluid with a higher NBP than the fluid being considered.

If the mixture contains inerts such as CO<sub>2</sub>, water, etc., the flammable/toxic materials of concern should be chosen, excluding these materials. This is a somewhat crude assumption that will result in slightly conservative results, but it is a fair enough estimation for this process. For instance, if the material is 93 mol% water and 7 mol% C<sub>20</sub>, simply model it as C<sub>20</sub>, using the corresponding inventory of the hydrocarbon.

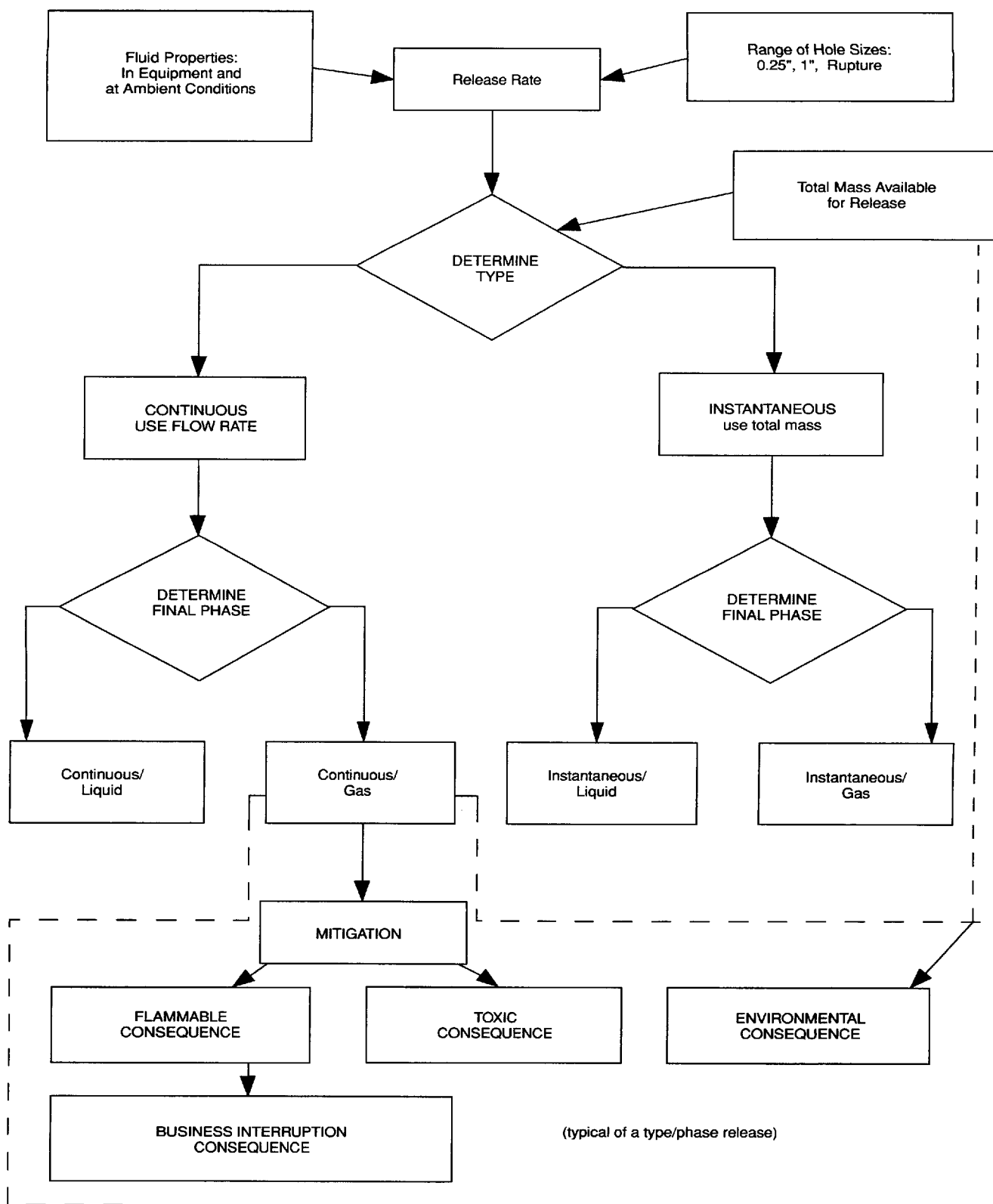


Figure 7-1—RBI Consequence Calculation Overview

Table 7-1—List of Materials Modeled in RBI Base Resource Document

| Representative Material           | Examples of Applicable Materials               |
|-----------------------------------|------------------------------------------------|
| C <sub>1</sub> – C <sub>2</sub>   | Methane, ethane, ethylene, LNG                 |
| C <sub>3</sub> – C <sub>5</sub>   | Propane, butane, isobutane, LPG                |
| C <sub>5</sub>                    | Pentane                                        |
| C <sub>6</sub> – C <sub>8</sub>   | Gasoline, naphtha, light straight run, heptane |
| C <sub>9</sub> – C <sub>12</sub>  | Diesel, kerosene                               |
| C <sub>13</sub> – C <sub>16</sub> | Jet fuel, kerosene, atmospheric gas or         |
| C <sub>17</sub> – C <sub>25</sub> | Gas oil, typical crude                         |
| C <sub>25+</sub>                  | Residuum, heavy crude                          |
| H <sub>2</sub>                    | Hydrogen only                                  |
| H <sub>2</sub> S                  | Hydrogen sulfide only                          |
| HF                                | Hydrogen fluoride                              |
| Water                             | Water                                          |
| Steam                             | Steam                                          |
| Acid (low)                        | Low-pressure acid with caustic                 |
| Acid (medium)                     | Low-pressure acid with caustic                 |
| Acid (high)                       | Low-pressure acid with caustic                 |
| Aromatics                         | Benzene, toluene, zylene                       |
| Styrene                           | Styrene                                        |

Table 7-2—Properties of the BRD Representative Fluids

| Fluid            | Molecular Weight | Density lb/ft <sup>3</sup> | Normal Boiling Point °F | Ambient State | Cp Gas Constant A | Cp Gas Constant B | Cp Gas Constant C | Cp Gas Constant D | Auto Ignition Temperature °F |
|------------------|------------------|----------------------------|-------------------------|---------------|-------------------|-------------------|-------------------|-------------------|------------------------------|
| C1-C2            | 23               | 5.639                      | 193                     | Gas           | 12.3              | 1.150E-01         | -2.870E-05        | -1.300E-09        | 1,036                        |
| C3-C4            | 51               | 3.610                      | 6.3                     | Gas           | 2.632             | 0.3188            | 1.347E+04         | 1.466E-08         | 696                          |
| C6-C8            | 100              | 42.702                     | 210                     | Liquid        | -5.146            | 6.762E-01         | -3.651E-04        | 7.658E-08         | 433                          |
| C9-C12           | 149              | 45.823                     | 364                     | Liquid        | -8.5              | 1.010E+00         | -5.560E-04        | 1.180E-07         | 406                          |
| C13-C16          | 205              | 47.728                     | 502                     | Liquid        | -11.7             | 1.390E+00         | -7.720E-04        | 1.670E-07         | 396                          |
| C17-C25          | 280              | 48.383                     | 651                     | Liquid        | -22.4             | 1.940E+00         | -1.120E-03        | -2.530E-07        | 396                          |
| C25+             | 422              | 56.187                     | 981                     | Liquid        | -22.4             | 1.940E+00         | -1.120E-03        | -2.530E-07        | 396                          |
| H <sub>2</sub>   | 2                | 4.433                      | -423                    | Gas           | 27.1              | 9.270E-03         | -1.380E-05        | 7.650E-09         | 752                          |
| H <sub>2</sub> S | 34               | 61.993                     | -75                     | Gas           | 31.9              | 1.440E-03         | 2.430E-05         | -1.180E-08        | 500                          |
| HF               | 20               | 60.370                     | 68                      | Gas           | 29.1              | 6.610E-04         | -2.030E-06        | 2.500E-09         | 32,000                       |
| Water            | 18               | 62.3                       | 212                     | Liquid        | 32.4              | 0.001924          | 1.05E-05          | -3.6E-07          | n/a                          |
| Steam            | 18               | 62.3                       | 212                     | Gas           | 32.4              | 0.001924          | 1.05E-05          | -3.6E-07          | n/a                          |
| Acid (low)       | 18               | 62.3                       | 212                     | Liquid        | 32.4              | 0.001924          | 1.05E-05          | -3.6E-09          | n/a                          |
| Acid (med.)      | 18               | 62.3                       | 212                     | Liquid        | 32.4              | 0.001924          | 1.05E-05          | -3.6E-09          | n/a                          |
| Acid (high)      | 18               | 62.3                       | 212                     | Liquid        | 32.4              | 0.001924          | 1.05E-05          | -3.6E-09          | n/a                          |
| Aromatics        | 104              | 42.7314                    | 293.3                   | Liquid        | -28.25            | 0.6159            | -4.02E-04         | 9.94E-08          | 914                          |
| Styrene          | 104              | 42.7314                    | 293.3                   | Liquid        | -28.25            | 0.6159            | -4.02E-04         | 9.94E-08          | 914                          |

Note: Reid, Robert C, et. al., *The Properties of Gases and Liquids*, 4th Edition, McGraw-Hill, New York, 1987.



### 7.3 SELECTING A SET OF HOLE SIZES

In order to carry out the RBI risk calculation in a practical manner, a discrete set of hole sizes must be used. It would be impractical to perform risk calculations for a continuous spectrum of hole sizes. Experience has shown that limiting the number of hole sizes allows for an analysis that is manageable yet still reflects the range of possible outcomes.

The RBI method uses a predefined set of hole sizes. This approach provides reproducibility and consistency between studies, and it increases the ease with which the process can be automated with software.

RBI defines hole sizes that represent small, medium, large, and rupture cases. The range of hole sizes is chosen to address potential onsite and offsite consequences. For onsite effects, small and medium hole-size cases usually dominate the risk because of their much higher likelihood and potential for onsite consequences. For offsite effects, medium and large hole-size cases will dominate the risk. To address both onsite and offsite risk, and to provide good resolution between equipment items, RBI generally uses four hole sizes per equipment item.

Table 7-3 presents the hole sizes selected for the RBI program.

Table 7-3 defines the possible sizes of holes used in the risk calculation. Depending on the piece of equipment, all of the above hole sizes may not be feasible. The following paragraphs provide a discussion of how the hole sizes are selected for specific pieces of equipment:

#### 7.3.1 Pipe Hole Size Selection

Piping uses the standard four hole sizes:  $\frac{1}{4}$ -inch, 1-inch, 4-inch, and rupture, provided the diameter of the leak is less than, or equal to, the diameter of the pipe itself. For example, a 1-inch pipe can have only two hole sizes,  $\frac{1}{4}$ -inch and rupture, because the largest possible choice is equivalent to the 1-inch hole size. A 4-inch pipe can have three:  $\frac{1}{4}$ -inch, 1-inch, and rupture, for the same reason.

#### 7.3.2 Pressure Vessel Hole Size Selection

Pressure vessels assume the standard four hole sizes for all sizes and types of vessels. Equipment types included in this general classification are:

- a. *Vessel*—standard pressure vessels such as KO drums, accumulators, and reactors.
- b. *Filter*—standard types of filters and strainers.
- c. *Column*—distillation columns, absorbers, strippers, etc.
- d. *Heat Exchanger Shell*—shell side of reboilers, condensers, heat exchangers.
- e. *Heat Exchanger Tube*—tube side of reboilers, condensers, heat exchangers.
- f. *Fin/Fan Coolers*—fin/fan-type heat exchangers.

Table 7-3 —Hole Sizes Used in Quantitative RBI Analysis

| Hole Size | Range                    | Representative Value                                  |
|-----------|--------------------------|-------------------------------------------------------|
| Small     | 0 – $\frac{1}{4}$ inch   | $\frac{1}{4}$ inch                                    |
| Medium    | $\frac{1}{4}$ – 2 inches | 1 inch                                                |
| Large     | 2 – 6 inches             | 4 inches                                              |
| Rupture   | > 6 inches               | entire diameter of item, up to a maximum of 16 inches |

#### 7.3.3 Pump Hole Size Selection

Pumps are assumed to have three possible hole sizes:  $\frac{1}{4}$ -inch, 1-inch, and 4-inch. If the suction line is less than 4 inches, the last possible hole size will be the full suction line diameter. Ruptures are not modeled for pumps, and the use of three hole sizes for pumps is consistent with historical failure data.

#### 7.3.4 Compressor Hole Size Selection

Both centrifugal and reciprocating compressors use two hole sizes: 1-inch and 4-inch (or suction line full bore rupture, whichever is the smaller diameter). The selection of only two hole sizes is consistent with historical failure data.

#### 7.3.5 Atmospheric Storage Tank Hole Size Selection

Atmospheric storage tanks have unique features requiring special hole sizes. They are usually surrounded by a berm, creating a secondary containment area for leakage. The floor of the tank may leak for extended periods of time before detection, leading to underground contamination.

RBI assumes that these tanks are at least partially above-ground, and that the time to detect a leak is dependent on detection methods. Because of the above features and limitations, the following hole sizes and locations are assumed for atmospheric storage tanks:

- a.  $\frac{1}{4}$ -inch, 1-inch, and 4-inch leaks from above-ground sides of the tank.
- b. Tank rupture from the walls or from the floor, provided the floor rupture can flow freely onto the ground around the tank.
- c.  $\frac{1}{4}$ -inch and 1-inch leaks in the floor of an atmospheric storage tank.

### 7.4 ESTIMATING THE TOTAL AMOUNT OF FLUID AVAILABLE FOR RELEASE

The RBI consequence calculation requires an upper-limit for the amount of fluid that can be released from an equipment item (the *Inventory*). In theory, the total amount of fluid that can be released is the amount that is held within pressure-containing equipment such as vessels and piping, between

isolation valves that can be quickly closed. In reality, emergency operations can be performed over time to close manual valves, deinventory sections, or otherwise stop a leak. In addition, piping restrictions and differences in elevation can serve to effectively slow or stop a leak.

Note: The Inventory calculation as presented here is used as an upper limit and does not indicate that this amount of fluid would be released in all leak scenarios.

The quantitative RBI approach does not use detailed fluid hydraulic modeling. Rather, a simple procedure is used to determine the mass of fluid that could *realistically* be released in the event of a leak. When an equipment item is evaluated, its inventory is combined with other attached equipment that can realistically contribute fluid mass to leaking item. These items together form an *Inventory Group*. The procedure estimates available mass as the lesser of two quantities:

- a. The mass of the equipment item plus the mass that can be added to it within three minutes from the Inventory Group, assuming the same flow rate from the leaking equipment item, but limited to an 8-inch leak in the case of ruptures.
- b. The total mass of the modeled fluid in the Inventory Group associated with the piece of equipment.

The three-minute time limit for the added fluid is based on the dynamics of a large leak scenario. In a large leak, the leaking vessel will begin to deinventory, while the secondary vessel provides makeup to feed the leak. Large leaks are expected to last for only a few minutes, because of the many cues given to operators that a leak exists. The amount of time the rupture will be fed is expected to range from 1 to 5 minutes. Three minutes was chosen since it is the midpoint of this range. Even though the three-minute assumption is not as applicable to small leaks, it is far less likely that small leaks will persist long enough to empty the leaking vessel and continue on to empty other vessels.

Estimating the inventories for equipment and piping can be done using the following guidelines:

#### 7.4.1 Equipment Items

Liquid inventories within equipment items can be calculated. In line with coarse risk methodology (and some from API RP 521), the following assumptions in Table 7-4 can be used (note that normal operating levels should be used, if known):

#### 7.4.2 Liquid Systems

For liquid systems, define the representative equipment groups which, given a certain failure within that group, could result in similar consequences. Examples of liquid systems may include:

- a. The bottom half of a distillation column, its reboiler, and the associated piping.

Table 7-4—Assumptions Used When Calculating Liquid Inventories Within Equipment

| Equipment Item                      | Volume Percent                    |
|-------------------------------------|-----------------------------------|
| Liquid/Liquid Columns               | 50% of each material              |
| Tray Columns (treated as two items) |                                   |
| top half                            | 50% vapor                         |
| bottom half                         | 50% liquid                        |
| Knock-out Pots and Dryers           | 10% liquid                        |
| Accumulators and Drums              | 50% liquid                        |
| Separators                          | 50% volume of each material/phase |
| Pumps and Compressors               | Negligible                        |
| Heat Exchangers                     | 50% shell-side, 25% tube-side     |
| Furnaces                            | 50% liquid/50% vapor in the tubes |
| Piping                              | 100% full                         |

- b. An accumulator and its outlet piping.
- c. A long feed pipeline.
- d. A storage tank and its outlet piping.
- e. A series of heat exchangers and the associated piping.

Once the liquid piping and equipment groups are established, then add the inventories for each item to obtain the group inventory. This liquid inventory would be used for each equipment item modeled from that group.

#### 7.4.3 Vapor Systems

For vapor systems, common equipment and piping group for vapor systems include:

- a. The top half of the distillation column, its overhead piping, and the overhead condenser.
- b. A vent header line, its knock-out pot, and its exit line.

For vapor systems, however, the inventory is not likely to be governed by the amount of vapor in the equipment items, but rather the flow rate through the system. Therefore, it would be desired to use this flow rate for a given period of time (say, 60 minutes) and use this inventory. If this rate is not known and, since flashing may also occur from the liquid system, it may be preferable to simply use the upstream group's liquid inventory. This, however, is likely to lead to a somewhat more conservative inventory.

#### 7.4.4 Two-Phase Systems

For two-phase systems, such as separators, the potential spill inventory of the liquid is most likely to be used, as it is the assumption that the release occurs at the base of the equipment item. Again, some conservatism may occur. For two-phase pipes, the upstream spill inventory can be a consideration such

that, if a majority is liquid, then the liquid spill inventory should be determined. Conversely, if upstream inventory is primarily two-phase or gaseous, then the vapor inventory can be calculated with an allowance for the liquid portion.

## 7.5 ESTIMATING THE RELEASE RATE

The RBI consequence analysis models all releases as one of two types:

- Instantaneous—also called a “puff” release.
- Continuous—also known as a “plume” release.

An instantaneous release is one that occurs so rapidly that the fluid disperses as a single large cloud or pool. A continuous release is one that occurs over a longer period of time, allowing the fluid to disperse in the shape of an elongated ellipse (depending on weather conditions). At the onset of the analysis, it is not known if the leak can produce a puff or a plume. Therefore, the analyst must first calculate a theoretical release rate, then apply judgment to determine which release type is more appropriate.

Release rates depend upon the physical properties of the material, the initial phase, and the process conditions. The analyst chooses the correct release rate equation, *based on the phase of the material when it is inside the equipment item*, and its discharge regime (sonic or subsonic), as the material is released. Two-phase flow equations have been omitted in the interest of simplicity.

The initial state of the fluid is required to be defined as either liquid or gas. The “state” is simply the phase of the hazardous material that could be released while in the vessel/line, prior to coming into contact with the atmosphere (i.e., flashing and aerosolization is not included at this point).

For two-phase systems (condensers, phase separators, evaporators, reboilers, etc.), some judgment as to the handling of the model needs to be taken into account. In most cases, choosing liquid as the initial state is more conservative, but may be preferred. One exception may be for two-phase pipes. Here, the upstream spill inventory can be a consideration such that, if a majority of the upstream material that could be released is vapor, then “vapor” should be selected. The results should also be checked accordingly for conservatism. It is also suggested that items containing two-phases have a closely approximated potential spill inventory; this should assist in not overpredicting results. The release rate equations are as follows:

### 7.5.1 Liquid Discharge Rate Calculation

Discharges of liquids through a sharp-edged orifice are described by the work of Bernoulli and Toricelli (Perry and Green, 1984) and can be calculated as:

$$Q_L = C_d A \sqrt{2\rho - \rho \frac{g_c}{144}} \quad (7.1)$$

where

$Q_L$  = liquid discharge rate (lbs/sec),

$C_d$  = discharge coefficient,

$A$  = hole cross-sectional area (sq in),

$\rho$  = density of liquid (lb/ft<sup>3</sup>),

$DP$  = difference between upstream and atmospheric pressure (psid),

$g_c$  = conversion factor from lb<sub>f</sub> to lb<sub>m</sub> (32.2 lb<sub>m</sub>-ft / lb<sub>f</sub>-sec<sup>2</sup>).

The discharge coefficient for fully turbulent flow from sharp-edged orifices is 0.60 to 0.64. A value of 0.61 is recommended for the RBI calculations. The above equation is used for both flashing and non-flashing liquids.

### 7.5.2 Gas Release Rate Equations

There are two regimes for flow of gases through an orifice: sonic (or choked) for higher internal pressures, and subsonic flow for lower pressures. Gas release rates, therefore, are calculated in a two-step process. The first step determines which flow regime is present. The second step estimates the release rate, using the equation for the specific flow regime. The following equation defines the pressure at which the flow regimes change from sonic to subsonic:

where

$$P_{trans} = P_a \left( \frac{K+1}{2} \right)^{\frac{k}{k-1}} \quad (7.2)$$

$P_{trans}$  = transition pressure (psia),

$P_a$  = atmospheric pressure (psia),

$K = C_p / C_v$ ,

$C_p$  = ideal gas heat capacity at constant pressure (Btu/lb mol °F),

$C_v$  = ideal gas heat capacity at constant volume (Btu/lb mol °F).

For cases where the pressure within the equipment item is greater than  $P_{trans}$ , use the sonic gas discharge rate equation and, for cases where the pressure is less than or equal to  $P_{trans}$ , use the subsonic gas discharge rate equation.

### 7.5.3 Sonic Gas Discharge Rate Calculation

Discharges of gases at sonic velocity through an orifice (Perry and Green, 1984) can be calculated as:

$$W_g(\text{sonic}) = C_d A P \sqrt{\left(\frac{KM}{RT}\right) \frac{g_c}{144} \left(\frac{2}{K+1}\right)^{\frac{k+1}{k-1}}} \quad (7.3)$$

where

$w_g(\text{sonic})$  = gas discharge rate, sonic flow (lbs/sec),

$C_d$  = discharge coefficient (for gas  $C_d = 0.85$  to  $1$ ),

$A$  = cross-section area (in.<sup>2</sup>),

$P$  = upstream pressure (psia),

$M$  = molecular weight (lb/lb-mol),

$R$  = gas constant (10.73 ft<sup>3</sup>-psia/lb-mol°R),

$T$  = upstream temperature (°R).

#### 7.5.4 Subsonic Gas Discharge Rate Calculation

Discharges of gases at subsonic velocity through an orifice can be calculated as:

$$W_g(\text{subsonic}) = C_d A P \sqrt{\left(\frac{M}{RT}\right) \frac{g_c}{144} \left(\frac{2K}{K-1}\right) \left(\frac{P_a}{P}\right)^{\frac{2}{K}} \left[1 - \left(\frac{P_a}{P}\right)^{\frac{k-1}{K}}\right]} \quad (7.4)$$

where

$w_g(\text{subsonic})$  = gas discharge rate, subsonic flow (lbs/sec)

All other parameters are as defined previously.

#### 7.6 DETERMINING THE TYPE OF RELEASE

Different methods are used to estimate the effects of an instantaneous versus a continuous type of release. The calculated consequences can differ greatly, depending on the type chosen to represent the release. Therefore, it is very important that a release is properly categorized into one of the two release types.

The criteria below stem from a review of historical data on fires and explosion, which shows that *unconfined* vapor cloud explosions are more likely to occur if more than 10,000 pounds of fluid are released in a short period of time. The modeling of continuous releases uses a lower probability for a vapor cloud explosion (VCE) following a leak. Thus, using this threshold to define continuous release reflects the tendency for amounts released in a short period of time, less than 10,000 pounds, to result in a flash fire rather than a VCE.

The following process is provided to determine the appropriate method for modeling the release. The process is depicted in Figure 7-2.

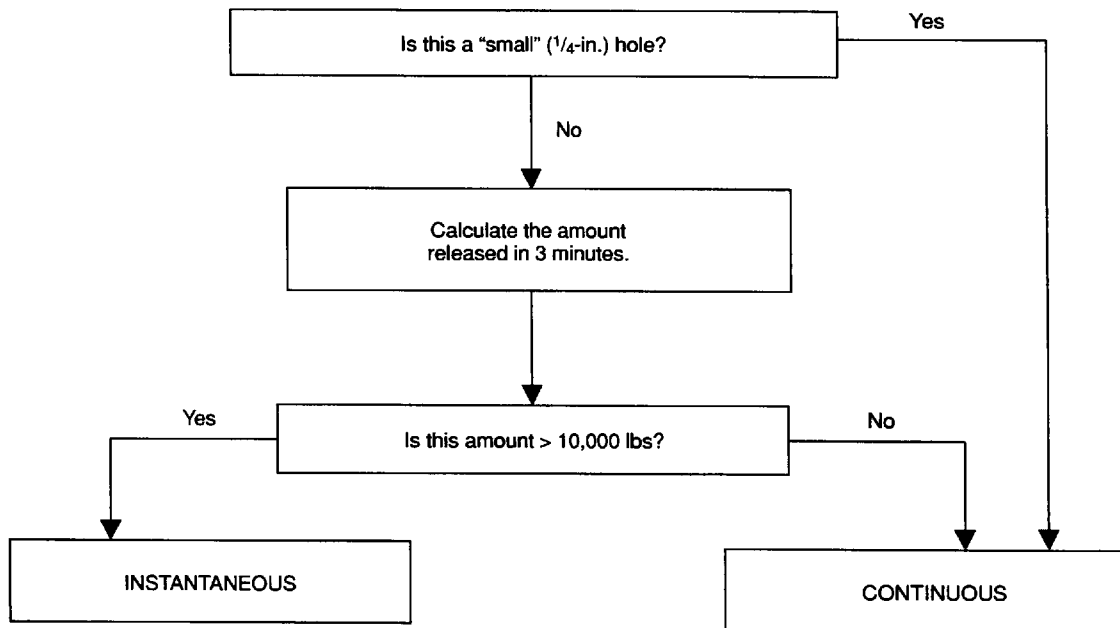


Figure 7-2—Process to Determine the Type of Release

Table 7-5—Guidelines for Determining the Phase of a Fluid

| Phase of Fluid at Steady-State Operating Conditions | Phase of Fluid at Steady-State Ambient Conditions | Determination of Final Phase for Consequence Calculation                                                              |
|-----------------------------------------------------|---------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------|
| gas                                                 | gas                                               | model as gas                                                                                                          |
| gas                                                 | liquid                                            | model as gas                                                                                                          |
| liquid                                              | gas                                               | model as gas <i>unless</i> the fluid boiling point at ambient conditions is greater than 80°F, then model as a liquid |
| liquid                                              | liquid                                            | model as liquid                                                                                                       |

- All “Small” ( $1/4$ -in.) holes are modeled as continuous leaks.
- If it takes less than three minutes to release 10,000 pounds, the release from the given hole size is instantaneous, and it is modeled as a puff type of release.
- All slower release rates are modeled as Continuous.

## 7.7 DETERMINING THE FINAL PHASE OF THE FLUID

The dispersion characteristics of a fluid after release are strongly dependent on the phase (i.e., gas or liquid) in the environment. If there is no change of phase for the fluid when going from the steady-state operating conditions to steady-state ambient conditions, the final phase of the fluid is the same as the initial phase. However, if the fluid would tend to change state upon release, the phase of the material may be difficult to assess for the purpose of the consequence calculations. Table 7-5 provides simple guidelines for determining the phase of the fluid for the consequence calculation, if more sophisticated methods are not available. Consultation with process or operations personnel is appropriate in this determination.

## 7.8 EVALUATING POST-LEAK RESPONSE

Evaluating post-leak response is the final step in the consequence analysis. In this step, the various mitigation systems in place are evaluated for effectiveness in limiting consequences.

### 7.8.1 Approach To Evaluating Post-Leak Response

Two key parameters are determined in the post-leak response evaluation: release duration and reduction of the spread of hazardous materials. Release duration is a critical parameter in toxic and environmental consequence evaluations. Flammable materials quickly reach steady-state concentrations, therefore, duration is not a significant factor for flammables. Business interruption risks are estimated directly from flammable consequence results so they, too, are not highly sensitive to the leak duration.

For these reasons, different approaches are necessary for evaluating the post-leak response for the 4 types of consequences analyzed in RBI. The specific approaches for each consequence type are described briefly below.

#### 7.8.1.1 Flammable Releases

For the release of flammable materials, isolation valves serve to reduce the release rate or mass by a specified amount, depending on the quality of these systems.

#### 7.8.1.2 Toxic Releases

Release duration is estimated from the types of leak detection and isolation systems. The duration is then used as direct input to the estimation of toxic consequences. Mitigation systems, such as water curtains, will serve to reduce the spread of material which, in turn, will reduce the final consequences.

#### 7.8.1.3 Releases to the Environment

Environmental consequences are mitigated in two ways: physical barriers act to contain leaks on-site, and detection and isolation systems limit the duration of the leak. In RBI, the volume contained onsite is accounted for directly in the spill calculation. Detection and isolation systems serve to reduce the duration of the leak and, thus, the final spill volume.

### 7.8.2 Assessing Post-Leak Response Systems

All petrochemical processing plants have a variety of mitigation systems that are designed to detect, isolate, and reduce the effects of a release of hazardous materials. RBI has developed a simplified methodology for assessing the effectiveness of various types of mitigation systems.

Mitigation systems affect a release in different ways. Some systems reduce duration by detecting and isolating the leak. Other mitigation systems minimize the chances for ignition or the spread of material. In RBI, consequence mitigation systems are treated in two ways:

- Systems that detect and isolate a leak.
- Systems that are applied directly to the hazardous material to reduce consequences.

### 7.8.3 Assessing Detection and Isolation Systems

Detection and isolation systems are assessed using a two-step process:

- Determine the classification rating of the applicable detection and isolation system.

b. Refer to the specific consequence calculation section to estimate the effects of the detection and isolation systems on the consequences.

Table 7-6 provides guidance to the user for assigning a qualitative letter rating (A, B, or C) to the unit's detection and isolation systems. These letter ratings are later used in the consequence estimation sections to determine the effect of the mitigation systems on final consequences. Note that Detection System A is usually found only in specialty chemical applications and is not often used in refineries. It is provided here for completeness.

*The information presented in Table 7-6 is used only when evaluating the consequences of continuous-type releases. In other words, if more than 10,000 pounds of hydrocarbon are released in 3 minutes, the process of assessing detection and isolation capability is not applied.*

Using human-factors analysis techniques, the quality ratings of the detection and isolation systems have been translated into an estimate of leak duration. Total leak duration, presented in Table 7-7, is the sum of the following times:

- a. Time to detect the leak.
- b. Time to analyze the incident and decide upon corrective action.
- c. Time to complete appropriate corrective actions.

The values in Table 7-7 are suggested for use in RBI. If the user has access to better information regarding operator response times, use those values instead of Table 7-7.

#### 7.8.4 Assessing Direct-Application Systems

There is no standard approach to assessing systems that apply the mitigation measures directly to the hazardous material. For this reason, these types of mitigation systems are addressed separately for each consequence type. Refer to 7.9 for details.

### 7.9 DETERMINING THE CONSEQUENCES OF THE RELEASE

The following sections present the methodology for calculating the consequence measures for each of the four major consequence categories: flammable, toxic, environmental, and business interruption.

#### 7.9.1 Overview of Consequence Estimation

The 4 major consequence categories are analyzed in different ways:

- a. The flammable and toxic consequences are calculated using event trees to determine the probabilities of various outcomes (e.g., flash fires, vapor cloud explosions), combined with summary equations based on using computer modeling to determine the magnitude of the consequence.
- b. Business interruption risks are estimated as a function of the flammable consequence results.
- c. Environmental consequences are determined directly from mass available for release or from the release rate.

Table 7-6—Detection and Isolation System Rating Guide

| Type of Detection System                                                                                                                           | Detection Classification |
|----------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------|
| Instrumentation designed specifically to detect material losses by changes in operating conditions (i.e., loss of pressure or flow) in the system. | A                        |
| Suitably located detectors to determine when the material is present outside the pressure-containing envelope.                                     | B                        |
| Visual detection, cameras, or detectors with marginal coverage                                                                                     | C                        |
| Type of Isolation System                                                                                                                           | Isolation Classification |
| Isolation or shutdown systems activated directly from process instrumentation or detectors, with no operator intervention.                         | A                        |
| Isolation or shutdown systems activated by operators in the control room or other suitable locations remote from the leak.                         | B                        |
| Isolation dependent on manually-operated valves                                                                                                    | C                        |

Table 7-7—Leak Durations Based on Detection and Isolation Systems

| Detection System Rating | Isolation System Rating | Leak Duration                                                                               |
|-------------------------|-------------------------|---------------------------------------------------------------------------------------------|
| A                       | A                       | 20 minutes for 1/4-inch leaks<br>10 minutes for 1-inch leaks<br>5 minutes for 4-inch leaks  |
| A                       | B                       | 30 minutes for 1/4-inch leaks<br>20 minutes for 1-inch leaks<br>10 minutes for 4-inch leaks |
| A                       | C                       | 40 minutes for 1/4-inch leaks<br>30 minutes for 1-inch leaks<br>20 minutes for 4-inch leaks |
| B                       | A or B                  | 40 minutes for 1/4-inch leaks<br>30 minutes for 1-inch leaks<br>20 minutes for 4-inch leaks |
| B                       | C                       | 1 hour for 1/4-inch leaks<br>30 minutes for 1-inch leaks<br>20 minutes for 4-inch leaks     |
| C                       | A, B, or C              | 1 hour for 1/4-inch leaks<br>40 minutes for 1-inch leaks<br>20 minutes for 4-inch leaks     |

The flammable and toxic consequence computations have been calculated using a hazards analysis screening software package containing atmospheric dispersion and consequence modeling routines. As will be seen in the next sections, the output has been distilled to a usable form by correlating consequences directly to release parameters. As a result, consequences are estimated from a set of empirical equations, using release rate (for continuous releases) or mass (for instantaneous releases) as input. If RBI users so desire, they may substitute comparable dispersion and consequence models for the predefined summary equations provided in this chapter.

## 7.9.2 General Input Assumptions

The computer modeling used to determine final consequences required specific input regarding meteorological and release conditions. Meteorological conditions representative of the Gulf Coast annual averages were used for RBI consequence analysis. The input assumptions were as follows:

- Atmospheric Temperature 70°F.
- Relative Humidity 75%.
- Wind Speed 8 mph.
- Stability Class D.
- Surface Roughness Parameter 0.1 (typical for processing plants).
- Initial pressures and temperatures typical of medium-pressure processing conditions within a refinery.
- Both vapor and liquid releases from a vessel containing saturated liquid, with release orientation horizontal downwind at an elevation of ten feet over a concrete surface.

Analysis has shown that these assumptions are satisfactory for a wide variety of plant conditions.

## 7.9.3 Flammable/Explosive Consequences

For flammable materials, RBI measures consequences in terms of the *area* affected by the ignition of a release. There are several potential outcomes for any release involving a flammable material; however, RBI determines a single combined result as the average of all possible outcomes, weighted according to probability. The probability of an outcome is different from, and should not be confused with, the likelihood of a release (see Section 8). The probability of an outcome represents the probability that a specific physical phenomenon (outcome) will be observed after the release has occurred.

Potential release outcomes for flammable materials are:

- Safe Dispersion (SD).
- Jet Fire (JF).
- Vapor Cloud Explosion (VCE).
- Flash Fire (FF).
- Fireball (BL).
- Liquid Pool Fire (PF).

A brief description of each outcome has been provided in 6.2.2.1.

## 7.9.3.1 Flammable Consequence Analysis Procedure

The determination of flammable consequences has been greatly simplified for this BRD, allowing the RBI analyst to determine approximate consequence measures using only the following information:

- The representative material and its associated properties.
- The type and phase of dispersion.
- The release rate or mass, depending on the type of dispersion and the effects of mitigation measures.

**7.9.3.1.1** The consequence results are derived using the following steps:

Step 1. Note the type of release and the phase of dispersion.

Step 2. Choose the appropriate table, based on the type of release:

- Table 7-8 for continuous type releases where auto ignition is not likely.
- Table 7-9 for instantaneous type releases where auto ignition is not likely.
- Table 7-10 for continuous type releases where auto ignition is likely.
- Table 7-11 for instantaneous type releases where auto ignition is likely.

Step 3. Once the correct table has been selected, refer to the correct half of the table to use:

- Left half for gases.
- Right half for liquids.

Step 4. Choose the appropriate column, based on the desired effect of interest:

- Area of equipment damage.
- Area of potential fatalities.

Step 5. Select the equation in the appropriate column corresponding to the representative material.

Step 6. Replace the "X" in the equation with either the release rate or release mass, depending on the type of release. The resulting value is the probability-weighted affected area, in square feet.

**7.9.3.1.2** The consequence tables referred to in the above procedure were derived using the following 3-step process:

Step 1. Predicting the probabilities of various outcomes

Step 2. Calculating the consequences for each type of outcome.

Step 3. Combining the consequences into a single probability-weighted empirical equation.

a. Step 1—Predicting Probabilities of Flammable Outcomes

Each outcome is the result of a chain of events. Event trees, as shown in Figure 7-3, were used in RBI to visually depict the possible chain of events that lead to each outcome. The

Table 7-8—Continuous Release Consequence Equations—Auto Ignition Not Likely<sup>a</sup>

| Material                         | Final Phase Gas                             |                                       | Final Phase Liquid                          |                                       |
|----------------------------------|---------------------------------------------|---------------------------------------|---------------------------------------------|---------------------------------------|
|                                  | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) |
| C <sub>1</sub> –C <sub>2</sub>   | $A = 43 x^{0.98}$                           | $A = 110 x^{0.96}$                    |                                             |                                       |
| C <sub>3</sub> –C <sub>4</sub>   | $A = 49 x^{0.98}$                           | $A = 125 x^{0.96}$                    |                                             |                                       |
| C <sub>5</sub>                   | $A = 25.2 x^{0.98}$                         | $A = 62.1 x^{1.00}$                   | $A = 536 x^{0.90}$                          | $A = 1544 x^{0.90}$                   |
| C <sub>6</sub> –C <sub>8</sub>   | $A = 29 x^{0.98}$                           | $A = 68 x^{0.96}$                     | $A = 182 x^{0.89}$                          | $A = 516 x^{0.89}$                    |
| C <sub>9</sub> –C <sub>12</sub>  | $A = 12 x^{0.98}$                           | $A = 29 x^{0.96}$                     | $A = 130 x^{0.90}$                          | $A = 373 x^{0.89}$                    |
| C <sub>13</sub> –C <sub>16</sub> |                                             |                                       | $A = 64 x^{0.90}$                           | $A = 183 x^{0.89}$                    |
| C <sub>17</sub> –C <sub>25</sub> |                                             |                                       | $A = 20 x^{0.90}$                           | $A = 57 x^{0.89}$                     |
| C <sub>25</sub> +                |                                             |                                       | $A = 11 x^{0.91}$                           | $A = 33 x^{0.89}$                     |
| H <sub>2</sub>                   | $A = 198 x^{0.992}$                         | $A = 614 x^{0.933}$                   |                                             |                                       |
| H <sub>2</sub> S                 | $A = 32 x^{1.00}$                           | $A = 52 x^{1.00}$                     |                                             |                                       |
| HF                               |                                             |                                       |                                             |                                       |
| Aromatics                        | $A = 121.39 x^{0.8911}$                     | $A = 359 x^{0.8821}$                  |                                             |                                       |
| Styrene                          | $A = 121.39 x^{0.8911}$                     | $A = 359 x^{0.8821}$                  |                                             |                                       |

Note: Shaded area represents cases in which equations are nonapplicable.

x = total release rate, lb/sec.

A = area, ft<sup>2</sup>.

<sup>a</sup>Not likely if process temperature is less than auto ignition temperature plus 80°F.

Table 7-9—Instantaneous Release Consequence Equations—Auto Ignition Not Likely<sup>a</sup>

| Material                         | Final Phase Gas                             |                                       | Final Phase Liquid                          |                                       |
|----------------------------------|---------------------------------------------|---------------------------------------|---------------------------------------------|---------------------------------------|
|                                  | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) |
| C <sub>1</sub> –C <sub>2</sub>   | $A = 41 x^{0.67}$                           | $A = 79 x^{0.67}$                     |                                             |                                       |
| C <sub>3</sub> –C <sub>4</sub>   | $A = 28 x^{0.72}$                           | $A = 57.7 x^{0.75}$                   |                                             |                                       |
| C <sub>5</sub>                   | $A = 13.4 x^{0.73}$                         | $A = 20.4 x^{0.76}$                   | $A = 1.49 x^{0.85}$                         | $A = 4.34 x^{0.85}$                   |
| C <sub>6</sub> –C <sub>8</sub>   | $A = 14 x^{0.67}$                           | $A = 26 x^{0.67}$                     | $A = 4.35 x^{0.78}$                         | $A = 12.7 x^{0.78}$                   |
| C <sub>9</sub> –C <sub>12</sub>  | $A = 7.1 x^{0.66}$                          | $A = 13 x^{0.66}$                     | $A = 3.3 x^{0.76}$                          | $A = 9.5 x^{0.76}$                    |
| C <sub>13</sub> –C <sub>16</sub> |                                             |                                       | $A = 0.46 x^{0.88}$                         | $A = 1.3 x^{0.88}$                    |
| C <sub>17</sub> –C <sub>25</sub> |                                             |                                       | $A = 0.11 x^{0.91}$                         | $A = 0.32 x^{0.91}$                   |
| C <sub>25</sub> +                |                                             |                                       | $A = 0.03 x^{0.99}$                         | $A = 0.081 x^{0.99}$                  |
| H <sub>2</sub>                   | $A = 545 x^{0.657}$                         | $A = 982 x^{0.652}$                   |                                             |                                       |
| H <sub>2</sub> S                 | $A = 148 x^{0.63}$                          | $A = 271 x^{0.63}$                    |                                             |                                       |
| HF                               |                                             |                                       |                                             |                                       |
| Aromatics                        | $A = 2.26 x^{0.8227}$                       | $A = 10.5 x^{0.7583}$                 |                                             |                                       |
| Styrene                          | $A = 2.26 x^{0.8227}$                       | $A = 10.5 x^{0.7583}$                 |                                             |                                       |

Note: Shaded area represents cases in which equations are nonapplicable.

x = total release mass, lb.

A = area, ft<sup>2</sup>.

<sup>a</sup>Not likely if process temperature is less than auto ignition temperature plus 80°F.



Table 7-10—Continuous Release Consequence Equations—Auto Ignition Likely<sup>a</sup>

| Material                         | Final Phase Gas                             |                                       | Final Phase Liquid                          |                                       |
|----------------------------------|---------------------------------------------|---------------------------------------|---------------------------------------------|---------------------------------------|
|                                  | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) |
| C <sub>1</sub> –C <sub>2</sub>   | $A = 280 x^{0.95}$                          | $A = 745 x^{0.92}$                    |                                             |                                       |
| C <sub>3</sub> –C <sub>4</sub>   | $A = 315 x^{1.00}$                          | $A = 837 x^{0.92}$                    |                                             |                                       |
| C <sub>5</sub>                   | $A = 304 x^{1.00}$                          | $A = 811 x^{1.00}$                    |                                             |                                       |
| C <sub>6</sub> –C <sub>8</sub>   | $A = 313 x^{1.00}$                          | $A = 828 x^{1.00}$                    | $A = 525 x^{0.95}$                          | $A = 1315 x^{0.92}$                   |
| C <sub>9</sub> –C <sub>12</sub>  | $A = 391 x^{0.95}$                          | $A = 981 x^{0.92}$                    | $A = 560 x^{0.95}$                          | $A = 1401 x^{0.92}$                   |
| C <sub>13</sub> –C <sub>16</sub> |                                             |                                       | $A = 1023 x^{0.92}$                         | $A = 2850 x^{0.90}$                   |
| C <sub>17</sub> –C <sub>25</sub> |                                             |                                       | $A = 861 x^{0.92}$                          | $A = 2420 x^{0.90}$                   |
| C <sub>25</sub> +                |                                             |                                       | $A = 544 x^{0.90}$                          | $A = 1604 x^{0.90}$                   |
| H <sub>2</sub>                   | $A = 1146 x^{1.00}$                         | $A = 3072 x^{1.00}$                   |                                             |                                       |
| H <sub>2</sub> S                 | $A = 203 x^{0.89}$                          | $A = 375 x^{0.94}$                    |                                             |                                       |
| HF                               |                                             |                                       |                                             |                                       |
| Aromatics                        |                                             |                                       |                                             |                                       |
| Styrene                          |                                             |                                       |                                             |                                       |

Shaded area represents cases in which equations are nonapplicable.

x = total release rate, lb/sec.

A = area, ft<sup>2</sup>.

<sup>a</sup>Must be processed at least 80°F above auto ignition temperature.

Table 7-11—Instantaneous Release Consequence Equations—Auto Ignition Likely<sup>a</sup>

| Material                         | Final Phase Gas                             |                                       | Final Phase Liquid                          |                                       |
|----------------------------------|---------------------------------------------|---------------------------------------|---------------------------------------------|---------------------------------------|
|                                  | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) |
| C <sub>1</sub> –C <sub>2</sub>   | $A = 1079 x^{0.62}$                         | $A = 3100 x^{0.63}$                   |                                             |                                       |
| C <sub>3</sub> –C <sub>4</sub>   | $A = 523 x^{0.63}$                          | $A = 1768 x^{0.63}$                   |                                             |                                       |
| C <sub>5</sub>                   | $A = 275 x^{0.61}$                          | $A = 959 x^{0.63}$                    |                                             |                                       |
| C <sub>6</sub> –C <sub>8</sub>   | $A = 76 x^{0.61}$                           | $A = 962 x^{0.63}$                    |                                             |                                       |
| C <sub>9</sub> –C <sub>12</sub>  | $A = 281 x^{0.61}$                          | $A = 988 x^{0.63}$                    | $A = 6.0 x^{0.53}$                          | $A = 20 x^{0.54}$                     |
| C <sub>13</sub> –C <sub>16</sub> |                                             |                                       | $A = 9.2 x^{0.88}$                          | $A = 26 x^{0.88}$                     |
| C <sub>17</sub> –C <sub>25</sub> |                                             |                                       | $A = 5.6 x^{0.91}$                          | $A = 16 x^{0.91}$                     |
| C <sub>25</sub> +                |                                             |                                       | $A = 1.4 x^{0.99}$                          | $A = 4.1 x^{0.99}$                    |
| H <sub>2</sub>                   | $A = 1430 x^{0.618}$                        | $A = 4193 x^{0.621}$                  |                                             |                                       |
| H <sub>2</sub> S                 | $A = 357 x^{0.61}$                          | $A = 1253 x^{0.63}$                   |                                             |                                       |
| HF                               |                                             |                                       |                                             |                                       |
| Aromatics                        |                                             |                                       |                                             |                                       |
| Styrene                          |                                             |                                       |                                             |                                       |

Shaded area represents cases in which equations are nonapplicable.

x = total release mass, lb.

A = area, ft<sup>2</sup>.

<sup>a</sup>Must be processed at least 80°F above auto ignition temperature.

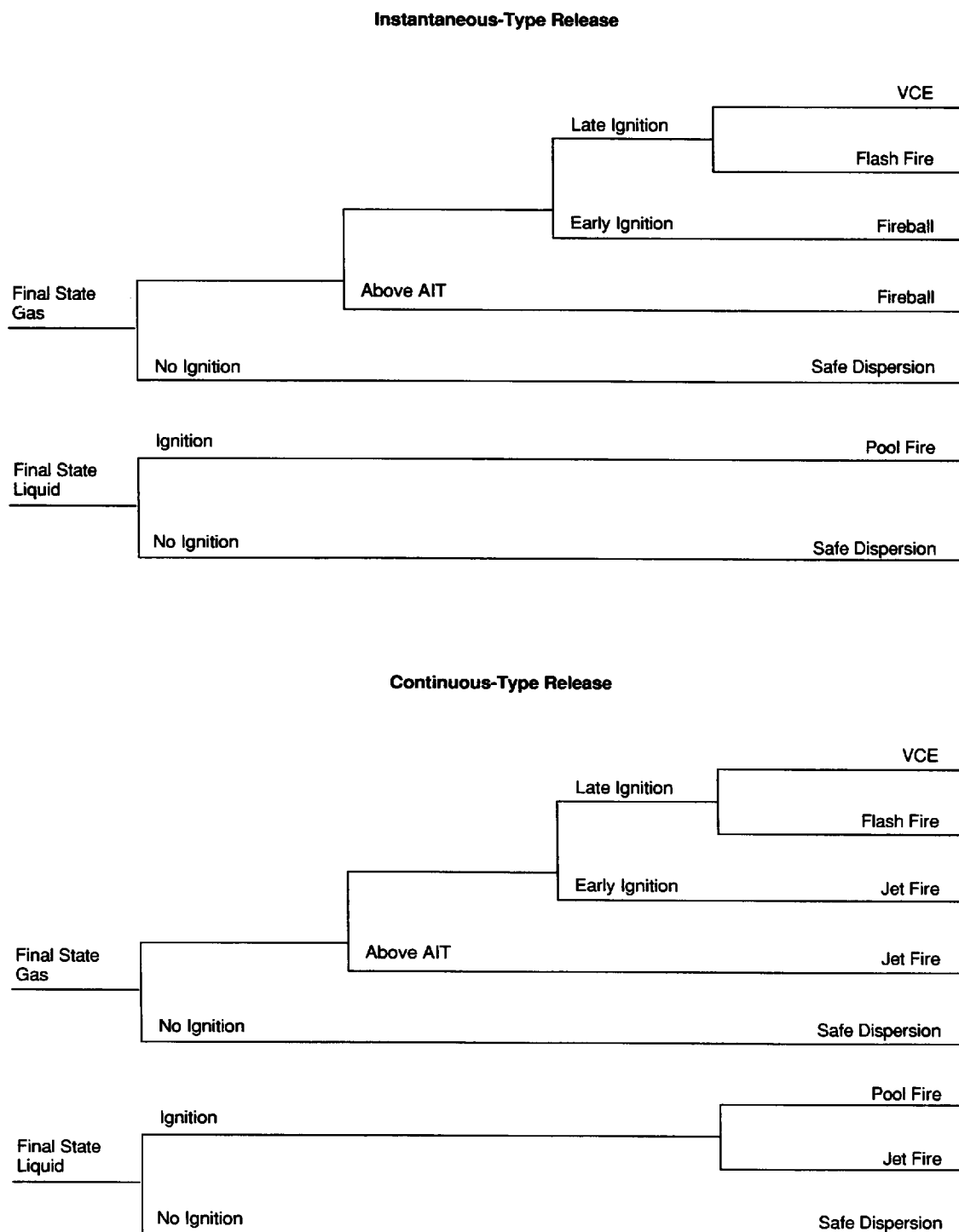


Figure 7-3—RBI Release Event Trees

Table 7-12—Specific Event Probabilities—Continuous Release Auto Ignition Likely<sup>a</sup>

## Final State Liquid—Processed Above AIT

| Fluid                            | Probabilities of Outcomes |     |          |            |          |           |
|----------------------------------|---------------------------|-----|----------|------------|----------|-----------|
|                                  | Ignition                  | VCE | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>1</sub> –C <sub>2</sub>   |                           |     |          |            |          |           |
| C <sub>3</sub> –C <sub>4</sub>   |                           |     |          |            |          |           |
| C <sub>5</sub>                   |                           |     |          |            |          |           |
| C <sub>6</sub> –C <sub>8</sub>   | 1                         |     |          |            | 1        |           |
| C <sub>9</sub> –C <sub>12</sub>  | 1                         |     |          |            | 1        |           |
| C <sub>13</sub> –C <sub>16</sub> | 1                         |     |          |            | 0.5      | 0.5       |
| C <sub>17</sub> –C <sub>25</sub> | 1                         |     |          |            | 0.5      | 0.5       |
| C <sub>25</sub> +                |                           |     |          |            |          | 1         |
| H <sub>2</sub>                   |                           |     |          |            |          |           |
| H <sub>2</sub> S                 |                           |     |          |            |          |           |

## Final State Gas - Processed Above AIT

| Fluid                            | Probabilities of Outcomes |     |          |            |          |           |
|----------------------------------|---------------------------|-----|----------|------------|----------|-----------|
|                                  | Ignition                  | VCE | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>1</sub> –C <sub>2</sub>   | 0.7                       |     |          |            | 0.7      |           |
| C <sub>3</sub> –C <sub>4</sub>   | 0.7                       |     |          |            | 0.7      |           |
| C <sub>5</sub>                   | 0.7                       |     |          |            | 0.7      |           |
| C <sub>6</sub> –C <sub>8</sub>   | 0.7                       |     |          |            | 0.7      |           |
| C <sub>9</sub> –C <sub>12</sub>  | 0.7                       |     |          |            | 0.7      |           |
| C <sub>13</sub> –C <sub>16</sub> |                           |     |          |            |          |           |
| C <sub>17</sub> –C <sub>25</sub> |                           |     |          |            |          |           |
| C <sub>25</sub> +                |                           |     |          |            |          |           |
| H <sub>2</sub>                   | 0.9                       |     |          |            | 0.9      |           |
| H <sub>2</sub> S                 | 0.9                       |     |          |            | 0.9      |           |

Note: Shaded areas represent outcomes that are not physically possible

<sup>a</sup>Must be processed at least 80°F above AIT

event trees also are used to show how various individual event probabilities should be combined to calculate the probability for the chain of events.

For a given release type, the factor that defines the outcome of the release of flammable material is the probability and timing of ignition. The three possibilities depicted in the outcome event trees were: no ignition, early ignition, and late ignition.

The event tree outcome probabilities for all release types are presented in Tables 7-12 and 7-13 according to the release type and material. Each row within the tables contains probabilities for each potential outcome, according to material. Event trees developed for standard risk analyses were used to develop the relative outcome probabilities. Ignition probabilities were based on previously developed correlations. In general, ignition probabilities are found as a function of the following parameters for the fluid:

- Auto Ignition Temperature (AIT).
- Flash temperature.
- NFPA Flammability Index.

- Flammability Range (difference between upper and lower flammability limits).

If a fluid is released at a temperature well above its auto ignition temperature (at least 80°F above), ignition probabilities will change dramatically. These are reflected in Tables 7-12 and 7-13.

#### b. Step 2—Calculating Consequences for Each Outcome

To calculate the consequences of a particular event, it is first necessary to define the threshold levels needed to cause a specific consequence. These threshold levels are referred to as impact criteria.

RBI uses 2 sets of impact criteria to determine the size of the area affected: equipment damage and personnel fatality.

#### Equipment Damage Criteria:

- Explosion Overpressure—5 psig.
- Thermal Radiation—12,000 BTU/hr-ft<sup>2</sup> (jet fire and pool fire).
- Flash Fire—25% of the area within the lower flammability limits (LFL) of the cloud when ignited.

Table 7-13—Specific Event Probabilities—Instantaneous Release Auto Ignition Likely<sup>a</sup>

| Final State Liquid—Processed Above AIT |                           |     |          |            |          |           |
|----------------------------------------|---------------------------|-----|----------|------------|----------|-----------|
| Fluid                                  | Probabilities of Outcomes |     |          |            |          |           |
|                                        | Ignition                  | VCE | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>1</sub> –C <sub>2</sub>         | 0.7                       |     | 0.7      |            |          |           |
| C <sub>3</sub> –C <sub>4</sub>         | 0.7                       |     | 0.7      |            |          |           |
| C <sub>5</sub>                         | 0.7                       |     | 0.7      |            |          |           |
| C <sub>6</sub> –C <sub>8</sub>         | 0.7                       |     | 0.7      |            |          |           |
| C <sub>9</sub> –C <sub>12</sub>        | 0.7                       |     | 0.7      |            |          |           |
| C <sub>13</sub> –C <sub>16</sub>       |                           |     |          |            |          |           |
| C <sub>17</sub> –C <sub>25</sub>       |                           |     |          |            |          |           |
| C <sub>25</sub> +                      |                           |     |          |            |          |           |
| H <sub>2</sub>                         | 0.9                       |     | 0.9      |            |          |           |
| H <sub>2</sub> S                       | 0.9                       |     | 0.9      |            |          |           |

| Fluid                            | Probabilities of Outcomes |     |          |            |          |           |
|----------------------------------|---------------------------|-----|----------|------------|----------|-----------|
|                                  | Ignition                  | VCE | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>1</sub> –C <sub>2</sub>   | 0.7                       |     | 0.7      |            |          |           |
| C <sub>3</sub> –C <sub>4</sub>   | 0.7                       |     | 0.7      |            |          |           |
| C <sub>5</sub>                   | 0.7                       |     | 0.7      |            |          |           |
| C <sub>6</sub> –C <sub>8</sub>   | 0.7                       |     | 0.7      |            |          |           |
| C <sub>9</sub> –C <sub>12</sub>  | 0.7                       |     | 0.7      |            |          |           |
| C <sub>13</sub> –C <sub>16</sub> |                           |     |          |            |          |           |
| C <sub>17</sub> –C <sub>25</sub> |                           |     |          |            |          |           |
| C <sub>25</sub> +                |                           |     |          |            |          |           |
| H <sub>2</sub>                   | 0.9                       |     | 0.9      |            |          |           |
| H <sub>2</sub> S                 | 0.9                       |     | 0.9      |            |          |           |

Note: Shaded areas represent outcomes that are not physically possible.

<sup>a</sup>Must be processed at least 80°F above AIT.

#### Personnel Fatality Criteria:

- Explosion Overpressure—5 psig.
- Thermal Radiation—4,000 BTU/hr-ft<sup>2</sup> (jet fire, fireball, and pool fire).
- Flash Fire—the LFL limits of the cloud when ignited.

A set of representative materials was run through the hazards analysis screening program to determine the consequence areas for all potential outcomes. The consequence areas were then plotted against the release rate or mass to generate graphs. When plotted on a log/log scale, the consequence curves form straight lines that can be fit to an equation relating consequence area to the release rate or mass.

The consequence equations are presented in the following form:

$$A = a x^b \quad (7.5)$$

where

$A$  = consequence area (ft<sup>2</sup>),

$a, b$  = material and consequence dependent constants,

$x$  = release rate (lb/sec for continuous) or release mass (lb for instantaneous).

The consequences of releases of flammable materials are not strongly dependent on the duration of the release, since most fluids reach a steady state size or "footprint" within a short period of time when dispersed in the atmosphere. The only exception to this generalization is a pool fire resulting from the continuous release of a liquid. If flammable liquids are released in a continuous manner, the consequences associated with a pool fire will depend on the duration and the total mass of the release.

For pool fires, the RBI method assumes a dike size of 100 feet by 100 feet (10,000 square feet) and estimates the flammable consequences due to a pool fire of that size.

#### Step 3—Calculation of the Combined Consequence Area

An equation that represents a single consequence area for the combination of possible outcomes can be derived for each of the four release types, final phase cases. The combined consequence area is determined by a two-step process:

Table 7-14—Specific Event Probabilities—Continuous Release Auto Ignition Not Likely<sup>a</sup>

## Final State Liquid—Processed Below AIT

| Fluid                            | Probabilities of Outcomes |     |          |            |          |           |
|----------------------------------|---------------------------|-----|----------|------------|----------|-----------|
|                                  | Ignition                  | VCE | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>1</sub> –C <sub>2</sub>   |                           |     |          |            |          |           |
| C <sub>3</sub> –C <sub>4</sub>   | 0.1                       |     |          |            |          |           |
| C <sub>5</sub>                   | 0.1                       |     |          |            | 0.02     | 0.08      |
| C <sub>6</sub> –C <sub>8</sub>   | 0.1                       |     |          |            | 0.02     | 0.08      |
| C <sub>9</sub> –C <sub>12</sub>  | 0.05                      |     |          |            | 0.01     | 0.04      |
| C <sub>13</sub> –C <sub>16</sub> | 0.05                      |     |          |            | 0.01     | 0.04      |
| C <sub>17</sub> –C <sub>25</sub> | 0.02                      |     |          |            | 0.005    | 0.015     |
| C <sub>25</sub> + 0.02           |                           |     |          |            | 0.005    | 0.015     |
| H <sub>2</sub>                   |                           |     |          |            |          |           |
| H <sub>2</sub> S                 |                           |     |          |            |          |           |

## Final State Gas—Processed Below AIT

| Fluid                            | Probabilities of Outcome |      |          |            |          |           |
|----------------------------------|--------------------------|------|----------|------------|----------|-----------|
|                                  | Ignition                 | VCE  | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>1</sub> –C <sub>2</sub>   | 0.2                      | 0.04 |          | 0.06       | 0.1      |           |
| C <sub>3</sub> –C <sub>4</sub>   | 0.1                      | 0.03 |          | 0.02       | 0.05     |           |
| C <sub>5</sub>                   | 0.1                      | 0.03 |          | 0.02       | 0.05     |           |
| C <sub>6</sub> –C <sub>8</sub>   | 0.1                      | 0.03 |          | 0.02       | 0.05     |           |
| C <sub>9</sub> –C <sub>12</sub>  | 0.05                     | 0.01 |          | 0.02       | 0.02     |           |
| C <sub>13</sub> –C <sub>16</sub> |                          |      |          |            |          |           |
| C <sub>17</sub> –C <sub>25</sub> |                          |      |          |            |          |           |
| C <sub>25</sub> + 0.02           |                          |      |          |            |          |           |
| H <sub>2</sub>                   | 0.9                      | 0.4  |          | 0.4        | 0.1      |           |
| H <sub>2</sub> S                 | 0.9                      | 0.4  |          | 0.4        | 0.2      |           |

Note: Shaded areas represent outcomes that are not physically possible.

<sup>a</sup>Not likely if process temperature is less than auto ignition temperature plus 80°F.

1. Multiply the consequence area for each outcome (computed from Equation 7.5) by the associated event tree probabilities (taken from Table 7-12 or 7-13). If the impact criterion uses only a portion of the consequence area (for instance, flash fires use only 25% of the area within the LFL for equipment damage) include this in the probability equation.

2. Sum all of the consequence-probability products found in Step 1.

The equation that summarizes the result of the process is as follows:

$$A_{comb} = P_1 A_1 + P_2 A_2 + \dots + P_i A_i \quad (7.6)$$

where

$A_{comb}$  = combined consequence area (ft<sup>2</sup>),

$P_i$  = specific event probability, from Table 7-8 or 7-9,

$A_i$  = individual outcome consequence area, from Equation 8.5 (ft<sup>2</sup>).

The procedure for combining consequence equations for all of the potential outcomes was performed for a set of representative materials. The results are presented in Table 7-14 for continuous releases and Table 7-15 for instantaneous releases.

### 7.9.3.2 Adjustments to Release Magnitudes for Mitigation Systems

The adjustments to release characteristics based on detection, isolation and mitigation systems are provided in Table 7-16. These values are based on engineering judgment, utilizing experience in evaluating mitigation measures in quantitative risk analyses. See 7.8.2 for a discussion of the rating process.

Table 7-15—Specific Event Probabilities—Instantaneous Release Auto Ignition Not Likely<sup>a</sup>

| Final State Liquid—Processed Below AIT |                           |      |          |            |          |           |
|----------------------------------------|---------------------------|------|----------|------------|----------|-----------|
| Fluid                                  | Probabilities of Outcomes |      |          |            |          |           |
|                                        | Ignition                  | VCE  | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>1</sub> – C <sub>2</sub>        |                           |      |          |            |          |           |
| C <sub>3</sub> – C <sub>4</sub>        |                           |      |          |            |          |           |
| C <sub>5</sub>                         | 0.1                       |      |          |            |          | 0.1       |
| C <sub>6</sub> – C <sub>8</sub>        | 0.1                       |      |          |            |          | 0.1       |
| C <sub>9</sub> – C <sub>12</sub>       | 0.05                      |      |          |            |          | 0.05      |
| C <sub>13</sub> – C <sub>16</sub>      | 0.05                      |      |          |            |          | 0.05      |
| C <sub>17</sub> – C <sub>25</sub>      | 0.02                      |      |          |            |          | 0.02      |
| C <sub>25</sub> +                      | 0.02                      |      |          |            |          | 0.02      |
| H <sub>2</sub>                         |                           |      |          |            |          |           |
| H <sub>2</sub> S                       |                           |      |          |            |          |           |
| Fluid                                  | Ignition                  | VCE  | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>1</sub> – C <sub>2</sub>        | 0.2                       | 0.04 | 0.01     | 0.15       |          |           |
| C <sub>3</sub> – C <sub>4</sub>        | 0.1                       | 0.02 | 0.01     | 0.07       |          |           |
| C <sub>5</sub>                         | 0.1                       | 0.02 | 0.01     | 0.07       |          |           |
| C <sub>6</sub> – C <sub>8</sub>        | 0.1                       | 0.02 | 0.01     | 0.07       |          |           |
| C <sub>9</sub> – C <sub>12</sub>       | 0.04                      | 0.01 | 0.005    | 0.025      |          |           |
| C <sub>13</sub> – C <sub>16</sub>      |                           |      |          |            |          |           |
| C <sub>17</sub> – C <sub>25</sub>      |                           |      |          |            |          |           |
| C <sub>25</sub> +                      |                           |      |          |            |          |           |
| H <sub>2</sub>                         | 0.9                       | 0.4  | 0.1      | 0.4        |          |           |
| H <sub>2</sub> S                       | 0.9                       | 0.4  | 0.1      | 0.4        |          |           |

Note: Shaded areas represent outcomes that are not physically possible.

<sup>a</sup>Not likely if process temperature is less than auto ignition temperature plus 80°F.

Table 7-16—Adjustments to Flammable Consequences for Mitigation Systems

| Response System Ratings                                             |           |                                    |
|---------------------------------------------------------------------|-----------|------------------------------------|
| Detection                                                           | Isolation | Consequence Adjustment             |
| A                                                                   | A         | Reduce release rate or mass by 25% |
| A                                                                   | B         | Reduce release rate or mass by 20% |
| A or B                                                              | C         | Reduce release rate or mass by 10% |
| B                                                                   | B         | Reduce release rate or mass by 15% |
| C                                                                   | C         | No adjustment to consequences      |
| Mitigation System                                                   |           | Consequence Adjustment             |
| Inventory blowdown, coupled with isolation system rated B or higher |           | Reduce release rate or mass by 25% |
| Fire water deluge system and monitors                               |           | Reduce consequence area by 20%     |
| Fire water monitors only                                            |           | Reduce consequence area by 5%      |
| Foam spray system                                                   |           | Reduce consequence area by 15%     |

### 7.9.3.3 Assumptions and Limitations

The consequence modeling procedure for RBI is a greatly simplified approach to a relatively complex discipline. Because of the level of simplification, a large number of assumptions are implicit in the procedure in addition to the assumptions that would be part of a more in-depth analysis. This section is intended to highlight a few of the more important assumptions related to the simplified approach, but does not attempt a comprehensive discussion.

- The consequence area does not reflect where the damage occurs. Jet and pool fires tend to have damage areas localized around the point of the release, but vapor cloud explosions and flash fires may result in damage far from the release point.
- The use of a fixed set of conditions for meteorology and release orientations is a great simplification over detailed consequence calculations because these factors can have a significant impact on the results.
- The use of the standardized event trees for consequence outcomes and ignition probabilities is a limitation of the RBI method. These factors are very site-specific, and the user needs to realize that they are chosen to reflect representative conditions for the petrochemical industry.

### 7.9.4 Toxic Consequences

Toxic fluids are similar to flammables in that not all toxic releases result in a single type of effect. By themselves, hydrogen fluoride (HF), ammonia, and chlorine pose only a toxic hazard. On the other hand, some toxic materials such as hydrogen sulfide ( $H_2S$ ) are both toxic and flammable. However, any toxic material, when mixed with hydrocarbons, can pose flammable and toxic hazards. RBI allows for each of these possibilities.

RBI evaluates the risks associated with four toxic materials that typically contribute to toxic risks for a refinery: hydrogen fluoride (HF), hydrogen sulfide ( $H_2S$ ), ammonia ( $NH_3$ ), and chlorine (Cl). The same approach can be used to evaluate other toxic materials.

#### 7.9.4.1 Scenario Development

The selection of scenarios follows the methodology presented in 7.2, using 1/4-inch, 1-inch, 4-inch and rupture hole sizes. The release duration is provided by the analyst, and depends upon the circumstances associated with the release. The release rate (either liquid or vapor) is then calculated as in 7.4.

#### 7.9.4.2 Material Concentration Cut-Off

As a general rule, it is not necessary to evaluate a toxic release if the concentration of the material within the equipment item is at or below the IDLH (Immediately Dangerous to Life or Health) value. For HF, this is 30 ppm, for  $H_2S$  this is 300 ppm, for  $NH_3$ , it is 300 and for Cl it is 30.

### 7.9.4.3 Representative Materials

If the material being released is not a pure toxic material, a representative material should be used for discharge rate modeling purposes. The representative material should be selected based upon the average boiling point, density, and molecular weight of the mixture. Since HF is a flame suppressant, flammable consequences can be ignored for HF concentrations greater than 65 mol%.

#### 7.9.4.4 Release Rate/Mass

**7.9.4.4.1** For the most part, HF is stored, transferred, and processed in liquid form. However, the toxic impact associated with a release of liquid HF to the atmosphere is due to the dispersion of the toxic vapor cloud. A toxic vapor cloud of HF can be produced by flashing of the liquid upon release or evaporation from a liquid pool. For RBI, the initial state of HF is assumed to be liquid; the models for calculating the toxic impact areas for HF liquid releases take into account the possibility of flashing and pool evaporation. For HF releases, RBI uses the following guidelines:

- If the released material contains HF as a component in a mixture, the mass fraction of HF is obtained, and
- The liquid rate (or mass) of only the HF component is used to calculate the toxic impact area.

**7.9.4.4.2** Hydrogen sulfide, due to its low boiling point, is processed as a vapor or, when processed under high pressures, quickly flashes upon release. In either case, the release of  $H_2S$  to the atmosphere results in the quick formation of a toxic vapor cloud. For  $H_2S$  releases, RBI uses the following guidelines:

- If the released material contains  $H_2S$  as a component in a mixture, the mass fraction of  $H_2S$  is obtained, and
- If the initial state of the material is a vapor, the mass fraction of  $H_2S$  is used to obtain the vapor discharge rate (or mass) of only  $H_2S$ ; this rate (or mass) is used to determine the impact area, or
- If the initial state of the material is a liquid, the mass fraction of  $H_2S$  is used to obtain the vapor flash rate (or mass) of only the  $H_2S$ ; this rate (or mass) is used to determine the impact area.

**7.9.4.4.3** For continuous releases, the discharge rate should be calculated as in 7.4. RBI uses a simplified approach for modeling releases of mixtures. If a release material is a mixture, the resulting toxic material release rate should then be calculated by multiplying the mass fraction of the toxic component by the previously-calculated discharge rate. For example, if the initial phase of a material being released is 1 wt%  $H_2S$  in gas oil, the material has the potential for both toxic and flammable outcomes from the vapor, and flammable outcomes from the liquid. Therefore, the following procedure is followed, using  $C_{17}$  as the representative material:

- Calculate the liquid discharge rate for  $C_{17}$  as described in 7.4.

b. When estimating flammable consequences, calculate the potential flammable consequence areas as in 7.8.1 and take the worst case between:

1. The flammable effects of  $C_{17}$  using 100% of the release rate
2. The flammable effects of  $H_2S$  based on 1% of the release rate

c. Calculate the toxic effects of  $H_2S$ , using 1% of the release rate.

For instantaneous releases, use the above procedure, substituting inventory for release rate.

#### 7.9.4.5 Release Duration

**7.9.4.5.1** The potential toxic consequence in RBI is estimated using both the release duration and release rate, whereas the flammable impact in RBI relies on just the release rate. The duration of a release depends on the following:

- a. The inventory in the equipment item and connected systems.
- b. Time to detect and isolate.
- c. Any response measures that may be taken.

**7.9.4.5.2** For RBI, the maximum release duration is set at one hour, for the following two reasons:

- a. It is expected that the plant's emergency response personnel will employ a shutdown procedure and initiate a combination of mitigation measures to limit the duration of a release.
- b. The HF toxicity data used in estimating the toxic dose effect are based on animal tests ranging from 5 minutes to 60 minutes in duration.

**7.9.4.5.3** As explained in 7.5, release duration can be estimated as the inventory in the system divided by the initial release rate. While the calculated duration may exceed one hour, there may be systems in place that will significantly shorten this time, such as isolation valves and rapid-acting leak detection systems. Times should be determined on a case-by-case basis. An effective release duration should be calculated as the minimum of:

- a. One hour.
- b. Inventory divided by release rate.
- c. Values listed in Table 7-7 (release duration based on detection and isolation systems ratings), plus the time required for the isolated area to deinventory through the leak.

#### 7.9.4.6 Toxic Impact Criteria

The toxic impact is a function of two components: exposure time and concentration. These two components combine to result in an exposure that is referred to as the toxic dose.

In RBI, the degree of injury from a toxic release is directly related to the toxic dose. RBI relates dose to injury using a probit. For toxic vapor exposure, the probit (a shortened form of probability unit) is represented as follows:

$$Pr = A + B \ln(C^N t) \quad (7.7)$$

where

$Pr$  = a measure of the percentage of the population that sustains a certain level of harm,

$C$  = concentration (ppm),

$t$  = exposure duration (minutes),

$A, B, N$  = mathematical constants used to formulate the probit equation, each toxic fluid has its own  $A$ ,  $B$ , and  $N$ .

RBI uses a single fixed probability of fatality (50% probability of fatality) to determine the toxic impact. This level corresponds to a probit value of 5.0.

#### 7.9.5 Consequence Estimation

A consequence analysis tool was used for a range of release rates and durations to obtain graphs of toxic consequence areas. Release durations of instantaneous (less than 3 minutes), 5 minutes (300 sec), 10 minutes (600 sec), 20 minutes (1200 sec), 40 minutes (2400 sec), and 1 hour (3600 sec) were evaluated to obtain toxic consequence areas for varying release rates.

##### 7.9.5.1 Consequence Area

The cloud footprint for a theoretical continuous release is roughly the shape of an ellipse, as shown in Figure 7-4. Hence, the area the cloud covers is somewhat conservatively assumed to be an ellipse and is calculated using the formula for an ellipse area:

$$\text{Area} = \pi ab \quad (7.8)$$

$a$  =  $1/2$  of the cloud width (minor axis), taken at its largest point (within the 50% probability of fatality dose level),

$b$  =  $1/2$  of the downwind dispersion distance (major axis), taken at the 50% probability of fatality dose level,

$\pi$  = 3.14157.

The consequence area results for continuous releases of toxics are presented in Figures 7-5 and 7-6.

For instantaneous releases, the dispersion of the cloud over time is depicted in Figure 7-7. The area covered by the cloud is conservatively assumed to be an ellipse, except that the  $x$ -distance ( $a$ ) is simply  $1/2$  of the maximum cloud width as determined from the dispersion results. The consequence area curves, as a function of the release mass, are presented in Figure 7-8 for instantaneous releases of toxics.



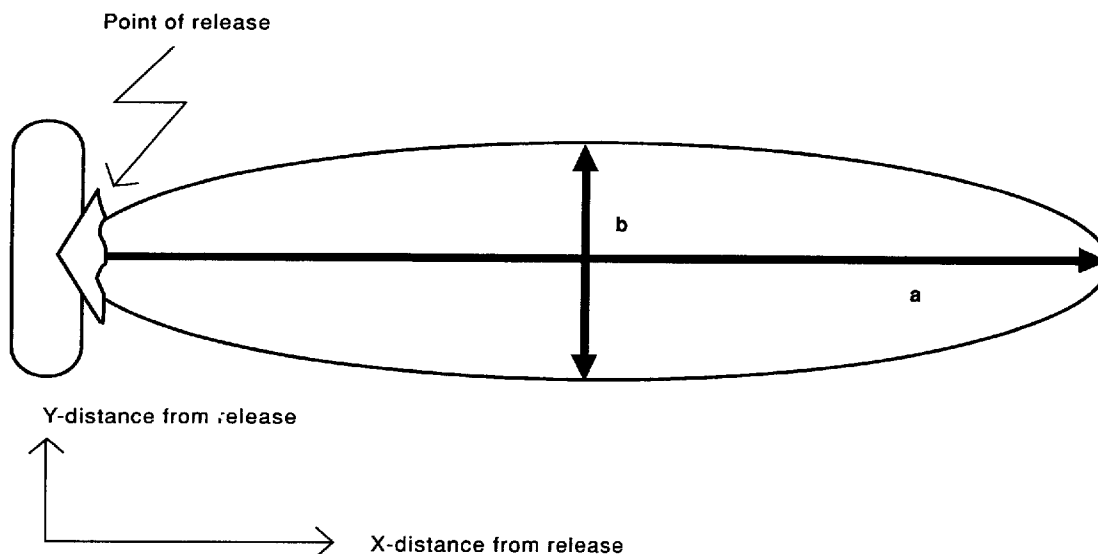


Figure 7-4—Top View of Toxic Plume for a Continuous Release

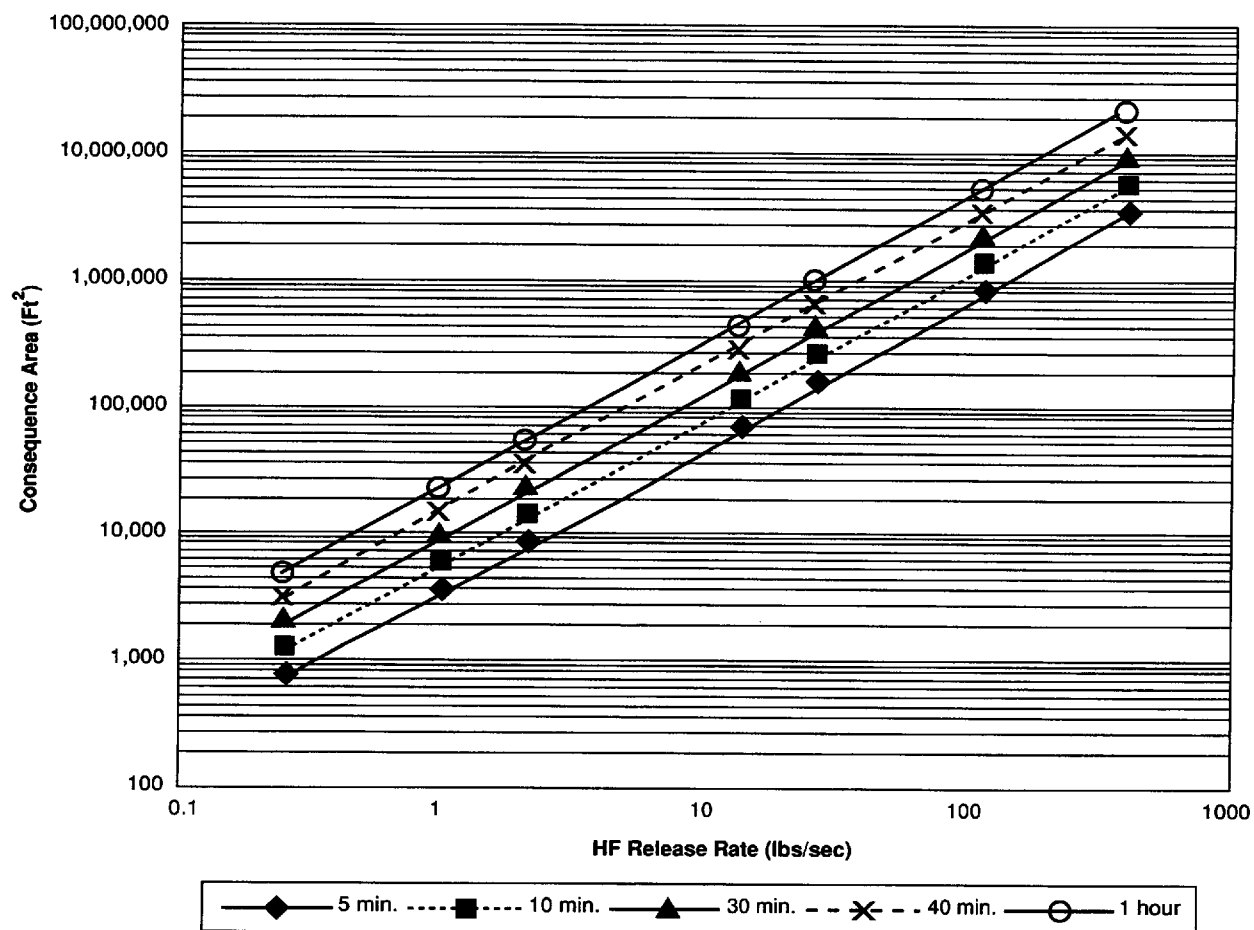


Figure 7-5—Consequence Area for Continuous HF Releases

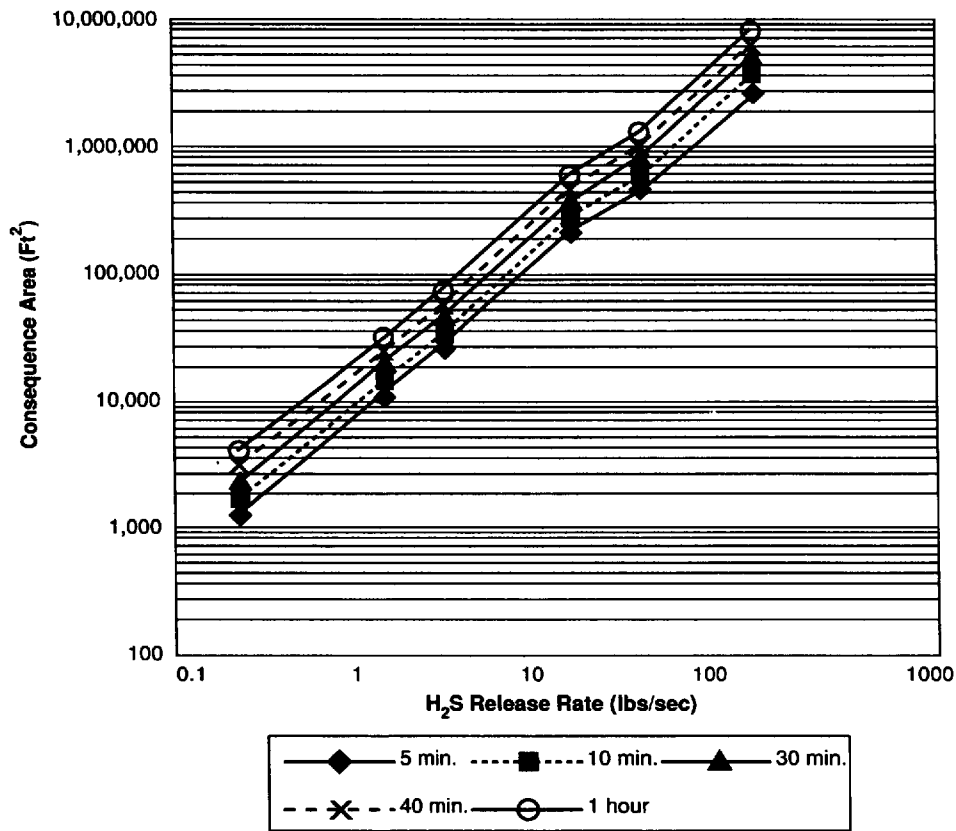


Figure 7-6—Consequence Area for Continuous H<sub>2</sub>S Releases

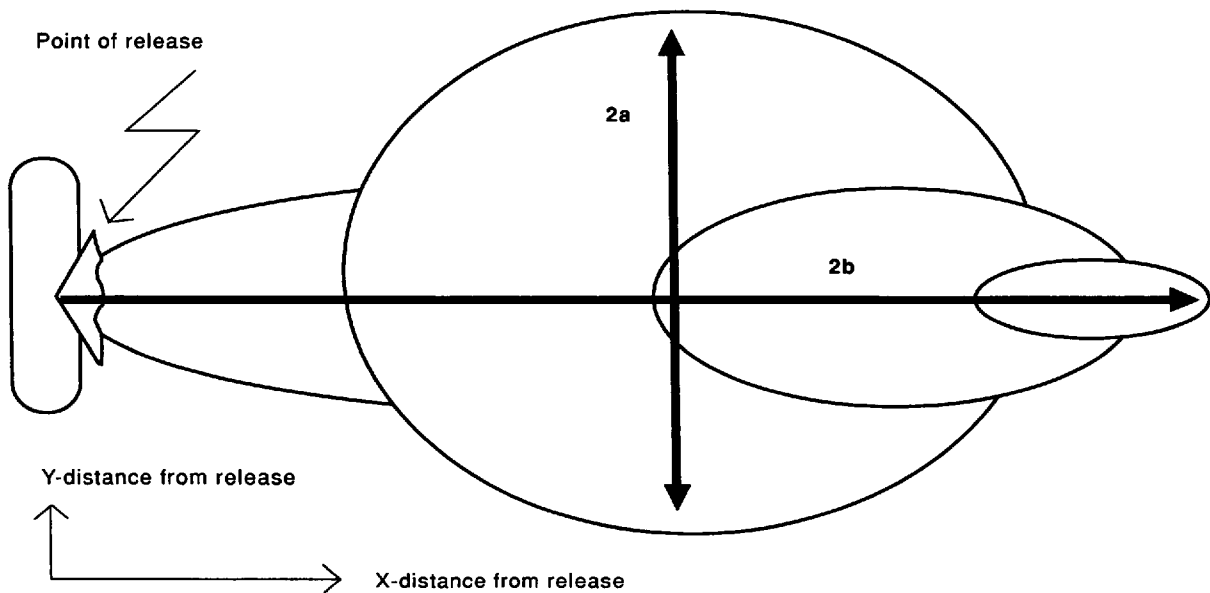


Figure 7-7—Top View of Toxic Plume for an Instantaneous Release

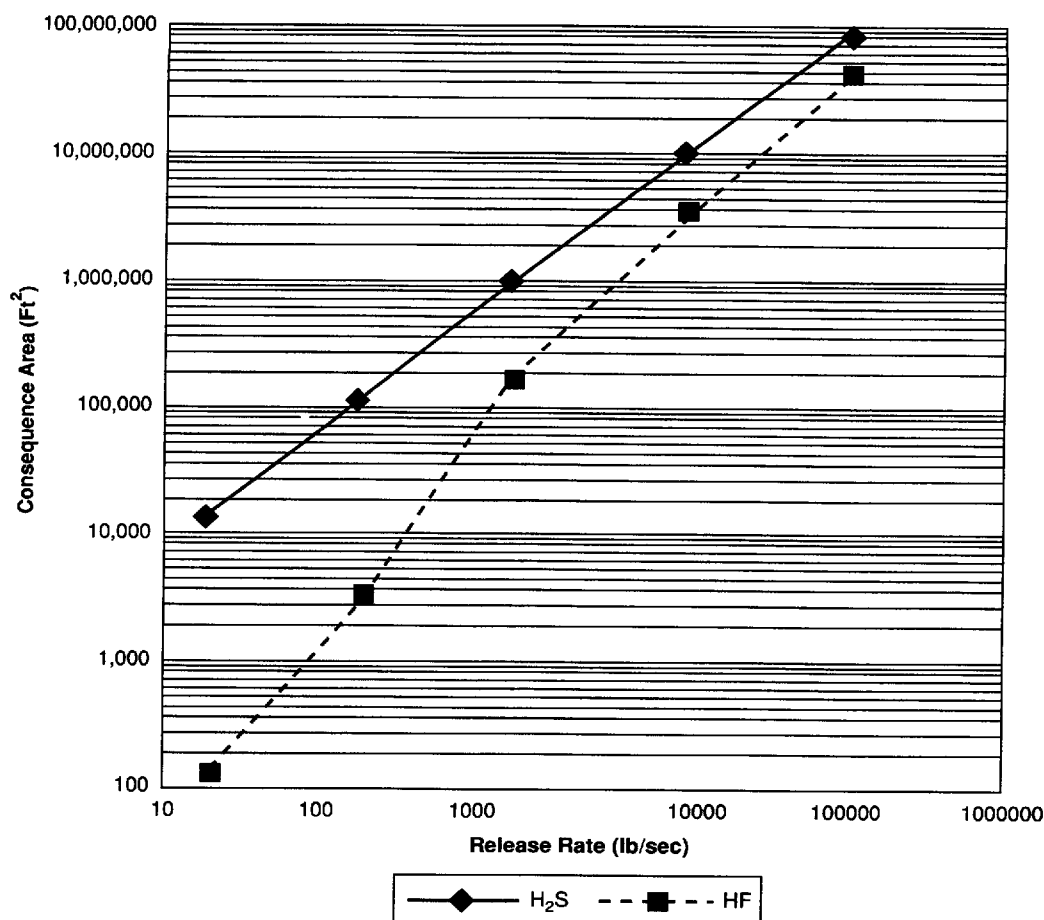


Figure 7-8—Consequence Area for Instantaneous HF and H<sub>2</sub>S Releases

### 7.9.5.2 Outcome Probabilities

In the event the release can involve both toxic and flammable outcomes, it is assumed that either the flammable outcome consumes the toxic material, or the toxic materials are dispersed and flammable materials have insignificant consequences. In this case, the probability for the toxic event is the remaining nonignition frequency for the event (i.e., the probability of "safe dispersion," as explained in 5.2.2.1).

### 7.9.5.3 Calculation of the Combined Consequences for Toxic Releases

Toxic consequence results can be averaged using the same methods presented in 7.8.1, using Equation 7.6. As with the flammable results, consequence areas for the individual toxic events are multiplied by their corresponding event probabilities. The result is a single consequence area that represents an average of all possible outcomes for the equipment item. This procedure is done for each equipment item.

### 7.9.5.4 Ammonia/Chlorine Modeling

A saturated liquid at ambient temperature (75°F) was used, with liquid being released from the tank. The tank head was set at 10 feet.

To determine an equation for the effect area of a continuous release of ammonia and chlorine, four release cases (0.25 in., 1 in., 4 in., and 16 in.) were run for various release durations (10, 30, and 60 minutes). A plot of the release rate vs. the consequence area when the probit equals five is shown in Figures 7-9 and 7-10.

The relationship between the release rate and the area followed the following formula:

$$A = c x^b$$

where

$A$  = the effect area in square feet,

$x$  = the release mass in lbs.

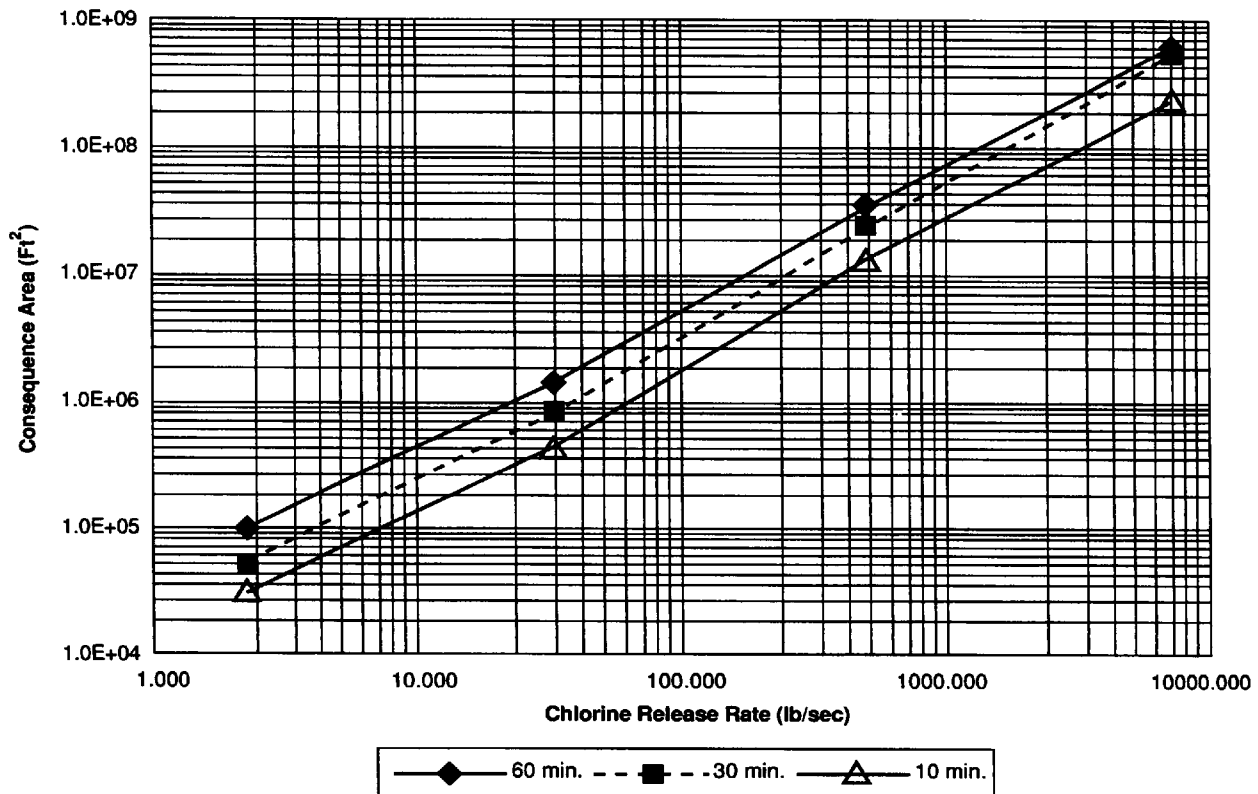


Figure 7-9—Continuous Chlorine Release

The constants (c and b) are listed in Table 7-17 for the different cases.

For instantaneous release cases, four masses of ammonia and chlorine were modeled (10, 100, 1,000, and 10,000 lb), and the relationship between inventory mass and are to prohibit five was found to be:

$$A = 14.97 x^{1.177} \text{ for chlorine, and}$$

$$A = 14.17 x^{0.9011} \text{ for ammonia.}$$

Plots of the instantaneous release rates vs. the consequence area are shown in Figures 7-11 and 7-12.

### 7.9.6 Consequences of Steam Leaks

Steam represents a hazard to personnel who are exposed to steam at high temperatures. In general, steam is at 212°F immediately after exiting a hole in an equipment item. Within a few feet, depending upon its pressure, steam will begin to mix with air, cool and condense. At a concentration of about 20%, the steam/air mixture cools to about 140°F. The approach used here is to assume that injury occurs only above 140°F. 140°F was selected as the threshold for injury to personnel, as this is the temperature above which OSHA requires that hot surfaces be insulated to protect against personnel burns.

Table 7-17—Continuous Release Durations for Chlorine and Ammonia

| Chemical | Release Duration | c      | b    |
|----------|------------------|--------|------|
| Chlorine | 60 minute        | 46,563 | 1.01 |
|          | 30 minute        | 27,711 | 1.10 |
|          | 10 minute        | 15,147 | 1.10 |
| Ammonia  | 60 minute        | 11,049 | 1.16 |
|          | 30 minute        | 7,852  | 1.16 |
|          | 10 minute        | 2,690  | 1.19 |

To determine an equation for the effect area of a continuous release of steam, four release cases (0.25 in., 1 in., 4 in., and 16 in.) were run for the varying steam pressures. A plot of the release rate vs. the area covered by a 20% concentration of steam shows a linear relationship, with an equation of:

$$A = 0.6 x$$

where

$A$  = the effect area in square feet,

$x$  = the release rate in lbs/sec.

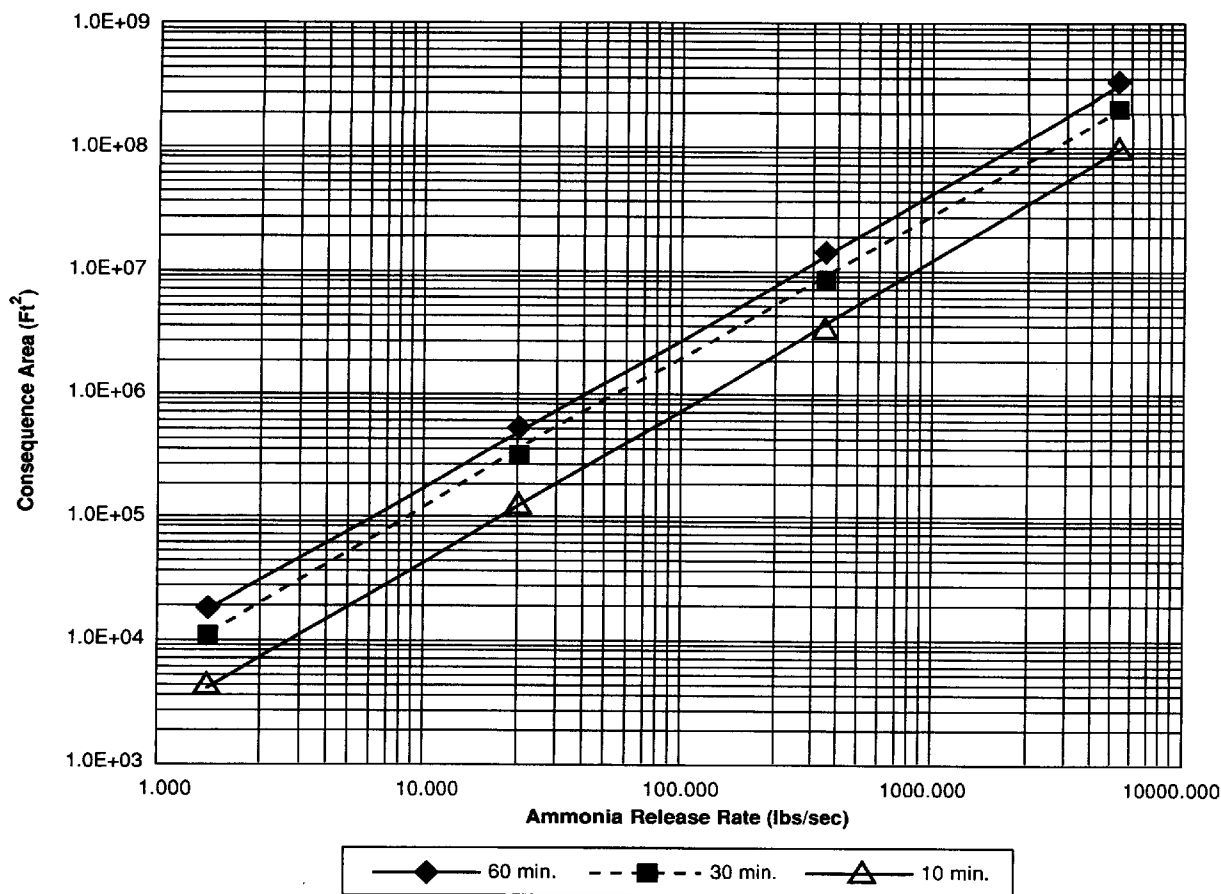


Figure 7-10—Continuous Ammonia Release

For instantaneous release cases, four masses of steam were modeled (10 lb, 100 lb, 1,000 lb, and 10,000 lb), and the relationship between inventory mass and area to 20% concentration was found to be:

$$A = 63.317 x^{0.6384}$$

where

$A$  = the effect area in square feet,

$x$  = the release mass in lbs.

### 7.9.7 Consequences of Acid/Caustic Leaks

For caustics/acids that have only splash type consequences, water was chosen as a representative fluid to determine the personnel effect area. This area was defined at the 180° semi-circular area covered by the liquid spray, or rainout. Modeling was performed at four pressures (15 psig, 30 psig, and 60 psig) for four hold sizes (0.25 in, 1 in, 4 in, and 16 in.). Only continuous releases were modeled, as instantaneous releases do not produce rainout. The results were analyzed to obtain a correlation between release rate and effect area. The resultant equations were obtained from Figure 7-4. The resulting equations are shown in Table 7-18.

Table 7-18—API-RBI Caustic/Acid Equations

| Pressure Range               | Equation                 |
|------------------------------|--------------------------|
| Low pressure—0-20 psig       | $y = 2,699.5 x^{0.2024}$ |
| Medium Pressure—21-40 psig   | $y = 3,366.2 x^{0.2878}$ |
| High Pressure $\geq 40$ psig | $y = 6,690 x^{0.2469}$   |

As seen in Figure 7-13, each pressure can be described by a unique relationship,

$$y = bx^c$$

where

$y$  = personnel effect area (ft²),

$x$  = release rate (lb/s), and  $b$  and  $c$  are constants for that pressure

The 45 psig and 60 psig trendlines are very close relative to the others. Therefore, these pressures were combined into one larger range ( $>40$  psig). The equation for the 60 psig trendline

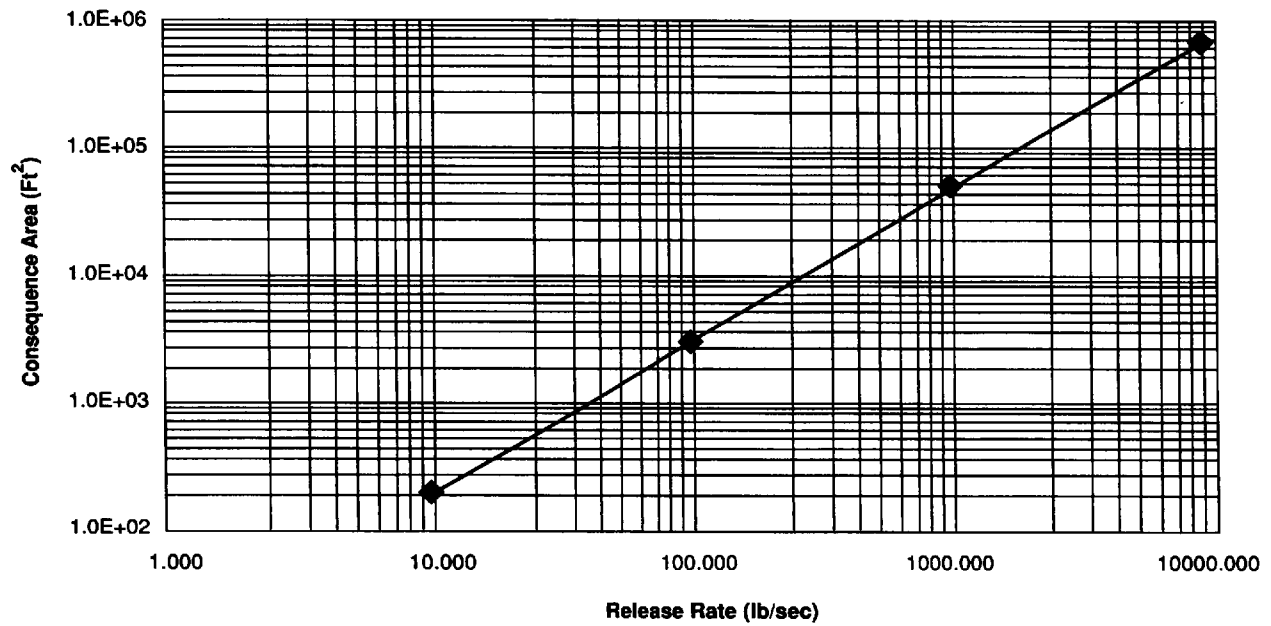


Figure 7-11—Instantaneous Chlorine Releases

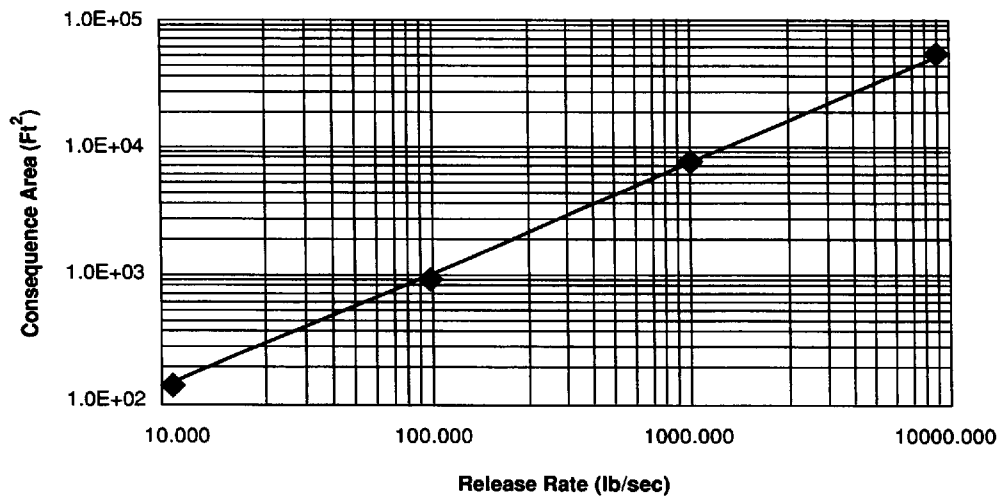


Figure 7-12—Instantaneous Ammonia Releases

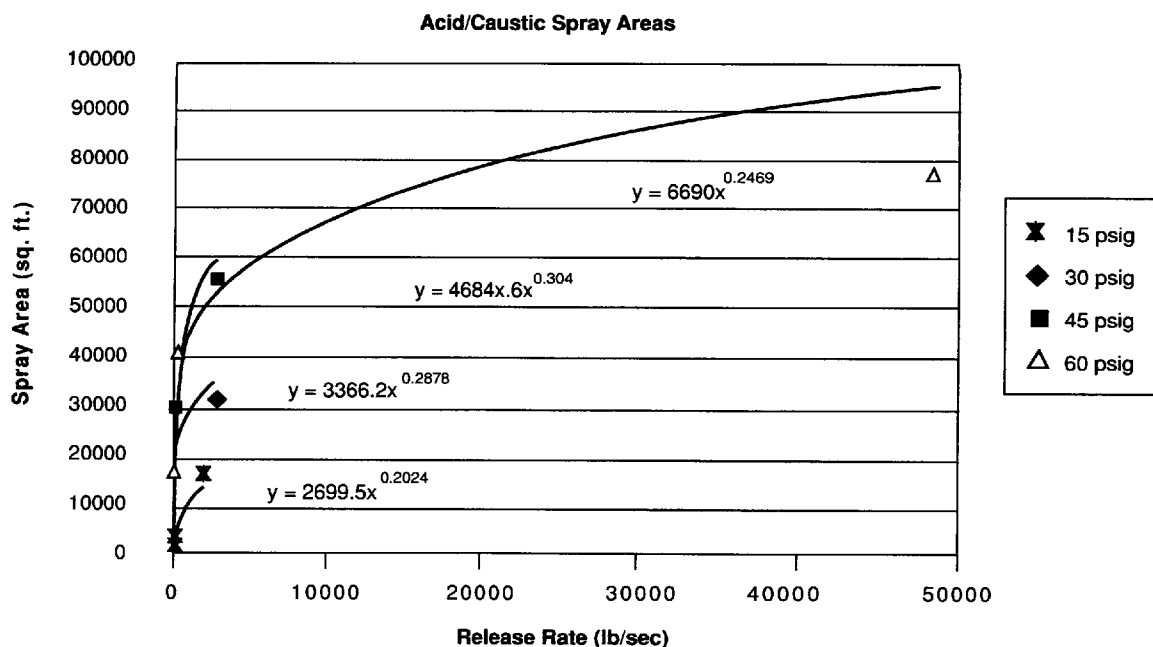


Figure 7-13—Caustic/Acid Modeling Results

was chosen to represent this range since it represents all possible release rates. Ranges were also chosen for the 15 and 30 psig cases.

The selected ranges represent the pressures at which caustics/acids are commonly used:

- Low pressure (15 psi)—representative of 0 – 20 psi.
- Medium pressure (30 psi)—representative of 21 – 40 psi.
- High pressure (60 psi)—representative of > 40 psi.

### 7.9.8 Effects of Mitigation Measures

To this point, isolation and detection capabilities have been taken into account in calculating the quantity of material that may be released during a loss-of-containment event. However, there may be additional systems, such as water spray, in place that can mitigate a release once the material has reached the atmosphere.

The effectiveness of mitigating systems can be simply accounted for in RBI by reducing the release rate and duration for continuous releases, or by reducing the release mass for instantaneous releases.

The RBI analyst will need to provide his or her own reduction factors, based on the effectiveness of their particular spray-system design or passive mitigation technology.

### 7.9.9 Environmental Cleanup Costs

Environmental consequences are expressed as a cost, so the consequences should be calculated separately and added to the

other costs in the “Business Interruption” section and included as part of the financial risk. The BRD methods allow for rigorous calculations, but also allow for simplifications and other assumptions based on the analyst’s opinions. Tables 7-19 through 7-23 are an attempt at simplifying the method as much as possible.

#### 7.9.9.1 Environmental Cleanup Costs Methods for Equipment Other Than Tank Bottoms

The user has the option whether or not to include environmental cost consequence in the risk equation. The default should be “No” (do not calculate). Most process equipment is located in specially paved and drained areas so that any liquid not evaporated or burned goes to special spill and waste handling facilities designed for the purpose of avoiding environmental consequences. An option is to allow the entry of the percent of fluid expected to escape from diked areas.

If the user wants to consider the environmental effects, he chooses whether the spill will be on the ground, or if it will go into water. This is very important for plants with storage and handling facilities on waterways.

First determine if the final state is a gas. If so, exit the module. Then determine if autoignition is likely. If so, also exit the module (the liquid will probably ignite and burn).

Only “liquid final state, autoignition not likely,” will be calculated. If the normal boiling point is less than 200°F, then exit the module. (See Section 7.2, presumably lighter boiling liquids will evaporate.)

Table 7-19—Environmental Cleanup Costs Inputs

| Input Variable:                            | Source:                           | Units                  |
|--------------------------------------------|-----------------------------------|------------------------|
| Consider environmental release?            | User input                        | Y/N                    |
| Release to ground or water?                | User input                        | Ground/ Water          |
| Damage factor from each damage module      | Damage module routine             | none                   |
| Representative fluid                       | User input                        | none                   |
| Final state liquid or gas                  | Consequence module                | none                   |
| Instantaneous or continuous release        | Consequence module                | none                   |
| Consequence module                         | Autoignition likely or not likely | none                   |
| Fluid density, converted to lb/gal         | Lookup table                      | lb/gal                 |
| Normal boiling point                       | Lookup tables                     | Deg. F                 |
| Release duration                           | Calculated from BRD Table 7-7     | minutes                |
| Release rate, for each hole size           | Consequence module                | lbs/sec                |
| Group inventory                            | Consequence module                | lbs                    |
| Percent of fluid evaporating               | From lookup table (see below)     | %                      |
| Equipment type                             | User input                        | none                   |
| Tank foundation type                       | User input from table (see below) | none                   |
| Detection time for floor leaks             | Lookup table                      | none                   |
| Generic failure frequency                  | Lookup table                      | events/yr              |
| New equipment type, tank floor             | Add to equipment table            |                        |
| Method of detection                        | User input                        |                        |
| Time of testing for tightness tests        | User input                        |                        |
| Percent of rupture contained by diked area | User input                        | %, (Default value 50%) |
| Cleanup cost, below ground                 | Lookup table (user changeable)    | \$/gallon              |
| Cleanup cost, above ground                 | Lookup table (user changeable)    | \$/gallon              |
| Cleanup cost, water                        | Lookup table (user changeable)    | \$/gallon              |

Check to see if the release is instantaneous or continuous. Instantaneous releases use the entire group inventory. For continuous releases, calculate the release duration from Table 7-7. Check that the release duration is not limited by the flow rate for each hole size. Use the minimum value for duration. Use the duration, flow rate, and density to calculate the gallons of liquid released. Physical properties of representative fluids in the BRD are shown in Table 7-2. Subtract from this value the percent of liquid expected to evaporate (e.g. in a 24-hour period) as shown in Table 7-20.

Multiply the remaining fluid by the cost of fluid cleanup, based on ground or water release. Multiply this value by the hole-size frequency times the combined technical module subfactors. Add all resulting values to get the environmental cost risk in \$/yr. Multiply this times 0.9 to account for releases that ignite and do not result in environmental contamination.

#### 7.9.9.2 Environmental Cleanup Costs Methods for Tank Bottoms

If the equipment type is a tank bottom, only small ( $1/4$ -in.) and medium (1-in.) hole sizes are considered. For lack of better data, the generic failure frequency for tanks can be used (these surely include some bottom leaks).

The user specifies the type of foundation and the type of leak detection (see Tables 7-22 and 7-23). Note that for tightness testing (not usually done; involves cleaning, filling with water and holding for a period of time), the time between tests (e.g. one year) must be specified.

Use either the flow rate based on foundation and test time or the threshold value for the leak detection method to determine the leak amount as shown in Table 7-23. Multiply the leak amount times the cost of underground leak cleanup. Multiply times the generic frequency and the combined technical module subfactors. This will produce the risk of underground leaks.



Table 7-20—Fluid Leak Properties

| Fluid                            | Molecular Weight | Density | NBP  | % Evaporating in 24 hours* |
|----------------------------------|------------------|---------|------|----------------------------|
| H <sub>2</sub>                   | 2                | 4.433   | -423 | 100                        |
| C <sub>1</sub> -C <sub>2</sub>   | 23               | 15.639  | -193 | 100                        |
| H <sub>2</sub> S                 | 34               | 61.993  | -75  | 100                        |
| C <sub>3</sub> -C <sub>5</sub>   | 58               | 36.209  | 31   | 100                        |
| HF                               | 20               | 60.37   | 68   | 100                        |
| C <sub>6</sub> -C <sub>8</sub>   | 100              | 42.702  | 210  | 90                         |
| C <sub>9</sub> -C <sub>12</sub>  | 149              | 45.823  | 364  | 50                         |
| C <sub>13</sub> -C <sub>16</sub> | 205              | 47.728  | 502  | 10                         |
| C <sub>17</sub> -C <sub>25</sub> | 280              | 48.383  | 651  | 5                          |
| C <sub>25</sub> +                | 422              | 56.187  | 981  | 2                          |

\* Estimated Values

Table 7-21—Environmental Cleanup Costs Outputs

| Output Name                                        | Primary/Secondary | Units   |
|----------------------------------------------------|-------------------|---------|
| Volume released, for each hole size                | Secondary         | gallons |
| Volume released to environment, for each hole size | Secondary         | gallons |
| Cleanup cost, for each hole size                   | Secondary         | \$      |
| Total cleanup cost                                 | Secondary         | \$      |
| Cleanup risk for each hole size                    | Secondary         | \$/yr   |
| Total cleanup risk                                 | Primary           | \$/yr   |

Table 7-22—Tank Underground Leak Rates for RBI Analysis

| Type of Foundation | Leak Rate (gal/day) |             |
|--------------------|---------------------|-------------|
|                    | 1/4 inch hole       | 1 inch hole |
| Clay               | 0.038               | 0.15        |
| Silt               | 5.25                | 24          |
| Sand               | 6.5                 | 29          |
| Gravel             | 42                  | 192         |

Table 7-23—Detection Times for Storage Tank Floor Leaks

| Method of Detection  | Time to Detect (days) or Threshold (gallons) |
|----------------------|----------------------------------------------|
| Tightness Testing    | Time—interval between tests                  |
| Inventory Monitoring | Threshold—10% tank volume                    |
| U-Tubes              | Threshold—500 gal                            |
| Vapor Wells          | Time—1 month                                 |

## 7.10 FINANCIAL RISK EVALUATION

In the April 1995 Base Resource Document, risk could be calculated using cost as the measure of consequence. This was referred to as the "business interruption" approach. Use of this method revealed a few potentially serious shortcomings:

- a. The method used only the affected area as the basis of determining the cost of a failure. This led to zero cost for equipment that had zero affected area (e.g. nonflammable, nontoxic releases).
- b. The method considered only business interruption as the basis of the cost associated with a failure.

These problems are addressed in the "Level III" approach by recognizing that there are many costs associated with any failure of equipment in a process plant. These include, but are not limited to:

- a. Cost of equipment repair and replacement
- b. Downtime associated with equipment repair and replacement
- c. Costs due to potential injuries associated with a failure
- d. Environmental cleanup costs

The modified approach for Level III is to consider all of these costs on **both** an equipment specific basis and an affected area basis. Thus, any failure has costs associated with it, whether or not the failure actually results in the release of a hazardous fluid. Recognizing and using this fact presents a more realistic value of the risk associated with a failure. Since the costs include more than just business interruption, the approach used for Level III is called the "financial risk" approach.

### 7.10.1 Conclusions: Risk Comparison of Affected Area Basis vs. Financial Basis

Table 7-24 shows methods similar to the Level III methods above worked into an example from a typical distillation unit. Note carefully the risk ranking based on affected area vs. the risk ranking based on financial risk. There is very little difference in the high risk items with one very important exception. Item P-31 is a pipe containing a non-flammable and non-toxic fluid. Based on affected area, the consequence is zero, therefore the risk is zero. Using only the consequence area as the basis for risk, the item was ranked near the very bottom of equipment. When the cost of the item failure was included, this item automatically jumped to near the top of the list. This is primarily due to a very high technical module subfactor. The pipe is subject to a damage mechanism and based on technical module inputs of damage rate and past inspections, the pipe has a high likelihood of failure. By allowing the costs of failure to be considered, the financial risk pointed out that a potential for failure with repair, replacement, and downtime was to be considered.

## 7.10.2 Financial Risk Methods

The basic method of risk analysis is presented in the BRD is not changed for the financial risk analysis. The risk is still calculated as the consequence of failure (now expressed as cost in dollars) times the likelihood of failure. For a rigorous and flexible analysis, the consequences (costs) are evaluated at the hole size level. Risk is also evaluated at the hole size level by using the likelihood of failure associated with each hole size. The total risk is calculated as the sum of the risks of each hole size.

### 7.10.2.1 Equipment Damage Costs—By Specific Items

The most serious problem with the original (April 1995) BRD "business interruption" approach is that the cost of the equipment item being evaluated was not directly considered. Thus any failure with zero affected area led to zero risk. This is not realistic, since a failure of a steam pipe definitely has a cost impact, even if it does not result in a large area of damage compared to a hydrocarbon pipe.

The solution is to evaluate the cost of the equipment failure itself, independent of whether or not it has an affected area. Then, any other costs can be added. Testing of this method has resulted in nonflammable piping moving from near the bottom of the risk ranking to near the top, especially if it has a high likelihood of failure due to some damage mechanism. Thus, such a pipe would be appropriately considered by Risk-Based Inspection as a high priority candidate for inspection.

The method was tested using both a composite financial on the combination of all possible leak scenarios (hole sizes), and using a specific cost associated with each hole size and unique to each equipment item. The latter approach was chosen based on the inherent differences in the costs associated with very small compared to very large holes. A small hole in a piping system can sometimes be repaired with little or no impact on production by use of a temporary clamp until a permanent repair can be scheduled during normal maintenance shutdowns. Larger holes usually do not allow this option, and shutdown plus repair costs are greatly increased.

Table 7-25 shows the equipment damage costs suggested for the equipment included in the BRD. Actual failure cost data for equipment should be used if available.

Note that piping cost estimates are on a per foot basis. The sources cited were used to estimate the relative installed costs of the equipment. Since repair or replacement of equipment usually does not involve replacement of all supports, foundations, etc., the repair and replacement costs presented do not reflect actual installed cost.

The cost estimates shown in Table 7-25 are based on carbon steel prices. It is suggested for the Level III approach that these costs be multiplied by a material cost factor for other materials. Table 7-26 shows the suggested values for these cost factors. These factors are based on a variety of sources from manufacturer's data and cost quotations.

Table 7-24—Risk Comparison of a Typical Distillation Unit

| ID    | Equipment Type | Representative Fluid             | Fluid State | Risk ft <sup>2</sup> /yr | Risk Rank ft <sup>2</sup> /yr | Risk \$/yr   | Risk Rank \$/yr | Consequence Area (ft <sup>2</sup> ) | Sum Tech. Mod. Subfactors | Damage Adjusted Frequency |
|-------|----------------|----------------------------------|-------------|--------------------------|-------------------------------|--------------|-----------------|-------------------------------------|---------------------------|---------------------------|
| P-30  | Pipe-6         | C <sub>3</sub> -C <sub>5</sub>   | Liquid      | 1092                     | 1                             | \$ 5,573,859 | 1               | 1296                                | 3205.1                    | 8.42E-01                  |
| P-41  | Pipe->16       | C <sub>17</sub> -C <sub>25</sub> | Liquid      | 193                      | 2                             | \$ 936,178   | 2               | 6487                                | 170.6                     | 2.97E-02                  |
| P-42  | Pipe-10        | C <sub>17</sub> -C <sub>25</sub> | Liquid      | 154                      | 3                             | \$ 754,536   | 3               | 5562                                | 185.0                     | 2.78E-02                  |
| C-1   | Column top     | C <sub>6</sub> -C <sub>8</sub>   | Vapor       | 133                      | 4                             | \$ 651,147   | 4               | 1322                                | 646.9                     | 1.01E-01                  |
| E-33  | Exchanger-TS   | C <sub>6</sub> -C <sub>8</sub>   | Liquid      | 31                       | 5                             | \$ 166,135   | 5               | 1692                                | 115.7                     | 1.80E-02                  |
| E-37  | Exchanger-TS   | C <sub>6</sub> -C <sub>8</sub>   | Liquid      | 31                       | 6                             | \$ 166,135   | 6               | 1692                                | 115.7                     | 1.80E-02                  |
| E-39  | Exchanger-TS   | C <sub>6</sub> -C <sub>8</sub>   | Liquid      | 31                       | 7                             | \$ 166,135   | 7               | 16.92                               | 115.7                     | 1.80E-02                  |
| E-52  | Exchanger      | C <sub>25</sub> +                | Liquid      | 22                       | 9                             | \$ 161,306   | 8               | 203                                 | 683.3                     | 1.07E-01                  |
| P-3   | Pipe-12        | C <sub>25</sub> +                | Liquid      | 16                       | 11                            | \$ 126,325   | 10              | 190                                 | 641.6                     | 8.66E-02                  |
| P-40  | Pipe-8         | C <sub>9</sub> -C <sub>12</sub>  | Liquid      | 19                       | 10                            | \$ 100,906   | 11              | 1713                                | 80.7                      | 1.13E-02                  |
| P-1   | Pipe-12        | C <sub>25</sub> +                | Liquid      | 8                        | 14                            | \$ 75,669    | 12              | 93                                  | 653.6                     | 8.82E-02                  |
| D-4   | Drum           | C <sub>6</sub> -C <sub>8</sub>   | Liquid      | 12                       | 12                            | \$ 69,461    | 13              | 711                                 | 110.2                     | 1.72E-02                  |
| D-10  | Drum           | C <sub>3</sub> -C <sub>5</sub>   | Liquid      | 9                        | 13                            | \$ 44,980    | 14              | 1493                                | 37.7                      | 5.88E-03                  |
| P-11  | Pipe-12        | C <sub>13</sub> -C <sub>16</sub> | Liquid      | 8                        | 15                            | \$ 41,432    | 15              | 1086                                | 51.5                      | 6.95E-03                  |
| P-31  | Pipe-1         | Misc.                            | Liquid      | 0                        | 200                           | \$ 40,907    | 16              | 0                                   | 3846.2                    | 9.72E-01                  |
| P-23  | Pipe->16       | C <sub>9</sub> -C <sub>12</sub>  | Liquid      | 6                        | 16                            | \$ 34,437    | 17              | 1539                                | 23.9                      | 4.16E-03                  |
| E-100 | Exchanger      | C <sub>25</sub> +                | Liquid      | 5                        | 17                            | \$ 24,630    | 18              | 6194                                | 5.2                       | 8.16E-04                  |
| E-54  | Exchanger      | C <sub>25</sub> +                | Liquid      | 3                        | 21                            | \$ 24,254    | 19              | 203                                 | 102.7                     | 1.60E-02                  |
| P-8   | Pipe-8         | C <sub>13</sub> -C <sub>16</sub> | Liquid      | 4                        | 18                            | \$ 22,944    | 20              | 1610                                | 18.9                      | 2.73E-03                  |
| E-42  | Exchanger      | C <sub>25</sub> +                | Liquid      | 3                        | 22                            | \$ 22,895    | 21              | 198                                 | 98.6                      | 1.54E-02                  |

### 7.10.2.2 Equipment Damage Costs—Other Affected Equipment

As presented in the BRD, it is still necessary to calculate the equipment damage costs to other equipment in the vicinity of the failure, if the failure results in a flammable event. It is intended that for the Level III approach a Process Unit constant value of equipment cost per ft<sup>2</sup> be used as a default value for all equipment in the unit. In other words, as a starting point the average cost of other equipment surrounding any given piece of equipment is about the same. This could be refined for individual equipment items by allowing the default value to be overridden with a higher or lower value where appropriate. For illustration purposes, an average cost of equipment used in the pilot study was \$550/ft<sup>2</sup>. This value is multiplied by the affected area to obtain the cost of other equipment damaged by the failure.

### 7.10.2.3 Business Interruption Costs—By Specific Items

Another weakness in the original (April 1995) BRD "Business Interruption" approach was that the downtime associated with an individual equipment failure was also based on affected area. Thus the downtime of the failure itself was not considered, and if the failure had zero affected area, again the cost associated with it was zero.

This weakness is corrected in much the same way that the weakness of not considering equipment damage and repair was corrected. For each hole size, an estimated down time for each equipment item is presented in Table 7-27.

Centrifugal pumps are assumed to have on-line spares, so there is no downtime associated with the failure of these equipment types.

Table 7-25—Equipment Damage Costs

| Type      | Description                    | Failure Cost Small* | Failure Cost Medium* | Failure Cost Large* | Failure Cost Rupture* |
|-----------|--------------------------------|---------------------|----------------------|---------------------|-----------------------|
| Pump1     | Centrifugal Pump, single seal  | \$1,000             | \$2,500              | \$5,000             | \$5,000               |
| Pump2     | Centrifugal Pump, double seal  | \$1,000             | \$2,500              | \$5,000             | \$5,000               |
| ColumnBTM | Column                         | \$10,000            | \$25,000             | \$50,000            | \$100,000             |
| ColumnTop | Column                         | \$10,000            | \$25,000             | \$50,000            | \$100,000             |
| CompC     | Compressor, Centrifugal        | \$10,000            | \$20,000             | \$100,000           | \$300,000             |
| CompR     | Compressor, Reciprocating      | \$5,000             | \$10,000             | \$50,000            | \$100,000             |
| Filter    | Filter                         | \$1,000             | \$2,000              | \$4,000             | \$10,000              |
| Finfan    | Fin/Fan Coolers                | \$1,000             | \$2,000              | \$20,000            | \$40,000              |
| Exchanger | Heat Exchanger, Shell          | \$1,000             | \$2,000              | \$20,000            | \$60,000              |
| Pipe-0.75 | Piping, 0.75" diameter, per ft | \$5                 | \$0                  | \$0                 | \$10                  |
| Pipe-1    | Piping, 1" diameter, per ft    | \$5                 | \$0                  | \$0                 | \$20                  |
| Pipe-2    | Piping, 2" diameter, per ft    | \$5                 | \$0                  | \$0                 | \$40                  |
| Pipe-4    | Piping, 4" diameter, per ft    | \$5                 | \$10                 | \$0                 | \$60                  |
| Pipe-6    | Piping, 6" diameter, per ft    | \$5                 | \$20                 | \$0                 | \$120                 |
| Pipe-8    | Piping, 8" diameter, per ft    | \$5                 | \$30                 | \$60                | \$180                 |
| Pipe-10   | Piping, 10" diameter, per ft   | \$5                 | \$40                 | \$80                | \$240                 |
| Pipe-12   | Piping, 12" diameter, per ft   | \$5                 | \$60                 | \$120               | \$360                 |
| Pipe-16   | Piping, 16" diameter, per ft   | \$5                 | \$80                 | \$160               | \$500                 |
| Pipe->16  | Piping, >16" diameter, per ft  | \$10                | \$120                | \$240               | \$700                 |
| Drum      | Pressure vessels               | \$5,000             | \$12,000             | \$20,000            | \$40,000              |
| Reactor   | Reactor                        | \$10,000            | \$24,000             | \$40,000            | \$80,000              |
| PumpR     | Reciprocating Pumps            | \$1,000             | \$2,500              | \$5,000             | \$10,000              |
| Tank      | Atmospheric Storage Tank       | \$40,000            | \$40,000             | \$40,000            | \$80,000              |
| Heater    | Furnace Tubes for Fired Heater | \$1,000             | \$10,000             | \$30,000            | \$60,000              |

## \* Sources:

1. Yamartino, J., "Installed Cost of Corrosion Resistant Piping—1978", Chemical Engineering, Nov. 30, 1978.
2. Peters, M. S., Timmerhaus, K.D., Plant Design and Economics for Chemical Engineers, McGraw-Hill, 1968.

Table 7-26—Material Cost Factors

| Material         | Cost Factor | Material          | Cost Factor |
|------------------|-------------|-------------------|-------------|
| Carbon Steel     | 1.0         | Clad Alloy 600    | 7.0         |
| 1 1/4 Cr 1/2 Mo  | 1.3         | CS "Teflon" Lined | 7.8         |
| 2 1/4 Cr 1/2 Mo  | 1.7         | Clad Nickel       | 8.0         |
| 5 Cr 1/2 Mo      | 1.7         | Alloy 800         | 8.4         |
| 7 Cr 1/2 Mo      | 2.0         | 70/30 Cu/Ni       | 8.5         |
| Clad 304 SS      | 2.1         | 904L              | 8.8         |
| 9 Cr 1/2 Mo      | 2.6         | Alloy 20          | 11          |
| 405 SS           | 2.8         | Alloy 400         | 15          |
| 410 SS           | 2.8         | Alloy 600         | 15          |
| 304SS            | 3.2         | Nickel            | 18          |
| Clad 316 SS      | 3.3         | Alloy 625         | 26          |
| CS "Saran" lined | 3.4         | Titanium          | 28          |
| CS Rubber Lined  | 4.4         | Alloy "C"         | 29          |
| 316 SS           | 4.8         | Zirconium         | 34          |
| CS Glass Lined   | 5.8         | Alloy "B"         | 36          |
| Clad Alloy 400   | 6.4         | Tantalum          | 535         |
| 90/10 Cu/Ni      | 6.8         |                   |             |

Table 7-27—Estimated Equipment Down Time

| Type      | Description                    | Outage Time<br>Small | Outage Time<br>Medium | Outage Time<br>Large | Outage Time<br>Rupture |
|-----------|--------------------------------|----------------------|-----------------------|----------------------|------------------------|
| Pump1     | Centrifugal Pump, single seal  | 0                    | 0                     | 0                    | 0                      |
| Pump2     | Centrifugal Pump, double seal  | 0                    | 0                     | 0                    | 0                      |
| ColumnBTM | Column                         | 2                    | 4                     | 5                    | 21                     |
| Columntop | Column                         | 2                    | 4                     | 5                    | 21                     |
| CompC     | Compressor, Centrifugal        | 2                    | 3                     | 7                    | 14                     |
| CompR     | Compressor, Reciprocating      | 2                    | 3                     | 7                    | 14                     |
| Filter    | Filter                         | 0                    | 1                     | 1                    | 1                      |
| Finfan    | Fin/Fan Coolers                | 1                    | 1                     | 3                    | 5                      |
| Exchanger | Heat Exchanger, Shell          | 1                    | 1                     | 3                    | 5                      |
| Pipe-0.75 | Piping, 0.75" diameter, per ft | 0                    | 0                     | 0                    | 1                      |
| Pipe-1    | Piping, 1" diameter, per ft.   | 0                    | 0                     | 0                    | 1                      |
| Pipe-2    | Piping, 2" diameter, per ft    | 0                    | 0                     | 0                    | 2                      |
| Pipe-4    | Piping, 4" diameter, per ft    | 0                    | 1                     | 0                    | 2                      |
| Pipe-6    | Piping, 6" diameter, per ft    | 0                    | 1                     | 2                    | 3                      |
| Pipe-8    | Piping, 8" diameter, per ft    | 0                    | 2                     | 3                    | 3                      |
| Pipe-10   | Piping, 10" diameter, per ft   | 0                    | 2                     | 3                    | 4                      |
| Pipe-12   | Piping, 12" diameter, per ft   | 0                    | 3                     | 4                    | 4                      |
| Pipe-16   | Piping, 16" diameter, per ft   | 0                    | 3                     | 4                    | 5                      |
| Pipe->16  | Piping, >16" diameter, per ft  | 1                    | 4                     | 5                    | 7                      |
| Drum      | Pressure vessels               | 2                    | 3                     | 3                    | 7                      |
| Reactor   | Reactor                        | 4                    | 6                     | 6                    | 14                     |
| Pumpr     | Reciprocating Pumps            | 0                    | 0                     | 0                    | 0                      |
| Tank      | Atmospheric Storage Tank       | 0                    | 0                     | 0                    | 7                      |
| Heater    | Furnace Tubes for Fired Heater | 1                    | 2                     | 4                    | 5                      |

#### 7.10.2.4 Business Interruption Costs—Other Affected Equipment

If a failure does have an affected area, the cost of downtime for replacement and repair of other affected equipment must be considered. The Level III approach still uses the downtime associated with a total cost of other equipment damage. Figure 7-14 shows the method:

#### 7.10.2.5 Potential Injury Costs

Another cost to consider when a failure occurs is the potential injury costs. This a controversial area, but need not be. When a business takes this cost into account in a risk management scheme, then appropriate resources can be spent to prevent these injuries from happening. Just as failure to consider the business cost of a zero affected area

event can lead to under ranking this event with respect to risk, if injury costs are not considered, then a risk could be present that is not considered in allocating inspection resources.

The method for the Level III approach is to use a process unit constant of population density as a default for all equipment in the unit. This default value can be overridden by higher or lower values depending on specific equipment location with respect to controls rooms, walkways, roads, etc. In addition to the population density, the cost per individual affected must also be entered. This value must be sufficiently high to adequately represent typical costs to businesses of an injury up to and including fatal injuries. For the example that follows, the population density was set at 0.0001 persons per ft<sup>2</sup> (one person per 10,000 ft<sup>2</sup>), and the cost per injury was set at \$10,000,000.

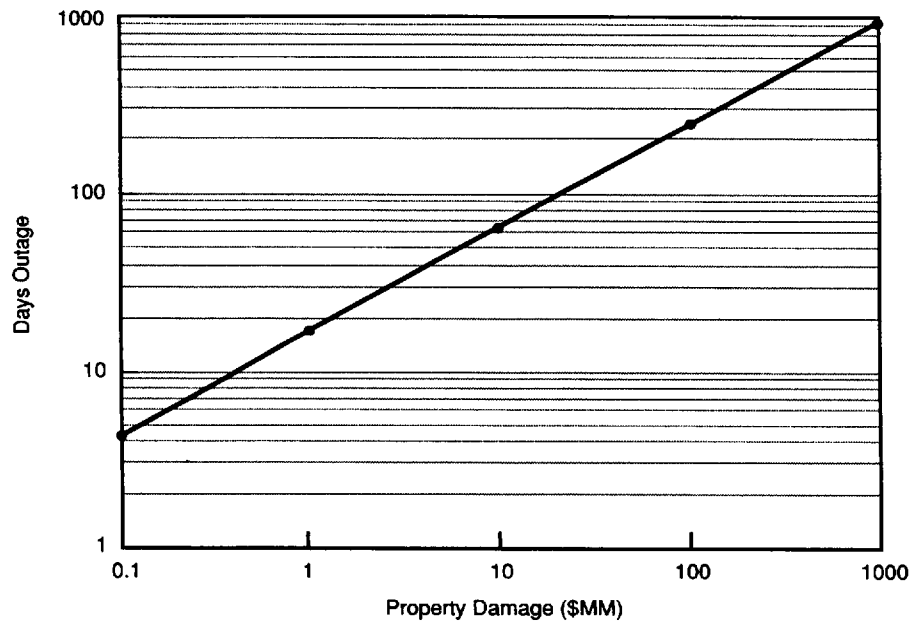


Figure 7-14—Business Interruption Costs

## Section 8—Likelihood Analysis

### 8.1 OVERVIEW OF PROCESS FOR LIKELIHOOD ANALYSIS

As with other Risk-Based Inspection methods in the Base Resource Document, the following represents a suggested methodology. More detailed analysis may yield more accurate results. The likelihood analysis begins with a database of generic failure frequencies for onshore refining and chemical processing equipment. These generic frequencies are then modified by two terms, the equipment modification factor (FE) and the management systems evaluation factor (FM), to yield an adjusted failure frequency, as follows:

$$Frequency_{adjusted} = Frequency_{generic} \times F_E \times F_M \quad (8.1)$$

This calculation is shown graphically in Figure 8-1.

The modification factors reflect identifiable differences between process units and among equipment items within a process unit. The first adjustment, the equipment modification factor, examines details specific to each equipment item and to the environment in which that item operates, in order to develop a modification factor unique to that piece of equipment. The second correction, the management systems evaluation factor, adjusts for the influence of the facility's management system on the mechanical integrity of the plant. This adjustment is applied equally to all equipment items. If the management systems being evaluated are different for different units or areas of the plant, the differences should be identified and the management systems evaluation factor adjusted accordingly.

Modification factors with a value greater than 1.0 will increase the adjusted failure frequency, and those with a value less than 1.0 will decrease it. Both modification factors are always positive numbers.

#### 8.1.1 Generic Failure Frequency

The database of generic failure frequencies is based on a compilation of available records of equipment failure histories. The records can come from a variety of sources. Generic failure frequencies have been developed from these data for each type of equipment and each diameter of piping. A detailed generic database is presented in Section 8.2 and Table 8-1.

#### 8.1.2 Equipment Modification Factor

The equipment modification factor identifies the specific conditions that can have a major influence on the failure frequency of the equipment item. These conditions are categorized into four subfactors:

- The technical module that examines materials of construction, the environment and the inspection program.
- Universal conditions that affect all equipment items at the facility.
- Mechanical considerations that vary from item to item.
- Process influences that can affect equipment integrity

The equipment modification factor is discussed in 8.3.

#### 8.1.3 Management Systems Evaluation Factor

The effectiveness of a company's process safety management system can have a pronounced effect on mechanical integrity. The RBI procedure includes an evaluating tool to assess the portions of the facility's management systems that most directly impact failure frequency of equipment items. This evaluation consists of a series of interviews with inspection, maintenance, process, and safety personnel. The questions are based primarily on guidelines from API (RP 750, Std. 510, Std. 570, etc.).

The evaluation is sufficiently detailed to provide effective discrimination between management systems. It is described in 8.4, and the evaluation workbook is included as Appendix C. A scale is provided in Figure 8-5 to convert the evaluation score to a management systems evaluation factor.

### 8.2 GENERIC FAILURE FREQUENCIES

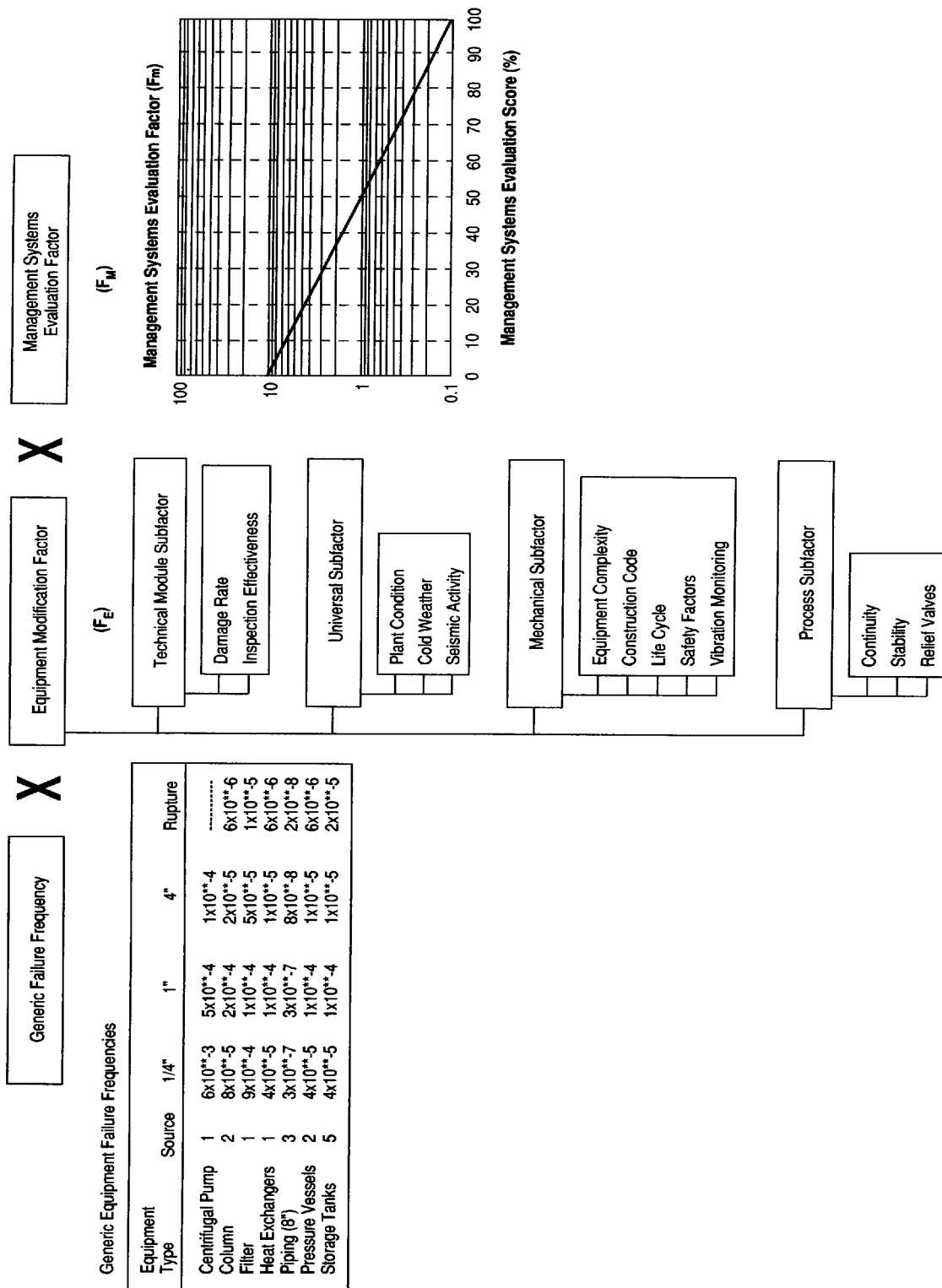
If enough data were available for a given equipment item, true failure probabilities could be calculated from actual observed failures. Even if no failures have occurred in a piece of equipment, we know from experience that the true failure probability is greater than zero, and that the equipment item has not operated long enough to experience a failure.

As a first step in estimating this non-zero probability, it is necessary to turn to a larger equipment pool to find enough failures to provide a reasonable estimate of the true probability. This generic equipment pool is used to produce a generic failure frequency.

The generic failure frequencies are built using records from all plants within a company or from various plants within an industry, from literature sources, past reports, and commercial data bases. Therefore, the generic values represent an industry in general and do not reflect the true failure frequencies for a specific plant or unit.

Generic frequencies are assumed to follow a log-normal distribution, with error rates ranging from 3 to 10. Median values are quoted in Table 8-1.

The RBI method requires that the analyst use a generic failure frequency to "jump start" the probability analysis. A data source should be chosen that represents plants or equipment similar to the equipment being modeled. For instance, much high-quality generic data can be derived from nuclear



### Figure 8-1—Calculating Adjusted Failure Frequencies



Table 8-1—Suggested Generic Equipment Failure Frequencies

| Equipment Type                    | Data Source (References) | Leak Frequency (per year for four hole sizes) |                    |                    |                    |
|-----------------------------------|--------------------------|-----------------------------------------------|--------------------|--------------------|--------------------|
|                                   |                          | 1/4 in.                                       | 1 in.              | 4 in.              | Rupture            |
| Centrifugal Pump, single seal     | 1                        | $6 \times 10^{-2}$                            | $5 \times 10^{-4}$ | $1 \times 10^{-4}$ |                    |
| Centrifugal Pump, double seal     | 1                        | $6 \times 10^{-3}$                            | $5 \times 10^{-4}$ | $1 \times 10^{-4}$ |                    |
| Column                            | 2                        | $8 \times 10^{-5}$                            | $2 \times 10^{-4}$ | $2 \times 10^{-5}$ | $6 \times 10^{-6}$ |
| Compressor, Centrifugal           | 1                        |                                               | $1 \times 10^{-3}$ | $1 \times 10^{-4}$ |                    |
| Compressor, Reciprocating         | 6                        |                                               | $6 \times 10^{-3}$ | $6 \times 10^{-4}$ |                    |
| Filter                            | 1                        | $9 \times 10^{-4}$                            | $1 \times 10^{-4}$ | $5 \times 10^{-5}$ | $1 \times 10^{-5}$ |
| Fin/Fan Coolers                   | 3                        | $2 \times 10^{-3}$                            | $3 \times 10^{-4}$ | $5 \times 10^{-8}$ | $2 \times 10^{-8}$ |
| Heat Exchanger, Shell             | 1                        | $4 \times 10^{-5}$                            | $1 \times 10^{-4}$ | $1 \times 10^{-5}$ | $6 \times 10^{-6}$ |
| Heat Exchanger, Tube Side         | 1                        | $4 \times 10^{-5}$                            | $1 \times 10^{-4}$ | $1 \times 10^{-5}$ | $6 \times 10^{-6}$ |
| Piping, 0.75 in. diameter, per ft | 3                        | $1 \times 10^{-5}$                            |                    |                    | $3 \times 10^{-7}$ |
| Piping, 1 in. diameter, per ft    | 3                        | $5 \times 10^{-6}$                            |                    |                    | $5 \times 10^{-7}$ |
| Piping, 2 in. diameter, per ft    | 3                        | $3 \times 10^{-6}$                            |                    |                    | $6 \times 10^{-7}$ |
| Piping, 4 in. diameter, per ft    | 3                        | $9 \times 10^{-7}$                            | $6 \times 10^{-7}$ |                    | $7 \times 10^{-8}$ |
| Piping, 6 in. diameter, per ft    | 3                        | $4 \times 10^{-7}$                            | $4 \times 10^{-7}$ |                    | $8 \times 10^{-8}$ |
| Piping, 8 in. diameter, per ft    | 3                        | $3 \times 10^{-7}$                            | $3 \times 10^{-7}$ | $8 \times 10^{-8}$ | $2 \times 10^{-8}$ |
| Piping, 10 in. diameter, per ft   | 3                        | $2 \times 10^{-7}$                            | $3 \times 10^{-7}$ | $8 \times 10^{-8}$ | $2 \times 10^{-8}$ |
| Piping, 12 in. diameter, per ft   | 3                        | $1 \times 10^{-7}$                            | $3 \times 10^{-7}$ | $3 \times 10^{-8}$ | $2 \times 10^{-8}$ |
| Piping, 16 in. diameter, per ft   | 3                        | $1 \times 10^{-7}$                            | $2 \times 10^{-7}$ | $2 \times 10^{-8}$ | $2 \times 10^{-8}$ |
| Piping, > 16 in. diameter, per ft | 3                        | $6 \times 10^{-8}$                            | $2 \times 10^{-7}$ | $2 \times 10^{-8}$ | $1 \times 10^{-8}$ |
| Pressure Vessels                  | 2                        | $4 \times 10^{-5}$                            | $1 \times 10^{-4}$ | $1 \times 10^{-5}$ | $6 \times 10^{-6}$ |
| Reactor                           | 2                        | $1 \times 10^{-4}$                            | $3 \times 10^{-4}$ | $3 \times 10^{-5}$ | $2 \times 10^{-5}$ |
| Reciprocating Pumps               | 7                        | 0.7                                           | .01                | .001               | .001               |
| Atmospheric Storage Tank          | 5                        | $4 \times 10^{-5}$                            | $1 \times 10^{-4}$ | $1 \times 10^{-5}$ | $2 \times 10^{-5}$ |

plant reporting databases; however, the data may not be appropriate to a refinery application because of the differences in maintenance and inspection quality, and in the nature of the service. The analyst should always be familiar with generic data sources being used, and their appropriateness to the equipment being analyzed.

A suggested list of generic failure frequencies and their sources are provided in Table 8-1.

### 8.3 EQUIPMENT MODIFICATION FACTOR

An equipment modification factor, or FE, is developed for each equipment item, based on the specific environment in which the item operates. The FE is composed of four subfactors which will be discussed below. An overview of the equipment modification factor is shown in Figure 8-2.

Each subfactor is composed of several elements which are analyzed according to well-defined rules. For each element, numeric values are assigned to indicate how much the failure frequency will deviate from generic, as a result of the condition being analyzed. Positive values are assigned for conditions that are judged to be more deleterious than generic, and negative values are used to indicate a reduction in expected failure frequency. A value of +10 is assigned when the condi-

tion is expected to increase failure frequency approximately one order of magnitude.

Throughout this portion of an RBI analysis, it is assumed that all equipment items have been designed and fabricated in accordance with industry and company standard design practices, unless there is specific evidence to the contrary. These standard practices are generally based on recognized industry standards, such as ASME, TEMA, and ANSI. It is beyond the scope of an RBI analysis to confirm design accuracy. RBI highlights the conditions that can have an adverse influence on properly designed equipment. The numeric values derived reflect the impact of these conditions on failure frequency.

All numeric values assigned to quantify the rate of damage are positive numbers, since probability of failure cannot be reduced by the existence of a damage mechanism. However, by definition, generic failure frequency data include all equipment items, some with on-going damage mechanisms and some without. It follows that when an equipment item has no operative damage mechanism, it should have a failure frequency that is somewhat lower than generic. To account for this, all equipment items are assigned a base numeric value of -2.0, and damage mechanism values are added as appropriate. The -2.0 base adjustment value was developed while validating a plant-wide RBI study. When no damage mechanisms

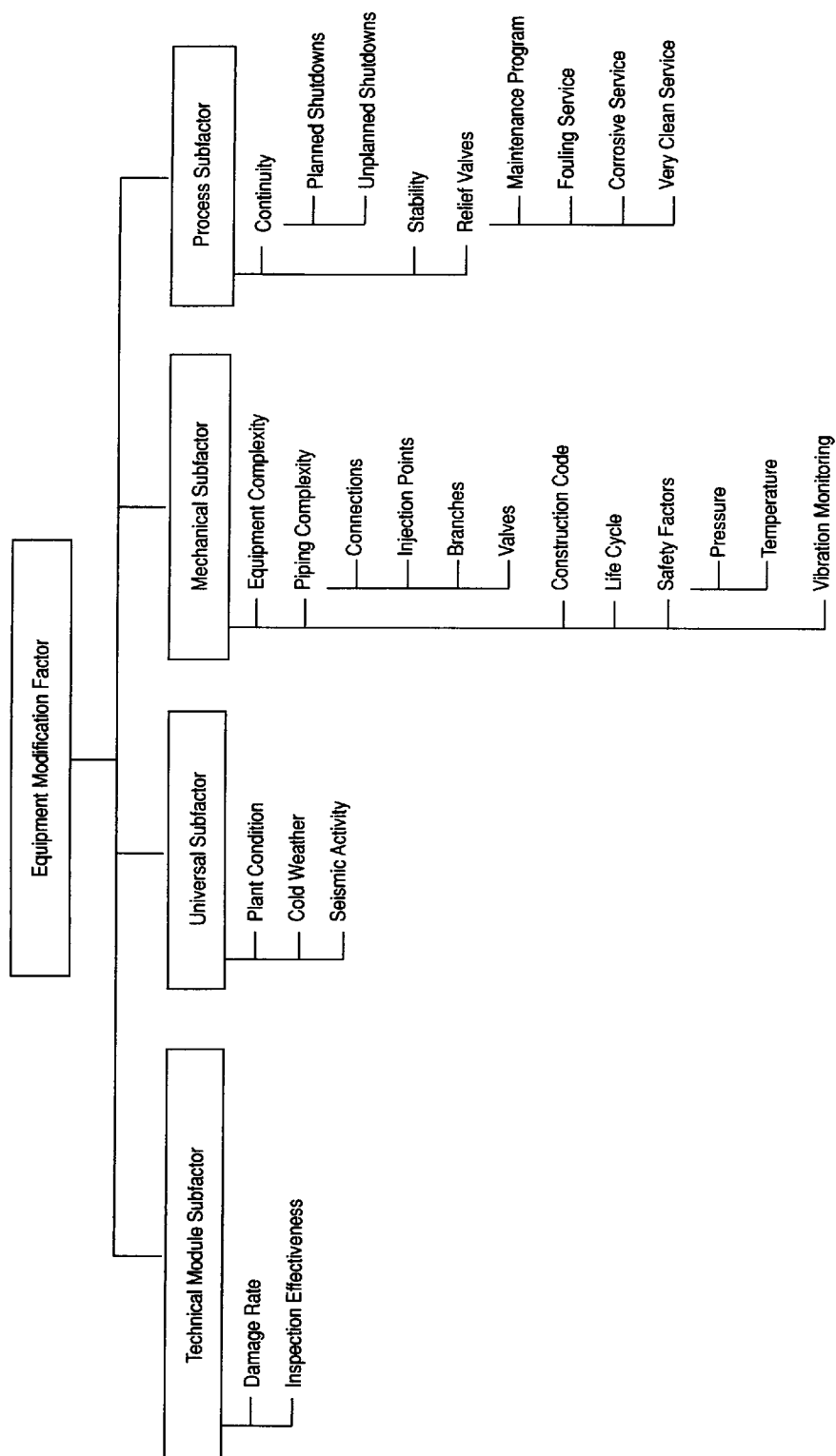


Figure 8-2—Overview of Equipment Modification Factor

are identified, this system results in a negative numeric value for the equipment item (and therefore a lower than generic failure frequency), all other factors being equal.

If the summed equipment factor is a negative value, it is converted as described below to develop a positive final equipment modification factor.

Section 9 defines the required data for a RBI study and recommends sources for obtaining the data. It also includes a sample datasheet that can be used to gather the information needed to establish FE.

After the subfactors have been analyzed, the numeric values for all the separate determinations are summed to yield a final numeric value for the equipment item. The final equipment modification factor is based on this value. The sum can be either positive or negative, and it will normally range from -10 to +20, although at the start of the program, the factor can be much higher when a piece of equipment has a high damage rate and a relatively ineffective inspection history. The final numeric value is converted to an FE as shown in Table 8-2.

The resulting equipment modification factor is unique for each equipment item and is based on the item's specific operating environment.

### 8.3.1 Technical Modules

The Technical Modules are the systematic methods used to assess the effect of specific failure mechanisms on the probability of failure. They serve four functions:

- Screen for the damage mechanisms under normal and upset operating conditions.
- Establish a damage rate in the environment.
- Quantify the effectiveness of the inspection program.
- Calculate the modification factor to be applied to the "generic" failure frequency.

The Technical Module evaluates two categories of information:

- Deterioration rate of the equipment item's material of construction, resulting from its operating environment.
- Effectiveness of the facility's inspection program to identify and monitor the operative damage mechanisms prior to failure.

Inspection techniques required to detect and monitor one failure mechanism may be totally different from those needed for another mechanism. These differences are addressed by creating a separate Technical Module for each damage mechanism. For some damage mechanisms, the rate of damage can be significantly greater under certain non-routine conditions, such as temperature excursions or abnormal changes in the concentrations of a particular contaminant. These conditions often occur during process upsets or startups and shutdowns. The Technical Module accounts for such conditions and modifies the probability of failure accordingly. An example of the process for developing a Technical Module is presented in

Table 8-2—Converted Equipment Modification Factor

| If the sum of numeric values is . . . | the FE is . . .                                           |
|---------------------------------------|-----------------------------------------------------------|
| Less than -1.0                        | The reciprocal of the absolute value of the numeric value |
| -1.0 to +1.0                          | 1.0                                                       |
| Greater than +1.0                     | Equal to the numeric value                                |

this section. The fully developed Technical Modules are presented in Appendices F through N.

The user of the RBI system should not consider procedures described in this chapter to be all-inclusive or inviolable. This chapter is intended to establish a method for the systematic and reproducible analysis of the factors that affect failure frequency. At the same time, the RBI study should be conducted under the oversight of a person or persons with appropriate technical expertise.

Analyzing the effect of in-service damage and inspection on the probability of failure involves the following seven steps:

- Screen for damage mechanisms and establish expected damage rate.
- Determine the confidence level in the damage rate.
- Determine the effectiveness of inspection programs in confirming damage levels and damage rates.
- Calculate the effect of the inspection program on improving the confidence level in the damage rate.
- Calculate the probability that a given level of damage will exceed the damage tolerance of the equipment and result in failure.
- Calculate the technical module subfactor.
- Calculate the composite technical module subfactor for all damage mechanisms.

This section presents an overview of the approach following the example of a Technical Module for general internal corrosion. General corrosion is defined as uniform thinning over a substantial portion of the equipment wall. Different technical modules will deal with localized corrosion because of the higher variability of localized corrosion rates, the greater difficulty of detecting localized corrosion, and the ability of pressure equipment to tolerate deeper flaws if the affected area is small enough. Continuing the example of general corrosion, the following pressure vessel will be used as a case study to demonstrate the methods.

| Vessel:                | Atmospheric Overhead Accumulator |
|------------------------|----------------------------------|
| Material:              | SA 285-Gr.C                      |
| Thickness:             | $\frac{3}{8}$ in.                |
| Design Pressure:       | 50 psig                          |
| Corrosion Allowance:   | $\frac{3}{16}$ in.               |
| Diameter:              | 6 ft 6 in.                       |
| Design Corrosion Rate: | 10 mpy                           |
| Age:                   | 6 years                          |
| Prior Inspection Data: | none                             |

The seven steps of the analysis are described below.

### 8.3.1.1 Screen for Damage Mechanism and Establish Expected Damage Rate

The screening step consists of evaluating the combinations of process conditions and construction materials for each equipment item, to determine what damage mechanisms are potentially active. If no damage mechanisms are found, a technical module subfactor of -2 is applied to that specific piece of equipment, giving a reduction from the generic probability of failure. For the general corrosion technical module, two screening questions are used:

- a. Is the corrosion rate known to be less than 1 mpy? or
- b. Is the equipment designed with a corrosion allowance?

If the answer to the first question is no, or alternatively, if the answer to the second question is yes, the analyst is directed to proceed with the evaluation of the equipment item.

Where a damage mechanism is identified, the rate of damage progression is generally known or can be estimated for process plant equipment. Sources of damage rate information include:

- a. Published data.
- b. Laboratory testing.
- c. In-situ testing.
- d. Experience with similar equipment.
- e. Previous inspection data.

Supplements to the technical modules are being developed for specific materials-environment combinations, and references describing the specific mechanisms are provided.

Example: For general internal corrosion, the damage rate is the corrosion rate used in an API 510 or API 570 calculation to determine the remaining life and the inspection frequency. In some cases, a measured rate of corrosion may not be available. The Technical Modules will provide default values, typically derived from published data or from experience with similar processes, to use until inspection results are available.

Case Study: In our pressure vessel example, the screening step has confirmed that the process would be expected to cause general internal corrosion in the vessel. With no inspection data, the design corrosion data of 10 mpy is the best estimate available for the damage rate.

### 8.3.1.2 Determine the Confidence Level in the Damage Rate

The damage rate in process equipment is often not known with certainty. The ability to state the rate of damage precisely is limited by equipment complexity, process and metallurgical variations, inaccessibility for inspection, and limitations of inspection and test methods.

The uncertainty in the expected damage rate can be determined from historical data on the frequency with which various damage rates occur. A realistic understanding of the

uncertainty in expected damage rates will include consideration of case histories from a variety of similar processes and equipment. The best information will come from operating experiences where the conditions that led to the observed damage rate could realistically be expected to occur in the equipment under consideration. Other sources of information could include databases of plant experience or reliance on expert opinion. The latter method is used most often, since plant databases, where they exist, usually do not contain sufficiently detailed information.

Example: Economical equipment design usually requires internal corrosion rates of less than five mils per year. However, higher rates are sometimes observed. It is not very unusual to observe corrosion rates twice what was expected or previously observed. Usually these higher rates are detected during inspections, but sometimes the occurrence of higher-than-expected corrosion rates is not detected until failure of the pressure boundary of the process occurs.

Observed less frequently are corrosion rates as much as four times the expected rate. Rarely are corrosion rates for uniform corrosion more than four times the rate expected. (Localized corrosion can be significantly more variable and thus must be evaluated in a separate technical module.) The default values provided here are expected to apply to many plant processes. Notice that the uncertainty in the corrosion rate varies, depending on the source and quality of the corrosion rate data.

For general internal corrosion, the reliability of the information sources used to establish a corrosion rate can be put into the following three categories:

#### 8.3.1.2.1 Low Reliability Information Sources for Corrosion Rates

- a. Published data.
- b. Corrosion rate tables.
- c. "Default" values.

Although they are often used for design decisions, the actual corrosion rate that will be observed in a given process situation may significantly differ from the design value.

#### 8.3.1.2.2 Moderate Reliability Information Sources for Corrosion Rates

- a. Laboratory testing with simulated process conditions.
- b. Limited in-situ corrosion coupon testing.

Corrosion rate data developed from sources that simulate the actual process conditions usually provide a higher level of confidence in the predicted corrosion rate.

#### 8.3.1.2.3 High Reliability Information Sources for Corrosion Rates

- a. Extensive field data from thorough inspections.

b. Coupon data, reflecting five or more years of experience with the process equipment (assuming no change in process conditions has occurred).

If enough data are available from actual process experience, there is little likelihood that the actual corrosion rate will greatly exceed the expected value under normal operating conditions.

Table 8-3 expresses the degree of confidence that the true damage rate falls into the listed damage rate ranges, based on the reliability of the damage rate data.

**Case Study:** In our pressure vessel example, the anticipated corrosion rate is based on the design information. In this case, published data were consulted, and the designer had significant experience with the process. Confidence in the corrosion rate information is based on the judgment that the data is "low reliability."

### 8.3.1.3 Determine the Effectiveness of Inspection Programs in Confirming Damage Levels and Damage Rates

Inspection programs (the combination of NDE methods such as visual, ultrasonic, etc., used to determine the equipment condition) vary in their effectiveness for locating and sizing damage, and thus for determining damage rates. Limitations in the ability of a program to improve confidence in the damage level result from the inability to inspect 100% of the areas subject to damage, and from inherent limitations of some test methods to detect and quantify damage. Probability-of-detection curves provide some information on inherent test limitations and are discussed in further detail in 8.2.3.

The technical modules are based on three damage states which are defined in Table 8-4.

The effectiveness of an inspection program can be quantitatively expressed as the likelihood that the observed damage state (and thus the predicted damage rate) actually represents the true state. As in the previous discussion of damage rate estimates, plant information and experience, together with expert opinion, provide information with which to express the inspection program's effectiveness.

Table 8-3—Confidence in Predicted Damage Rate

| Actual Damage Rate Range         | Low Reliability Data | Moderate Reliability Data | High Reliability Data |
|----------------------------------|----------------------|---------------------------|-----------------------|
| Predicted rate or less           | 0.5                  | 0.7                       | 0.8                   |
| Predicted rate to two times rate | 0.3                  | 0.2                       | 0.15                  |
| Two to four times predicted rate | 0.2                  | 0.1                       | 0.05                  |

In general, inspection programs are classified into one of five categories:

- Highly effective.
- Usually effective.
- Fairly effective.
- Poorly effective.
- Ineffective.

At this point, the BRD will continue illustrating development of the Technical Module with the general examples of internal corrosion.

Section 8.2.2 explains how the estimate of inspection effectiveness is developed and how categories are assigned. Example: For general internal corrosion, the damage rate can be determined very effectively with a thorough inspection, but even "spot" random measurements yield considerable information since the corrosion rate usually does not vary much except over fairly large areas.

It is important to recognize that inspection codes and practices expect thickness measurements to be taken at repeatable locations to improve the accuracy of corrosion rate calculations.

Three inspection programs are described and their effectiveness category are defined in Table 8-4.

Default values, based on expert opinion, are provided in Table 8-6, indicating the level of confidence that each of the three levels of inspection effectiveness will accurately determine the corrosion rate.

**Case Study:** In our pressure vessel example, no inspections have been performed.

Table 8-4—Generic Descriptions of Damage State Categories

| Damage State Category                                                                                                                                                                                           | Example—General Corrosion                                                                                                                                       |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Damage State 1</b><br>The damage in the equipment is no worse than what is expected based on damage rate models or experience.                                                                               | The rate of general corrosion is less than or equal to the rate predicted by past inspection records, or historical data if no inspections have been performed. |
| <b>Damage State 2</b><br>The damage in the equipment is "somewhat" worse than anticipated. This level of damage is sometimes seen in similar equipment items.                                                   | The rate of general corrosion is as much as twice the predicted rate.                                                                                           |
| <b>Damage State 3</b><br>The damage in the equipment is "considerably" worse than anticipated. This level of damage is rarely seen in similar equipment items, but has been observed on occasion industry wide. | The rate of general corrosion is as much as four times the predicted rate.                                                                                      |

Table 8-5—Inspection Effectiveness for General Internal Corrosion

| Qualitative Inspection Effectiveness Category                                                                                                  | General Corrosion Examples                                                                                              |
|------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------|
| <b>Highly Effective</b><br>Inspection methods correctly identify the anticipated in-service damage in nearly every case (90%).                 | Assessment of general corrosion by complete internal visual examination coupled with ultrasonic thickness measurements. |
| <b>Usually Effective</b><br>The inspection methods will correctly identify the actual damage state most of the time (70%).                     | Assessment of general corrosion by partial internal visual examination coupled with ultrasonic thickness measurements.  |
| <b>Fairly Effective</b><br>The inspection methods will correctly identify the true damage state about half of the time (50%).                  | Assessment of general corrosion by external spot ultrasonic thickness measurements.                                     |
| <b>Poorly Effective</b><br>The inspection methods will provide little information to correctly identify the true damage state (40%).           | Assessment of general corrosion by hammer testing, telltale holes.                                                      |
| <b>Ineffective</b><br>The inspection method will provide no or almost no information that will correctly identify the true damage state (33%). | Assessment of general internal corrosion by external visual examination.                                                |

Table 8-6—General Corrosion—Inspection Effectiveness

| Damage Rate State | Range of actual damage rate       | Likelihood that inspection result determines the true damage state |                     |                      |                     |
|-------------------|-----------------------------------|--------------------------------------------------------------------|---------------------|----------------------|---------------------|
|                   |                                   | Poorly/<br>Ineffective                                             | Fairly<br>Effective | Usually<br>Effective | Highly<br>Effective |
| 1                 | Measured rate or less             | 0.33                                                               | 0.5                 | 0.7                  | 0.9                 |
| 2                 | Measured rate to 2x measured rate | 0.33                                                               | 0.3                 | 0.2                  | 0.09                |
| 3                 | 2x to 4x measured rate            | 0.33                                                               | 0.2                 | 0.1                  | 0.01                |

### 8.3.1.4 Calculate the Effect of the Inspection Program on Improving the Confidence Level in the Damage Rate

At this point, the Technical Module has defined the need to determine the probability of a given damage state occurring in the equipment item being evaluated. The problem is of the general form: "Given an expectation of a given state, and given that a test can be performed to improve the confidence level in the expectation of that state, what is the expectation of the state after the test is performed, if the test does not yield conclusive results?"

Problems of this type can be solved using a widely recognized statistical method called Bayes' Theorem. This theorem combines the prior probabilities  $p[A_i]$  (the expected state) with the conditional probabilities,  $p[B_k|A_i]$  (the inspection effectiveness) to yield an expression for the probability that an equipment item is in any state  $A_i$  given that the item was observed to be in state  $A_k$  which results in observation  $B_k$ .

$$p[A_i|B_k] = \frac{p[B_k|A_i]p[A_i]}{\sum_{j=1}^n p[B_k|A_j]p[A_j]} \quad (8.1)$$

The probabilities,  $p[A_i|B_k]$  are called posterior probabilities.

For those unfamiliar with the equation, it can be expressed as follows: "the probability of the true state, given the state of a sample equals [(the probability of the sample state, given the true state) times (the prior probability of the state)] divided by [the sum over all states of (the probability of the sample state, given the true state) times (the prior probability of the state)]".

The power of the theorem is that it provides a formal means of incorporating an uncertain inspection result with information on the expected condition based on an analysis or opinion.

Given an expectation of the likelihoods of different damage rates, and given inspection results that tend to indicate one rate or another, Bayes' Theorem is used to update the prior expectations.

The inspection frequency and the total number of inspections are used to perform the inspection updating. The "value" of an inspection in improving the certainty of the damage rate can clearly be determined using Bayes' Theorem. The updated confidence in damage rates is then used to calculate the amount of damage that may be present in the equipment.

Example: For the above examples of expected damage rates and inspection effectiveness, the updated confidence in the damage rates after inspection can be determined:

- Corrosion rates for a new plant are estimated from corrosion tables
- A thorough inspection is conducted after some time in operation
- The expected corrosion rate is confirmed

As shown in Table 8-7, the confidence in the expected corrosion rate can be updated by Bayes' Theorem:

Case Study: In our pressure vessel example, the first inspection is determined to be a usually effective inspection.

Table 8-7 is shown in graphic form in Figure 8-3. Note that the inspection serves to reduce the uncertainty in the expected corrosion rate.

### 8.3.1.5 Calculate the Frequency at which a Given Level of Damage Will Exceed the Damage Tolerance of the Equipment and Result in Failure

The potential damage rates, represented by the uncertainty in the estimated damage rate, will lead to different levels of damage after a given time in operation. The next step in the

Technical Module is to calculate the frequency of failure associated with a given damage state.

Failure of process equipment with respect to damage states depends on a number of random variables,  $Z_1, Z_2 \dots Z_n$ , such as maximum pressure, maximum crack size, yield strength, or fracture toughness. The space of these quantities is divided into two regions:

- The safe set is the region of the space that contains combinations of the basic variables,  $Z_i$ , that do not result in failure.
- The failure set is the region of this space that contains all combinations of the variables,  $Z_i$ , that result in failure.

A mode of failure is defined by a limit state function  $g(Z_i)$ . The surface described by  $g(Z_i) = 0$  divides the variable into the safe set where  $g(Z_i) > 0$  and the failure set where  $g(Z_i) < 0$ . For example, the limit state function for a pressure vessel might be:

$$g = S - L$$

where

$S$  = strength,

$L$  = load.

Table 8-7—Confidence in Damage Rate After Inspection

| Damage Rate State | Range of Damage Rate              | After a Fairly Effective Inspection | After a Usually Effective Inspection | After a Highly Effective Inspection |
|-------------------|-----------------------------------|-------------------------------------|--------------------------------------|-------------------------------------|
| 1                 | Measured rate or less             | 0.66                                | 0.814                                | 0.940                               |
| 2                 | Measured rate to 2x measured rate | 0.24                                | 0.140                                | 0.056                               |
| 3                 | 2 to 4x measured rate             | 0.10                                | 0.046                                | 0.004                               |

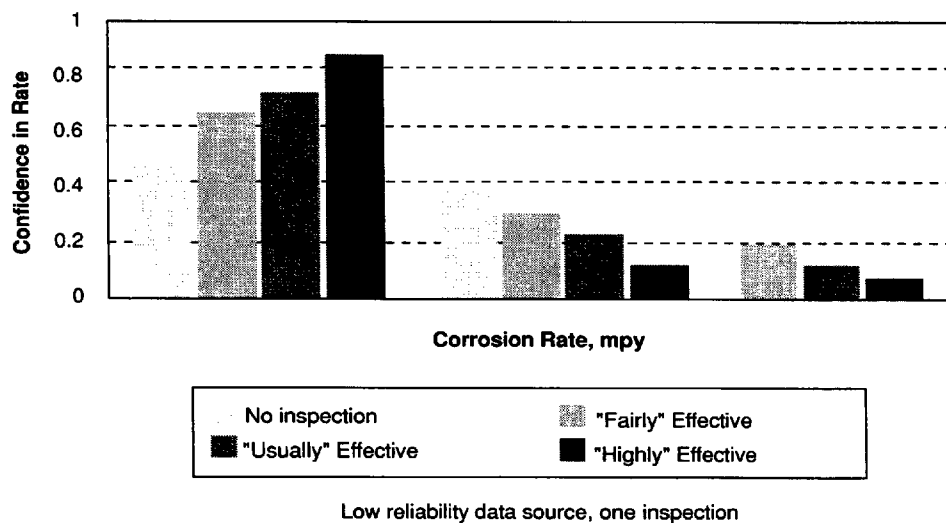


Figure 8-3—Damage Rate Confidence-Inspection Updating vs. Inspection Effectiveness

Whenever the load exceeds the strength, the vessel fails and  $g(S, L) < 0$ .

For a failure mode that is described by a limit state function, the probability of failure is the probability of being in the failure set,  $g(Z_i) < 0$ . Several approaches can be used to calculate the probability of failure. For RBI, since this is a decision-making tool, relatively simple reliability index methods have been chosen.

The procedure used here is to "calibrate" the calculated probability of failure to the generic failure frequency by adjusting the inputs to the reliability index so that an "acceptable" level of damage corresponds to the generic failure frequency. This "calibrated" reliability index model is used to calculate a failure frequency for higher damage states.

Example: For the case of general corrosion, the mode of failure is ductile overload, which occurs when the flow stress in a thinned wall is exceeded by the stress caused by the applied loads.

For the example above with different potential corrosion rates, the damage state (wall loss) is calculated for each rate. Then the frequency of failure for each state is calculated using a simple reliability index method.

Case Study: For the pressure vessel example, remember that the vessel has been in service for six years. Table 8.8 shows the probabilities of failure that correspond to the three different damage states.

### 8.3.1.6 Calculate the Technical Module Subfactor

The next step in the Technical Module is to calculate the "technical module subfactor" that is used to compare the frequency of failure due to the damage state, to the generic failure frequency for the equipment type under consideration. The technical module subfactor is the ratio of the frequency of failure due to damage, to the generic failure frequency, times the likelihood that the damage level is present.

The frequency of failure for the damage state is divided by the "generic" failure frequency. The resulting ratio shows how much more likely the equipment being analyzed is to fail as a result of the given damage state than is the "generic" equipment item. This ratio is then multiplied by the likelihood that the damage state exists, as updated by inspection information.

Case Study: For the pressure vessel subject to general corrosion, Table 8-9 shows the calculated technical module subfactor. As an illustration of the effect of inspection updating, the subfactor is calculated for two cases:

- The vessel is six years old and has not yet been inspected.
- The vessel is six years old and has received one inspection rated "usually effective."

Note: the reduction in the technical module subfactor following the inspection.

The table is illustrated in graphic form in Figure 8-4. Note that the inspection serves to significantly reduce the likelihood of the higher damage states.

The technical module subfactor is the sum of the partial damage factors for the different damage states. The lowest that a technical module subfactor can be is 1.0, since in the risk analysis no credit is given for the absence of any one particular type of damage.

### 8.3.1.7 Calculate the Composite Technical Module Subfactor for all Damage Mechanisms

A technical module subfactor is calculated for each damage mechanism that is active in the piece of equipment. To calculate the composite (total) technical module subfactor for the equipment, all of the individual subfactors are added. This approach has the advantage of showing a quantitative change

Table 8-8—Calculated Frequency of Failure for Different Damage States

| Damage State | Corrosion Rate | Wall Loss | Remaining Wall | Frequency of Failure |
|--------------|----------------|-----------|----------------|----------------------|
| 1            | 0.010 in./yr   | 0.06      | 0.315          | $8 \times 10^{-6}$   |
| 2            | 0.020 in./yr   | 0.12      | 0.255          | $2 \times 10^{-5}$   |
| 3            | 0.040 in./yr   | 0.24      | 0.135          | $5 \times 10^{-3}$   |

Table 8-9—Calculated Technical Module Subfactor

| Damage State                      | Probability of Failure | "Generic" Probability of Failure | Ratio to "Generic" | Likelihood of Damage (before inspection) | Partial Damage Factor (no insp.) | Likelihood of Damage (after inspection) | Partial Damage Factor (1 insp.) |
|-----------------------------------|------------------------|----------------------------------|--------------------|------------------------------------------|----------------------------------|-----------------------------------------|---------------------------------|
| 1                                 | $8 \times 10^{-6}$     | $1 \times 10^{-4}$               | 0.08               | 0.5                                      | 0.04                             | 0.81                                    | 0.06                            |
| 2                                 | $2 \times 10^{-5}$     | $1 \times 10^{-4}$               | 0.2                | 0.3                                      | 0.06                             | 0.14                                    | 0.03                            |
| 3                                 | $5 \times 10^{-3}$     | $1 \times 10^{-4}$               | 50                 | 0.2                                      | 10                               | 0.05                                    | 2                               |
| Total Technical Module Sub-Factor |                        |                                  |                    |                                          | 10                               |                                         | 2                               |



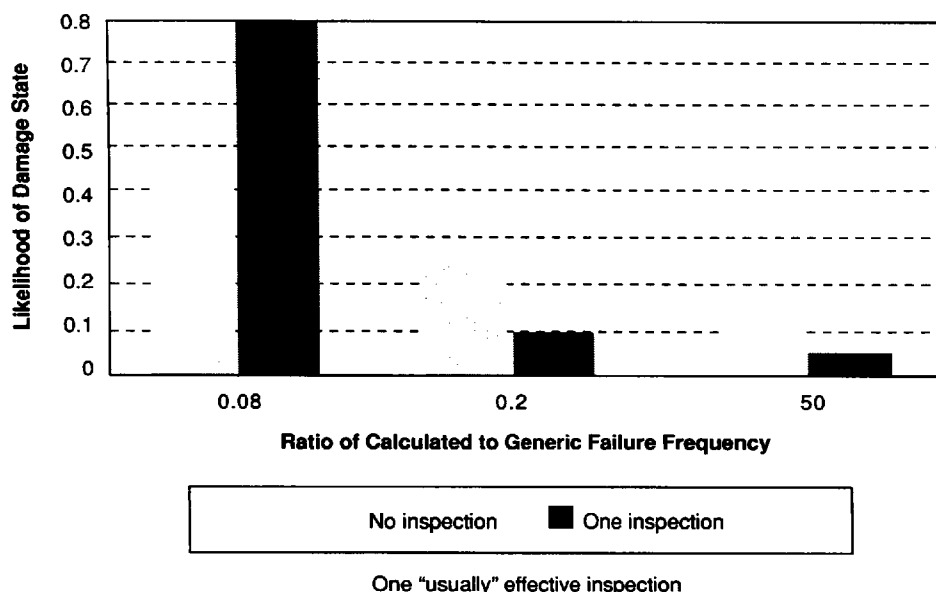


Figure 8-4—Failure Frequency-Inspection Influence on Calculated Frequency

in the total factor if any one of the subfactors changes. The approach also reflects that different damage mechanisms are often not completely independent. That is, damage caused by one mechanism may influence the severity of damage caused by another (for example, stress corrosion cracking may begin at stress concentrators caused by pitting corrosion).

### 8.3.1.8 Using Measured Corrosion Rates in the Absence of Expert Opinion or Data

A serious weakness can exist in the application of RBI technology as outlined in this chapter if the source of corrosion rate data is not properly considered. In the model presented, corrosion rates are always assumed to have a potential to be higher than expected, unless this potential has been eliminated by thorough or multiple inspections. The technical module subfactor tables for thinning are based on a simplified version of Bayesian updating that assumes that expert opinion will generally be used to establish corrosion rates. Since such expert opinions are fairly reliable, and generally err on the conservative side, the method used will also generally err on the conservative side. However, many plants do not have or use expert opinion as the basis for corrosion rates, but instead rely entirely upon thickness measurements taken by technicians who have little or no knowledge of process corrosion. In such a case, the corrosion rate measured can be much less than the actual corrosion rate (depending on the degree to which the corrosion is localized and upon the effectiveness level of the inspection). In such cases, it is strongly suggested that corrosion rate estimates be made by knowledgeable per-

sons using data or tools such as the Technical Module Supplements.

Two methods are suggested for establishing corrosion rates in the absence of corrosion data, expert opinion or prior knowledge of the type and rate of corrosion occurring in a particular system.

#### 8.3.1.8.1 Method #1—Simplified Approach

When a corrosion rate is to be used for Risk-Based Inspection in the absence of corrosion rate data or information about localized corrosion, the question usually arises: "How much inspection is needed to determine the rate and type of corrosion?" It may be risky to use spot external thickness measurements for such purposes, but it may be a waste of money to use more thorough methods if they are not needed. The following guidelines are offered to aid in a decision.

a. Localized corrosion likely: Use a "highly effective" method to determine positively if localized corrosion is occurring. These methods are described in the Technical Module for Thinning, Appendix F. Process streams that should be in this category include any that contain water or other conductive fluid plus:

1. Chlorides or other halides.
2. Sulfur compounds.
3. Organic acids.

b. Localized corrosion possible: Use a "usually" effective method to determine positively if localized corrosion is occurring. These methods are described in the Technical Module for Thinning, Appendix F. Process streams that

should be in this category include any that do not contain water or other conductive fluid\* but do contain:

1. Chlorides or other halides.
2. Sulfur compounds.
3. Organic acids.

c. Localized corrosion unlikely: Use a "fairly effective" method to determine positively if localized corrosion is occurring. These methods are described in the Technical Module for Thinning, Appendix F. Process streams that should be in this category include any that do not contain water or other conductive fluid and also do not contain:

1. Chlorides or other halides.
2. Sulfur compounds.
3. Organic acids.

"Other conductive fluid" refers to some classes of organic chemicals that, like water, can conduct electricity. These fluids (e.g. dimethyl formamide, n-butyl alcohol, are not normally part of refinery process streams, but are present in some chemical plants). As a general rule, fluids with a conductivity of less than  $10^{-7}$  ohm<sup>-1</sup> cm<sup>-1</sup> are nonconductive and therefore tend to be noncorrosive.

### 8.3.1.8.2 Method #2—Rigorous Approach

There sometimes arises a situation in which corrosion data, expert opinion or prior knowledge of the type and rate of corrosion do not agree with the inspection findings. If the inspection finds higher rates of corrosion than expected, then there is little doubt that these higher rates exist and they should be used unless they are attributed to some process upset or unusual condition that has been corrected. On the other hand, if the inspection data shows lower rates of corrosion than expected, then a conflict arises about which data is correct.

If the measured corrosion rates are lower than the expected corrosion rate, then repeated observations of these lower rates must be used to "override" the expected rate, much in the same way that repeated inspections eliminate the possibilities of higher corrosion rates using the current methods. As more inspections are performed, or more highly effective inspections are performed, the corrosion rate to be used approaches the measured rate from the higher expected rate. The corrosion rate to be used will depend on the number and types of inspections, how much lower than the expected rate is the measured rate, and also upon the confidence level of the expert opinion or data that is used to establish expected rates.

Bayesian updating was used to generate the following tables. A factor is looked up from the table based on the number and types of inspections. This factor is multiplied by the measured rate to generate the rate that should be entered in the program.

The degree to which there is a dispute between the expected and measured rates depends in part upon the confidence that can be placed on the expected rates. In the fol-

lowing tables, 8-9 through 8-11, the confidence level is described in one of three ways:

- a. High—Opinion or data is very slightly conservative, lower rates are not expected.
- b. Medium—Opinion or data is somewhat conservative, some chance of lower rates is recognized.
- c. Low—Opinion or data is highly conservative, significant chance of lower rates is recognized.

Example: Corrosion rate data for a piping system is well established from performance of similar systems, and is supported by published data and laboratory tests. The expected maximum corrosion rate is 10 mpy, and it is known that the corrosion is often highly localized. A contractor takes spot thickness measurements and reports a corrosion rate of 1 mpy. Obviously, there is reason to be skeptical about the data. Since the contractor took only spot measurements and is not especially knowledgeable about where to take them, the inspection effectiveness is judged as "poorly effective." In Table 8-12 the factor for 1 poorly effective inspection resulting in a measurement of  $1/10$  the expected rate for a high confidence expected rate is 8.3. This factor is multiplied by the measured rate of 1 mpy yields an input rate of 8.3 mpy. In other words, the data from the measurement has not successfully changed the expert opinion significantly. Note that repeated inspections and more highly effective inspections (if they continue to observe the lower corrosion rate) will result in the RBI input corrosion rate approaching the measured rate. The factors in Tables 8-10 and 8-11 are used similarly.

### 8.3.2 Universal Subfactor

The universal subfactor covers conditions that equally affect all equipment items in the facility. As a result, the information concerning these conditions needs to be collected and recorded only once. The numeric values assigned for each of the three elements of the subfactor are applied equally to all equipment items.

As shown in Figure 8-2, the universal subfactor includes the following elements:

- a. Plant condition.
- b. Cold weather operation.
- c. Seismic activity.

#### 8.3.2.1 Plant Condition

This element considers the current condition of the facility being evaluated. The ranking should be based on the professional judgment of the observer, when considering the following characteristics:

- a. The general appearance of the plant, as assessed during a plant walk through. Factors to observe include:
  1. The overall state of housekeeping.
  2. Evidence of temporary repairs, particularly if it appears that the "temporary" condition has been in place for an extended period.

Table 8-10—Measured Corrosion Rates Approximately  $\frac{1}{2}$  of the Expected Rate

| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{2}$ of Expected; Confidence = High   |                     |         |        |        |
|--------------------------------------------------------------------------------------|---------------------|---------|--------|--------|
| No. of Inspections                                                                   | Level of Inspection |         |        |        |
|                                                                                      | Highly              | Usually | Fairly | Poorly |
| 1                                                                                    | 1.4                 | 1.8     | 1.9    | 1.9    |
| 2                                                                                    | 1.0                 | 1.5     | 1.8    | 1.9    |
| 3                                                                                    | 1.0                 | 1.1     | 1.7    | 1.9    |
| 4                                                                                    | 1.0                 | 1.0     | 1.5    | 1.8    |
| 5                                                                                    | 1.0                 | 1.0     | 1.3    | 1.8    |
| 6                                                                                    | 1.0                 | 1.0     | 1.2    | 1.7    |
| 7                                                                                    | 1.0                 | 1.0     | 1.1    | 1.7    |
| 8                                                                                    | 1.0                 | 1.0     | 1.1    | 1.6    |
| 9                                                                                    | 1.0                 | 1.0     | 1.0    | 1.6    |
| 10                                                                                   | 1.0                 | 1.0     | 1.0    | 1.5    |
| 11                                                                                   | 1.0                 | 1.0     | 1.0    | 1.4    |
| 12                                                                                   | 1.0                 | 1.0     | 1.0    | 1.3    |
| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{2}$ of Expected; Confidence = Medium |                     |         |        |        |
| No. of Inspections                                                                   | Level of Inspection |         |        |        |
|                                                                                      | Highly              | Usually | Fairly | Poorly |
| 1                                                                                    | 1.1                 | 1.5     | 1.7    | 1.8    |
| 2                                                                                    | 1.0                 | 1.2     | 1.5    | 1.7    |
| 3                                                                                    | 1.0                 | 1.0     | 1.4    | 1.6    |
| 4                                                                                    | 1.0                 | 1.0     | 1.2    | 1.6    |
| 5                                                                                    | 1.0                 | 1.0     | 1.1    | 1.5    |
| 6                                                                                    | 1.0                 | 1.0     | 1.1    | 1.4    |
| 7                                                                                    | 1.0                 | 1.0     | 1.0    | 1.4    |
| 8                                                                                    | 1.0                 | 1.0     | 1.0    | 1.3    |
| 9                                                                                    | 1.0                 | 1.0     | 1.0    | 1.2    |
| 10                                                                                   | 1.0                 | 1.0     | 1.0    | 1.2    |
| 11                                                                                   | 1.0                 | 1.0     | 1.0    | 1.2    |
| 12                                                                                   | 1.0                 | 1.0     | 1.0    | 1.1    |
| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{2}$ of Expected; Confidence = Low    |                     |         |        |        |
| No. of Inspections                                                                   | Level of Inspection |         |        |        |
|                                                                                      | Highly              | Usually | Fairly | Poorly |
| 1                                                                                    | 1.1                 | 1.2     | 1.4    | 1.4    |
| 2                                                                                    | 1.0                 | 1.1     | 1.2    | 1.4    |
| 3                                                                                    | 1.0                 | 1.0     | 1.1    | 1.3    |
| 4                                                                                    | 1.0                 | 1.0     | 1.1    | 1.3    |
| 5                                                                                    | 1.0                 | 1.0     | 1.0    | 1.2    |
| 6                                                                                    | 1.0                 | 1.0     | 1.0    | 1.2    |
| 7                                                                                    | 1.0                 | 1.0     | 1.0    | 1.1    |
| 8                                                                                    | 1.0                 | 1.0     | 1.0    | 1.1    |
| 9                                                                                    | 1.0                 | 1.0     | 1.0    | 1.1    |
| 10                                                                                   | 1.0                 | 1.0     | 1.0    | 1.1    |
| 11                                                                                   | 1.0                 | 1.0     | 1.0    | 1.1    |
| 12                                                                                   | 1.0                 | 1.0     | 1.0    | 1.1    |

Table 8-11—Measured Corrosion Rates Approximately  $\frac{1}{4}$  of the Expected Rate

| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{4}$ of Expected; Confidence = High   |                     |         |        |        |
|--------------------------------------------------------------------------------------|---------------------|---------|--------|--------|
| No. of Inspections                                                                   | Level of Inspection |         |        |        |
|                                                                                      | Highly              | Usually | Fairly | Poorly |
| 1                                                                                    | 2.0                 | 3.4     | 3.6    | 3.7    |
| 2                                                                                    | 1.1                 | 2.4     | 3.4    | 3.7    |
| 3                                                                                    | 1.0                 | 1.4     | 3.0    | 3.6    |
| 4                                                                                    | 1.0                 | 1.1     | 2.5    | 3.5    |
| 5                                                                                    | 1.0                 | 1.0     | 2.0    | 3.3    |
| 6                                                                                    | 1.0                 | 1.0     | 1.5    | 3.2    |
| 7                                                                                    | 1.0                 | 1.0     | 1.3    | 3.0    |
| 8                                                                                    | 1.0                 | 1.0     | 1.1    | 2.8    |
| 9                                                                                    | 1.0                 | 1.0     | 1.1    | 2.5    |
| 10                                                                                   | 1.0                 | 1.0     | 1.0    | 2.3    |
| 11                                                                                   | 1.0                 | 1.0     | 1.0    | 2.1    |
| 12                                                                                   | 1.0                 | 1.0     | 1.0    | 1.9    |
| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{4}$ of Expected; Confidence = Medium |                     |         |        |        |
| No. of Inspections                                                                   | Level of Inspection |         |        |        |
|                                                                                      | Highly              | Usually | Fairly | Poorly |
| 1                                                                                    | 1.3                 | 2.4     | 2.9    | 3.1    |
| 2                                                                                    | 1.0                 | 1.5     | 2.4    | 3.0    |
| 3                                                                                    | 1.0                 | 1.1     | 1.9    | 2.8    |
| 4                                                                                    | 1.0                 | 1.0     | 1.6    | 2.6    |
| 5                                                                                    | 1.0                 | 1.0     | 1.3    | 2.4    |
| 6                                                                                    | 1.0                 | 1.0     | 1.2    | 2.1    |
| 7                                                                                    | 1.0                 | 1.0     | 1.1    | 1.9    |
| 8                                                                                    | 1.0                 | 1.0     | 1.0    | 1.8    |
| 9                                                                                    | 1.0                 | 1.0     | 1.0    | 1.6    |
| 10                                                                                   | 1.0                 | 1.0     | 1.0    | 1.5    |
| 11                                                                                   | 1.0                 | 1.0     | 1.0    | 1.4    |
| 12                                                                                   | 1.0                 | 1.0     | 1.0    | 1.3    |
| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{4}$ of Expected; Confidence = Low    |                     |         |        |        |
| No. of Inspections                                                                   | Level of Inspection |         |        |        |
|                                                                                      | Highly              | Usually | Fairly | Poorly |
| 1                                                                                    | 1.1                 | 1.5     | 1.9    | 2.1    |
| 2                                                                                    | 1.0                 | 1.1     | 1.6    | 2.0    |
| 3                                                                                    | 1.0                 | 1.0     | 1.3    | 1.8    |
| 4                                                                                    | 1.0                 | 1.0     | 1.2    | 1.6    |
| 5                                                                                    | 1.0                 | 1.0     | 1.1    | 1.5    |
| 6                                                                                    | 1.0                 | 1.0     | 1.1    | 1.4    |
| 7                                                                                    | 1.0                 | 1.0     | 1.0    | 1.3    |
| 8                                                                                    | 1.0                 | 1.0     | 1.0    | 1.3    |
| 9                                                                                    | 1.0                 | 1.0     | 1.0    | 1.2    |
| 10                                                                                   | 1.0                 | 1.0     | 1.0    | 1.2    |
| 11                                                                                   | 1.0                 | 1.0     | 1.0    | 1.1    |
| 12                                                                                   | 1.0                 | 1.0     | 1.0    | 1.1    |

Table 8-12—Measured Corrosion Rates Approximately  $\frac{1}{10}$  of the Expected Rate

| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{10}$ of Expected; Confidence = High   |                     |         |        |        |
|---------------------------------------------------------------------------------------|---------------------|---------|--------|--------|
| No. of Inspections                                                                    | Level of Inspection |         |        |        |
|                                                                                       | Highly              | Usually | Fairly | Poorly |
| 1                                                                                     | 4.2                 | 8.3     | 9.0    | 9.3    |
| 2                                                                                     | 1.2                 | 5.3     | 8.3    | 9.1    |
| 3                                                                                     | 1.0                 | 2.3     | 7.2    | 8.8    |
| 4                                                                                     | 1.0                 | 1.3     | 5.7    | 8.5    |
| 5                                                                                     | 1.0                 | 1.1     | 4.0    | 8.1    |
| 6                                                                                     | 1.0                 | 1.0     | 2.8    | 7.7    |
| 7                                                                                     | 1.0                 | 1.0     | 1.9    | 7.1    |
| 8                                                                                     | 1.0                 | 1.0     | 1.5    | 6.5    |
| 9                                                                                     | 1.0                 | 1.0     | 1.3    | 5.8    |
| 10                                                                                    | 1.0                 | 1.0     | 1.1    | 5.2    |
| 11                                                                                    | 1.0                 | 1.0     | 1.1    | 4.5    |
| 12                                                                                    | 1.0                 | 1.0     | 1.0    | 3.9    |
| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{10}$ of Expected; Confidence = Medium |                     |         |        |        |
| No. of Inspections                                                                    | Level of Inspection |         |        |        |
|                                                                                       | Highly              | Usually | Fairly | Poorly |
| 1                                                                                     | 2.2                 | 5.4     | 7.0    | 7.7    |
| 2                                                                                     | 1.1                 | 2.5     | 5.6    | 7.2    |
| 3                                                                                     | 1.0                 | 1.3     | 4.1    | 6.6    |
| 4                                                                                     | 1.0                 | 1.1     | 2.8    | 6.0    |
| 5                                                                                     | 1.0                 | 1.0     | 2.0    | 5.3    |
| 6                                                                                     | 1.0                 | 1.0     | 1.6    | 4.7    |
| 7                                                                                     | 1.0                 | 1.0     | 1.3    | 4.1    |
| 8                                                                                     | 1.0                 | 1.0     | 1.2    | 3.6    |
| 9                                                                                     | 1.0                 | 1.0     | 1.1    | 3.1    |
| 10                                                                                    | 1.0                 | 1.0     | 1.1    | 2.7    |
| 11                                                                                    | 1.0                 | 1.0     | 1.0    | 2.3    |
| 12                                                                                    | 1.0                 | 1.0     | 1.0    | 2.1    |
| Wtd. Avg. Corr. Rate; Measured Rate = $\frac{1}{10}$ of Expected; Confidence = Low    |                     |         |        |        |
| No. of Inspections                                                                    | Level of Inspection |         |        |        |
|                                                                                       | Highly              | Usually | Fairly | Poorly |
| 1                                                                                     | 1.5                 | 2.7     | 4.0    | 4.8    |
| 2                                                                                     | 1.0                 | 1.5     | 2.9    | 4.2    |
| 3                                                                                     | 1.0                 | 1.1     | 2.1    | 3.7    |
| 4                                                                                     | 1.0                 | 1.0     | 1.6    | 3.2    |
| 5                                                                                     | 1.0                 | 1.0     | 1.4    | 2.8    |
| 6                                                                                     | 1.0                 | 1.0     | 1.2    | 2.5    |
| 7                                                                                     | 1.0                 | 1.0     | 1.1    | 2.2    |
| 8                                                                                     | 1.0                 | 1.0     | 1.1    | 2.0    |
| 9                                                                                     | 1.0                 | 1.0     | 1.0    | 1.8    |
| 10                                                                                    | 1.0                 | 1.0     | 1.0    | 1.7    |
| 11                                                                                    | 1.0                 | 1.0     | 1.0    | 1.5    |
| 12                                                                                    | 1.0                 | 1.0     | 1.0    | 1.4    |

3. Deteriorating paint, excessive number of steam leaks, or other evidence that routine maintenance is being neglected.
- b. Effectiveness of the plant's maintenance program, based on interviews with operations and maintenance personnel. An effective program will:
1. Complete most maintenance activities properly the first time, with few call-backs.
  2. Avoid excessive and growing backlogs of work requests.
  3. Maintain a constructive relationship between maintenance and operations personnel.
- c. Plant layout and construction. In its current condition, the plant should have equipment spacing and orientation that facilitates maintenance and inspection activities.
- The facility should be ranked according to the criteria in Table 8-13.

### 8.3.2.2 Cold Weather Operation

Cold climates impose additional risks on plant operation. Extremely low temperatures inhibit maintenance and inspection activities and can result in reduced operator monitoring of outside equipment.

Winter conditions can also have a direct effect on equipment items. Ice and snow buildup can cause distortion or failure of small lines, instrument and electrical runs, etc. In addition, frozen level controllers, cracked water lines, cracked or frozen water containing deadlegs, and plugged process lines are common winter problems. Cold weather problems can be minimized by proper design, but they cannot be totally eliminated.

As shown in Table 8-14, a penalty is applied based on the lowest average daily temperature at the plant site. Indoor plants should consider lowest indoor temperature.

### 8.3.2.3 Seismic Activity

A plant located in a seismically-active area has a somewhat higher probability of failure than facilities outside such areas, even when the plant has been designed to appropriate standards. The values in Table 8-15 are based on the seismic zones presented in ANSI A58.1, 1982.

### 8.3.3 Mechanical Subfactor

The mechanical subfactor addresses conditions related primarily to the design and fabrication of the equipment item. Information for analysis is normally found on P&ID's, in engineering files, etc. The numeric values generated are often different for each equipment item.

As shown in Figure 8-2, this subfactor is composed of the following five elements:

- a. Complexity.
- b. Construction Code.
- c. Life Cycle.

Table 8-13—Ranking According to Plant Conditions

| Plant Condition                              | Category | Numeric Value |
|----------------------------------------------|----------|---------------|
| Significantly better than industry standards | A        | -1.0          |
| About equal to industry standards            | B        | 0             |
| Below industry standards                     | C        | + 1.5         |
| Significantly below industry standards       | D        | + 4.0         |

Table 8-14—Penalty for Cold Weather Operation

| Winter Temperature | Numeric Value |
|--------------------|---------------|
| Above 40°F         | 0             |
| +20°F to +40°F     | 1.0           |
| -20°F to +20°F     | 2.0           |
| Below -20°F        | 3.0           |

Table 8-15—Penalty for Seismic Zone Operations

| Seismic Zone | Numeric Value |
|--------------|---------------|
| 0 or 1       | 0             |
| 2 or 3       | 1.0           |
| 4            | 2.0           |

- d. Safety Factors.
- e. Vibration Monitoring.

As the discussion shows, some of the elements have multiple sub-elements.

### 8.3.3.1 Complexity

The complexity element is applied differently to equipment and piping which are handled as separate sub-elements.

#### 8.3.3.1.1 Equipment Complexity

The generic failure frequency database does not differentiate for size and complexity for pressure vessels, columns, heat exchangers, etc. One way of judging the complexity of an equipment item and, in most cases, the size of the item is by determining the number of nozzles on it. A nozzle count is easily obtained and can be applied consistently to all types of equipment.

Table 8-16 provides numeric values for a range of nozzle counts for all types of pressure vessels. All nozzles of 2-inches diameter or greater should be included in the count, including nozzles not currently in service. Manways should also be included.

Table 8-16—Nozzle Count versus Numeric Value

| Equipment Item  | Numeric Value |         |         |      |
|-----------------|---------------|---------|---------|------|
|                 | -1.0          | 0       | +1.0    | +2.0 |
| Column—Total    | < 20          | 20 – 35 | 36 – 46 | > 46 |
| Column—Half     | < 10          | 10 – 17 | 18 – 23 | > 23 |
| Compressor      | 2             | 3 – 6   | 7 – 10  | > 10 |
| Exchanger—Shell | < 7           | 7 – 12  | 13 – 16 | > 16 |
| Exchanger—Tube  | < 4           | 4 – 8   | 9 – 11  | > 11 |
| Pump            | —             | 2 – 4   | > 4     | —    |
| Vessel          | < 7           | 7 – 12  | 13 – 16 | > 16 |

### 8.3.3.1.2 Piping Complexity

In a typical RBI study, 60 to 80 percent of the equipment items analyzed will be piping segments. Studies have shown that about one-third of all major equipment failures involve piping, more than any other single equipment category. Therefore, it is as important to be able to differentiate between piping segments as between items in any other equipment category.

The generic database provides a differentiation based on pipe diameter and line length; failure frequency for each diameter is stated in terms of failures/year/foot of length. Further differentiation based on the complexity of the segment is obtained by assigning a Complexity Factor. This factor is the sum of the features of a piping segment that can increase the probability of failure.

Piping complexity is comprised of the following:

- Number of connections.
- Number of injection points.
- Number of branches.
- Number of valves.

### 8.3.3.1.3 Number of Connections

A flanged connection has a much higher probability of leaking than a welded connection. Each flange included in the pipe segment is given a complexity factor of 10. (It is assumed that no process lines in the plant have screwed connections, temporary clamps, or other non-standard fittings. If such connections are in use, a significantly higher factor should be applied, as appropriate.)

### 8.3.3.1.4 Number of Injection Points

Injection points are locations where relatively small quantities of potentially corrosive materials are injected into process streams to control stream composition or other process variables. Examples of injection points include chlorine in reformers, water injection in overhead systems, polysulfide injection in catalytic cracking wet gas, antifoam injections, etc. (Locations where two process streams join, e.g., mixing tees, are not considered injection points.)

Experience has shown that piping in the vicinity of injection points can be subject to accelerated or localized corrosion, even during normal operating conditions. Each injection point adds a complexity factor of 20.

### 8.3.3.1.5 Number of Branches

Any line that tees into the pipe segment being evaluated, other than an injection point, is considered a branch. Drain lines, mixing tees, relief valve branches, etc., should be included. Each branch creates an opportunity for failure due to imposed stresses, deadleg corrosion, fatigue, etc. Each branch has a complexity factor of 3.

### 8.3.3.1.6 Number of Valves

In an RBI analysis, valves are considered part of the piping. For consistency of analysis, all valves immediately downstream of the piping segment should be considered a part of that segment. Each block valve, control valve, drain valve, and vent valve should be included. Only relief valves are not included in the count.

Small to medium sized leaks at valve packings are not uncommon. Each valve adds a complexity factor of 5.

The complexity factor for a piping segment is the sum of the four values above:

$$\text{Complexity Factor} = (\text{Connections} \times 10) + (\text{Injection Points} \times 20) + (\text{Branches} \times 3) + (\text{Valves} \times 5)$$

Since the generic failure frequency is expressed in units per foot of pipe length, the complexity factor must also be adjusted for pipe length. The complexity factor determined above is divided by pipe length to determine the complexity factor per foot. Numeric values can then be assigned for each pipe segment, as shown in Table 8-17.

### 8.3.3.2 Construction Code

Codes represent the accumulated knowledge from generations of experience in the Process Industry. While designing and fabricating an equipment item according to Code cannot

Table 8-17—Complexity Factors

| Complexity Factor/Ft. | Numeric Value | Complexity Factor/Ft. | Numeric Value |
|-----------------------|---------------|-----------------------|---------------|
| < 0.10                | -3.0          | 2.0 to 3.49           | 1.0           |
| 0.10 to 0.49          | -2.0          | 3.50 to 5.99          | 2.0           |
| 0.50 to 0.99          | -1.0          | 6.00 to 10.00         | 3.0           |
| 1.00 to 1.99          | 0             | > 10.0                | 4.0           |

Table 8-18—Code Status Values

| Status of Code                                                                                                              | Category | Numeric Value |
|-----------------------------------------------------------------------------------------------------------------------------|----------|---------------|
| The equipment meets the latest edition of the Code.                                                                         | A        | 0             |
| The Code for this type of equipment has been significantly modified since the time of fabrication.                          | B        | 1.0           |
| No formal Code existed for this type of equipment at the time of fabrication, or it was not fabricated to an existing Code. | C        | 5.0           |

assure failure-free operation, it provides a proven and accepted basis for minimizing problems in most applications.

Codes are not always available, of course, particularly for specialty equipment and for applications in emerging technologies. Equipment designed and built for these end-uses can operate as safely as more conventional Code equipment, but often reliability and predictability suffer until a greater body of knowledge is established to improve basic designs. In addition, since there are fewer established guidelines, variability between fabricators would be likely to increase.

The following Categories differentiate between equipment items designed and built according to current Codes, obsolete Codes, or where no Codes exist. If a Code vessel has been modified, the modification must also meet Code, or it should be considered a non-Code vessel. Numeric values for each Category are shown in Table 8-18.

In certain cases, it may be appropriate to use a different numeric value for Category "C." If significant industry experience has demonstrated very good (or very poor) service for a particular type of equipment, the numeric value can be adjusted accordingly. In no case, however, should it be less than 2.0. Values above 10.0 would indicate a very severe problem.

### 8.3.3.3 Life Cycle of Equipment

Frequently, the reliability of an equipment item is lower, and its probability of failure is higher, during the item's first few months or years of service. After the resolution of any initial design problems, fabrication defects, operating difficulties, etc., the item's failure frequency remains relatively constant until near the end of its useful life, when the failure frequency often increases again.

This evaluation is based on the design life of the equipment item and on the number of years that the item has been in its current service. The years of service can be different from the age of the plant: less if the item has been replaced or added, or more if the item was previously used in another service.

The design life of equipment is a function of its service in the process. Equipment items that are subject to aggressive damage mechanisms, such as severe corrosion or fatigue problems, will often be designed for a finite life. The probability of failure for such items increases as they near the end of that period. Equipment operating in a more benign environment may well not have a stated or implied design life. Even for these items, however, some increased failure frequency can be expected after an extended period. That period is set at 40 years in the RBI procedure.

Design life, as used in this context, is not equivalent to economic life. Some processes are expected to have a relatively short economic life at the time of their design, and this can influence certain design considerations. However, unless there are known damage mechanisms that will limit the item's life, equipment in such facilities should be assumed to have a 40 year design life.

For the Life Cycle Element, both "Years in Service" and "Design Life" will need to be determined for each equipment item. The numeric values for the Life Cycle correction are based on the percent of the design life that has elapsed since the item entered its current service (Table 8-19).

### 8.3.3.4 Safety Factors

The safety factor is composed of two subelements:

- Operating pressure.
- Operating temperature.



Table 8-19—Life Cycle Values

| % of Design Life Elapsed | Numeric Value |
|--------------------------|---------------|
| 0 to 7                   | 2.0           |
| 7 to 75                  | 0             |
| 76 to 100                | 1.0           |
| > 100                    | 4.0           |

#### 8.3.3.4.1 Operating Pressure

The ratio of operating pressure to design pressure measures the safety factor at normal operating conditions. Equipment operating well below design pressure should have a lower probability of failure than an item operating at full design pressure. The values in Table 8-20 reflect this philosophy.

#### 8.3.3.4.2 Operating Temperature

When equipment items operate at temperatures well above normal practice and near the upper limits for their material of construction, the failure frequency increases.

Similarly, failure frequency is higher for items that operate at abnormally low temperatures. Stresses are created as the equipment is cooled well below ambient temperatures, causing leaks to occur at flanges, etc. This operating temperature factor does not account for brittle fracture of carbon or low alloy steels as a result of low temperature operation. The potential for brittle fracture should be assessed as part of a Technical Module evaluation.

The values in Table 8-21 reflect these concerns.

For operating temperatures between these upper and lower limits, the numeric value of the operating temperature element is 0.

#### 8.3.3.5 Vibration Monitoring Element

Wear is the most common cause of failure of rotating equipment such as pumps and compressors. Wear-related damage can result in seal failure, shaft damage, or in extreme cases, even rupture of the pump case. Vibration monitoring can normally detect developing problems before equipment failure occurs. The values in Table 8-22 should be applied to all pumps and compressors in the study.

For facilities where the risk contributed by erosion or wear in the pressure-containing parts of rotating equipment is a major concern, the RBI analyst can use the Technical Module for thinning mechanisms in Appendix V. That module might provide higher modification factors, based on material handled, service conditions, specific monitoring techniques, etc.

The mechanical subfactor is calculated by adding the factors from each of the five elements in this section.

Table 8-20—Operating Pressure Values

| $P_{oper}/P_{design}$ | Numeric Value |
|-----------------------|---------------|
| > 1.0                 | 5.0           |
| 0.9 to 1.0            | 1.0           |
| 0.7 to 0.89           | 0             |
| 0.5 to 0.69           | -1.0          |
| < 0.5                 | -2.0          |

Table 8-21—Operating Temperature Values

| $T_{operation}$                      | Numeric Value |
|--------------------------------------|---------------|
| For carbon steel: > 550°F            | 2.0           |
| For 1% to 5% chrome steels: > 650°F  | 2.0           |
| For >5% to 9% chrome steels: > 750°F | 2.0           |
| For 304/316 stainless: > 1500°F      | 2.0           |
| For all steels: < -20°F              | 1.0           |

Table 8-22—Values for Vibration Monitoring of Pumps and Compressors

| Monitoring Technique            | Numeric Values |             |
|---------------------------------|----------------|-------------|
|                                 | Pumps          | Compressors |
| No vibration monitoring program | 0.5            | 1.0         |
| Periodic vibration monitoring   | -2.0           | 0           |
| On-line vibration monitoring    | -4.0           | -2.0        |

#### 8.3.4 Process Subfactor

Conditions that are most influenced by the process and how the facility is operated are included in the process subfactor. Information for analyzing these conditions is gathered from operating records, discussions with operating personnel, etc. The resulting numeric values can be universal or item-specific, depending upon the circumstance. This subfactor has the following three elements, each of which has several sub-elements:

- Continuity of the process.
- Stability of the process.
- Relief valves.

Many studies have shown a disproportionate share of equipment failures during periods of nonroutine operation, e.g., startups, shutdowns, and upsets. M & M Protection Consultants put the value at 25% for the large losses they report. This element adjusts the generic failure frequencies for differences in process continuity and basic stability.

For many facilities, the continuity and stability values will be a constant for all equipment items. However, when differ-

ent sections of a unit can be operated independently or have inherently different stability characteristics, specific values should be developed for each section. In a few cases, individual pieces of equipment may require higher or lower values than the remainder of the facility; an exothermic reactor vessel would be one example.

### 8.3.4.1 Continuity of the Process

#### 8.3.4.1.1 Planned Shutdowns

Planned shutdowns include all outages for which the Standard Operating Procedures for shutdown are employed. The exact amount of notice required to qualify as "planned" will vary with the complexity of the process. The intent is to include only those outages where normal, systematic shutdown procedures are employed. The average number of planned shutdowns per year over the last three years should be used to determine the numeric value, unless that period was atypical.

Any shutdown, even one that is carefully planned and conducted, may have the potential for operational errors and mechanical failures. The greater the number of shutdowns, the higher the probability of such failure. The increase in probability is normally not directly proportional to the number of planned outages, however. It can be assumed that batch operations and other operations with frequent planned shutdowns will have been designed to minimize the impact of such outages. This assumption is incorporated in the values of Table 8-23.

#### 8.3.4.1.2 Unplanned Shutdowns

Unplanned shutdowns are those that occur with a minimum of prior planning and include situations such as power failures, leaks, and fires. With even the best of emergency procedures, unplanned shutdowns tend to be more hazardous than planned ones. The numeric values assigned below reflect this (Table 8-24).

Again, the average number of unplanned shutdowns per year over the last three years should be used.

### 8.3.4.2 Stability of the Process

Some processes operate smoothly, day after day, with little intervention from the operators. Others require frequent attention to adjust set points, control product quality, or change product grades. Over time, process instability will result in significant upsets or unplanned outages, thereby increasing failure frequency.

The numeric value assigned for this element is based on the inherent stability of the process. To gain insight on process stability, the RBI users should interview process, engineering, and maintenance personnel, then review available operating records and other source documents. The stability

Table 8-23—Numeric Values for Planned Shutdowns

|               | Number of Planned Shutdowns<br>Numeric Value |
|---------------|----------------------------------------------|
| 0 to 1/year   | -1.0                                         |
| 1.1 to 3/year | 0                                            |
| 3.1 to 6/year | 1.0                                          |
| > 6/year      | 1.5                                          |

Table 8-24—Numeric Values for Unplanned Shutdowns

| Number of Unplanned Shutdowns | Numeric Value |
|-------------------------------|---------------|
| 0 to 1/year                   | -1.5          |
| 1.1 to 3/year                 | 0             |
| 3.1 to 6/year                 | 2.0           |
| > 6/year                      | 3.0           |

ranking will be based on the professional judgment of the observer.

Factors to be considered in making this judgment include:

- Is the chemical process particularly complex? Does the process include any exothermic reactions or abnormally severe temperatures or pressures?
- Has the process been involved in any major incidents at this or any other site?
- Does the process include any unproven process technology or design concepts, or does it require special materials of construction for piping or equipment?
- Does the control system meet current standards, including computer control with appropriate safety features? Is an emergency shutdown system and auxiliary power for control systems needed and/or provided?
- Do the process operators and shift supervisors have extensive training and experience in the process?

In many cases, all equipment items in a plant will be given the same ranking. However, if one section of the plant is significantly more or less stable than another section, and stability in that section does not significantly influence the remainder of the plant, then equipment items in that section should be rated differently than the rest of the plant.

The assigned stability ranking is converted to a numeric value as shown in Table 8-25.

Table 8-25—Numeric Values for Stability Rankings

| Stability Ranking                         | Numeric Value |
|-------------------------------------------|---------------|
| More stable than the average process      | -1.0          |
| Process has about average stability       | 0             |
| Less stable than the average process      | 1.0           |
| Much less stable than the average process | 2.0           |

### 8.3.4.3 Relief Valves Element

The following four subelements deal with pressure relief valves throughout the plant:

- a. Maintenance program.
- b. Fouling service.
- c. Corrosive service.
- d. Very clean service.

The RBI procedure does not address the sizing or location of specific relief valves. It is assumed that those requirements were handled properly during initial plant design or as part of a detailed process hazard analysis. Instead, these questions assess design and process conditions that influence whether the relief valves will be able to function when needed. Obviously, relief valves are most likely to function according to design when they are in clean service and inspected and maintained properly. Deviations from these conditions increase the probability of failure.

In many cases, the conditions affecting relief valves are more nearly universal (plant-wide) than equipment-item specific. One relief valve often protects two or more vessels and all attendant piping. On the other hand, some sections of the plant may present more problems for the relief system than others. The specific situation should dictate whether the questions are answered universally or on an item-specific basis.

#### 8.3.4.3.1 Relief Valve Maintenance Program

Relief valves must be removed from service periodically in accordance with API 510 for maintenance and inspection to ensure that they will function properly. It is, however, beyond the scope of the RBI procedure to analyze the appropriateness of the facility's RV maintenance program. Instead, the numeric value for this subelement is based on the plant's level of compliance with its RV maintenance program.

Plant records should be consulted to determine the percent of relief valves that are overdue for scheduled maintenance and inspection. The percentage should be based on the number of valves overdue, compared to the total population of relief valves. If a definitive schedule has not been established for relief valve maintenance, or if the plant does not maintain a record of overdue valves, the default value, to be applied to all equipment items, is Category D.

If a facility has elected to install block valves under some or all relief valves to permit them to be removed from service during plant operation, it must have a well defined and rigidly enforced procedure to ensure that such block valves cannot be inadvertently closed when the relief valve is in service. This procedure should include a requirement to seal or lock all block valves under active relief valves in an open position. If the facility has block valves under relief valves and does not have a written procedure to this effect, all equipment items in the unit should be rated as Category D. (It is assumed that an

RV would only be removed from service when a redundant valve is in place.)

During the plant walk through, the observer should examine several blocks under relief valves to determine whether they could be closed inadvertently. If any block valves are observed that are not sealed open or otherwise prevented from being closed, all items should be rated as Category D.

Numeric values should be assigned as shown in Table 8-26, including the possible penalties noted above.

#### 8.3.4.3.2 Fouling Service

Equipment items in process streams that contain significant amounts of polymer or other extremely viscous material are more difficult to protect than equipment in clean streams. Even with proper system design, these materials can build up in and around the relief device and inlet piping, blocking or restricting access to the relief valve.

A numeric value is assigned to indicate whether the relief valve is subject to fouling by components in the process stream (Table 8-27). If the fouling tendency varies throughout the plant, it may be necessary to treat this question as item or section specific.

#### 8.3.4.3.3 Corrosive Service

Corrosive process streams present special problems for relief systems. The process side of the system will undoubtedly be designed to withstand the corrosive stream, but often the internals of the relief valve are less resistant. Small leaks past valve seats can corrode valve springs, guides, etc., resulting in unpredictable relief valve performance.

If the process stream is considered corrosive for carbon and low alloy steel, a penalty (as shown in Table 8-28) is assigned unless it is known that all relief valve internals are at least as corrosion-resistant as the process side of the valves, or unless corrosion-resistant rupture discs have been installed under the relief valves.

#### 8.3.4.3.4 Very Clean Service

Relief valves on process streams that have no identifiable fouling tendencies, corrosives, or other contaminants should be more reliable than the average of all relief valves. A credit is given if the process stream meets these requirements as shown in Table 8-29.

### 8.3.5 Summary—Equipment Modification Factor

The preceding sections have developed the Equipment Modification Factor, which is comprised of four subfactors: Technical Module, Universal, Mechanical, and Process. In turn, each subfactor is composed of several elements which have been covered above.

Table 8-26—Numeric Values for Relief Valve Maintenance

| Status of RV Maintenance                                                     | Category | Numeric Value |
|------------------------------------------------------------------------------|----------|---------------|
| Less than 5% of RVs overdue                                                  | A        | -1.0          |
| 5% to 15% of RVs overdue                                                     | B        | 0             |
| 15% to 25% of RVs overdue                                                    | C        | 1.0           |
| Over 25% of RVs overdue, or deficient RV maintenance or block valve program. | D        | 2.0           |

Table 8-27—Numeric Values for Relief Valve Fouling Tendencies

| Fouling Tendency                                                                                               | Category | Numeric Value |
|----------------------------------------------------------------------------------------------------------------|----------|---------------|
| No significant amount of fouling.                                                                              | A        | 0             |
| Some polymer or other fouling material, with a history of occasional buildup in portions of the system.        | B        | 2.0           |
| High level of fouling, with a history of frequent buildup of deposits in RVs and/or other parts of the system. | C        | 4.0           |

Table 8-28—Numeric Value for Corrosion Service

| Corrosive Service<br>(without corrosion-resistant<br>design) | Numeric Value |
|--------------------------------------------------------------|---------------|
| Yes                                                          | 3.0           |
| No                                                           | 0.0           |

Table 8-29—Numeric Values for Very Clean Service

| Very Clean Service | Numeric Value |
|--------------------|---------------|
| Yes                | -1.0          |
| No                 | 0             |

## 8.4 MANAGEMENT SYSTEMS EVALUATION FACTOR

The importance of an effective management system evaluation has long been recognized in preventing releases of hazardous materials and maintaining the mechanical integrity of process equipment. API's Recommended Practice 750, *Management of Process Hazards*, CMA's Responsible Care® series, and various publications by the Center for Chemical Process Safety are a few of the definitive documents that have been issued on the subject. Compliance with PSM standards became mandatory in 1992 with the issue of OSHA's 29 CFR 1910.119, "Process Safety Management of Highly Hazardous Chemicals."

The RBI procedure uses the management systems evaluation factor to adjust generic failure frequencies for differences in process safety management systems. This factor is derived from the results of an evaluation of a facility or operating unit's management systems that affect plant risk. Different practices within units at a facility might create differences in the management systems evaluation factors between the

units. However, within any one study, the management systems evaluation factor should be the same. The factor is applied equally to all equipment items within the study and, as a result, it does not change the order of the risk-based ranking of the equipment items. The management systems evaluation factor can, however, have a pronounced effect on the total level of risk calculated for each item and for the summed risk for the study. This becomes important when risk levels of entire units are compared, or when risk values for similar equipment items are compared between different units or plant sites.

### 8.4.1 Management Systems Evaluation

The management systems evaluation developed for the RBI procedure covers all areas of a plant's PSM system that impact directly or indirectly on the mechanical integrity of process equipment. The management systems evaluation is based in large part on the requirements contained in API Recommended Practices and Inspection Codes. It also includes other proven techniques in effective safety management.

A listing of the subjects covered in the management systems evaluation and the weight given to each subject is presented in Table 8-25. Note that the subject areas cover each of the major paragraphs in API RP 750 (plus a section on Leadership and Administration and a section on Contractors). It is not the intent of the management systems evaluation to measure overall compliance with all API recommendations or OSHA requirements, however. The emphasis is on mechanical integrity issues. Mechanical integrity is the largest single section, and most of the questions in the other subject areas are either closely related to mechanical integrity, or they have a bearing on total unit risk.

The management systems evaluation is attached as a Workbook to this report (Appendix III). It consists of 101 questions, most of which have multiple parts. Most of the questions are structured so that they can have only one

answer: yes or no; a, b, or c; percent completed, etc. Each possible answer to each question is given a weight, depending upon the appropriateness of the answer and the importance of the topic. This system provides a quantitative, reproducible score for the management systems evaluation. It also simplifies analysis of results, permitting the auditor to pinpoint areas of strength and weakness in the facility's PSM system. The number of questions in the management systems evaluation and the breadth of subject matter permits the management systems evaluation to differentiate between PSM systems of different effectiveness.

There is no specific score that indicates compliance vs. noncompliance. Table 8-30 shows this evaluation of the quality of the management systems that impact mechanical integrity. A score of 1000 equates to achieving excellence in PSM issues that affect mechanical integrity. Many of the measured issues may be well beyond what is required for compliance with regulations.

#### 8.4.2 Auditing Technique

The management systems evaluation covers a wide range of topics and, as a result, requires input from several different disciplines within the facility to answer all questions. Ideally, representatives from the following plant functions should be interviewed:

- a. Plant Management.
- b. Operations.
- c. Maintenance.
- d. Safety.
- e. Inspection.
- f. Training.
- g. Engineering.

The number of separate interviews required to complete the management systems evaluation will vary from application to application. In many cases, one individual can effectively answer the questions concerning two or more of the above functions. Normally, however, at least four interviews are required.

The number of auditors involved is arbitrary, but there is some advantage in using more than one. With two or more auditors, the management systems evaluation team can compare notes and often avoid overlooking or misinterpreting important information.

The persons to be interviewed should be designated, and then a subset of questions should be selected from the total management systems evaluation, to match the expertise of each person being interviewed. All audit questions should be answered by someone, of course, but there should be no hesitation to include some of the audit questions in more than one interview. This is sometimes important to provide continuity and clarity during the interview. In addition, it can be revealing to compare answers from different disciplines. Both par-

ties probably answered the questions honestly and candidly, but perceptions can differ markedly.

The intent of the management systems evaluation is to arrive at the single best answer for each question. In addition to comparing answers from different interviews, many of the responses should be verified by physical review of the appropriate written procedures, files and records. The auditor must ensure that the facts substantiate the answer, and that the intent of the question is met before credit is awarded for the answer.

#### 8.4.3 Converting Management Systems Evaluation Score To Management Systems Evaluation Factor

As a minimum, two pieces of information are needed to develop a conversion factor from the management systems evaluation score to a management systems evaluation factor: (1) what score would the "average" plant achieve on the management systems evaluation? (2) how much would the total unit risk be reduced if a plant with the average PSM system were to install a "perfect" PSM system?

Unfortunately, quantitative values are not available for either item. It is possible, however, to make some reasonable assumptions for both.

A review of the questions in the management systems evaluation by an organization with extensive knowledge of the industry estimates that the "average" U.S. petrochemical plant would score about 50%.

The amount of reduction in total unit risk that can be achieved by improvements in a company's PSM system is also difficult to quantify. It can be shown, however, that some companies have lost-time injury rates at least 1 order of magnitude lower than the average rate for all companies. It is logical to assume that a major portion of the improved performance is due to the PSM systems in place at those companies. It is also logical to assume that even the company with the lowest injury rate does not have a "perfect" PSM system and would not score 100% on the management systems evaluation.

The scale recommended for converting a management systems evaluation score to a management systems evaluation factor is based on the assumption that the "average" plant would score 50% on the management systems evaluation, and that a 100% score would equate to a 1 order-of-magnitude reduction in total unit risk. These values are plotted on a semi-log chart in Figure 8-5. This graph provides a management systems evaluation factor for any management systems evaluation score.

The above assumptions can be modified and improved over time as more data become available on management systems evaluation results.

It should be remembered that the management systems evaluation factor applies equally to all equipment items and, therefore, does not change the risk ranking of items for inspection prioritization. The factor's value is in comparing one operating unit or plant site to another.

Table 8-30—Management Systems Evaluation

| Section | Title                         | Questions | Points |
|---------|-------------------------------|-----------|--------|
| 1       | Leadership and Administration | 6         | 70     |
| 2       | Process Safety Information    | 10        | 80     |
| 3       | Process Hazard Analysis       | 9         | 100    |
| 4       | Management of Change          | 6         | 80     |
| 5       | Operating Procedures          | 7         | 80     |
| 6       | Safe Work Practices           | 7         | 85     |
| 7       | Training                      | 8         | 100    |
| 8       | Mechanical Integrity          | 20        | 120    |
| 9       | Pre-Startup Safety Review     | 5         | 60     |
| 10      | Emergency Response            | 6         | 65     |
| 11      | Incident Investigation        | 9         | 75     |
| 12      | Contractors                   | 5         | 45     |
| 13      | Audits                        | 4         | 40     |
| TOTAL   |                               | 101       | 1000   |

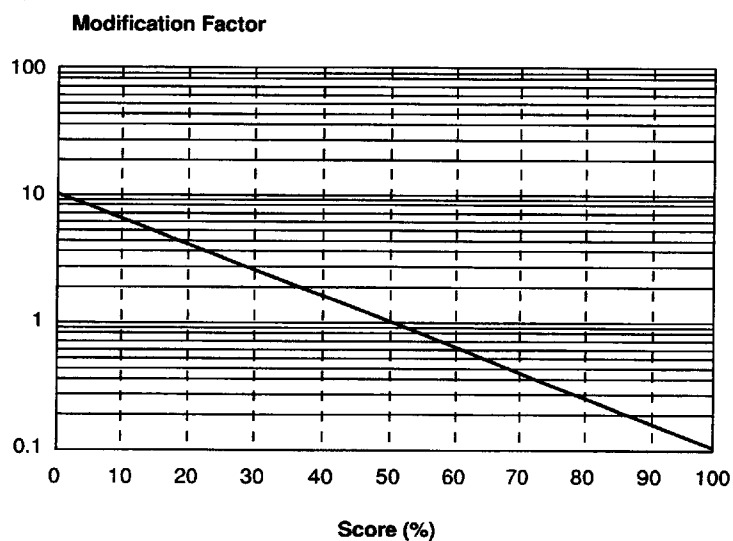


Figure 8-5—Management Systems Evaluation Score vs. PSM Modification Factor

## Section 9—Development of Inspection Programs to Reduce Risk

### 9.1 INTRODUCTION

This section contains two major subsections:

- a. Development of Inspection Programs that address the types of damage that inspection should detect, and the appropriate inspection techniques to detect the damage.
- b. Reducing Risk Through Inspection discusses the application of Risk-Based Inspection tools to reduce risk and optimize inspection programs.

Inspection influences risk primarily by reducing the probability of failure. Many conditions (design errors, fabrication flaws, malfunction of control devices) can lead to equipment failure, but in-service inspection is primarily concerned with the detection of progressive damage. The probability of failure due to such damage is a function of four factors:

- a. Damage mechanism and resulting type of damage (cracking, thinning, etc.).
- b. Rate of damage progression.
- c. Probability of detecting damage and predicting future damage states with inspection technique(s).
- d. Tolerance of the equipment to the type of damage.

Quantitative Risk-Based Inspection considers all of these factors. It differs from conventional inspection management by providing the concepts and methods to support decision-making even when data is missing or uncertain. Rational decisions can be made using the quantitative methods presented in Sections 6 through 8. This section discusses the application of such decision-making methods and applies them to risk reduction in an inspection program. The concepts and methods are further developed in the Worked Examples report that complements this document as Appendix VI.

### 9.2 DEVELOPMENT OF INSPECTION PROGRAMS

The purpose of an inspection program is to define and perform those activities necessary to detect in-service deterioration of equipment before failures occur. An inspection program is developed by systematically identifying:

- a. What type of damage to look for.
- b. Where to look for it.
- c. How to look for the damage (what inspection technique).
- d. When (or how often) to look.

Certain data must be available for the user to begin the steps outlined above. These data include information on the equipment design and construction, the process conditions to which the equipment is exposed, and the equipment history. The following basic data are sufficient to identify most damage mechanisms:

Design and construction data:

- a. Equipment type (heat, mass, or momentum transfer) and function (shell and tube exchanger, trayed distillation column, centrifugal pump, etc.).
- b. Material of construction.
- c. Heat treatment.
- d. Thickness.

Process data, including changes:

- a. Temperature.
- b. Pressure.
- c. Chemical service, including trace components (such as chlorides, CNs, ammonium salts, etc.).
- d. Flow rate.

Equipment history:

- a. Previous inspection data.
- b. Failure analysis.
- c. Maintenance activity.
- d. Replacement information.
- e. Modifications.

#### 9.2.1 What Type of Damage To Look For and Where To Look

Damage types are the physical characteristics of damage that can be detected by an inspection technique. Damage mechanisms are the corrosion or mechanical actions that produce the damage. Table 9-1 describes damage types and their characteristics. Tables 9-2 through 9-6 list damage mechanisms by broad categories. The types of damage that can be associated with them are also listed. These lists of damage mechanisms were developed by several API members of the Fitness for Service Program.

Damage may occur uniformly throughout a piece of equipment, or it may occur locally, depending on the mechanism at work. Uniformly occurring damage can be inspected and evaluated at any convenient location, since the results can be expected to be representative of the overall condition. Damage that occurs locally requires a more focused inspection effort. This may involve inspection of a larger area to ensure that localized damage is detected. If the damage mechanism is sufficiently well understood to allow prediction of the locations where damage will occur, the inspection effort can focus on those areas.

#### 9.2.2 How To Look For Damage (Inspection Technique)

Inspection techniques are selected based on their ability to find the damage type; however, the mechanism that caused the damage can affect the inspection technique selection.

Table 9-1—Damage Types and Characteristics

| Damage Type                                        | Description                                                               |
|----------------------------------------------------|---------------------------------------------------------------------------|
| Thinning (includes general, localized and pitting) | Removal of material from one or more surfaces may be general or localized |
| Surface connected cracking                         | Cracking that is connected to one or more metal surfaces                  |
| Subsurface cracking                                | Cracking beneath the metal surface                                        |
| Microfissuring/microvoid formation                 | Microscopic fissures or voids beneath the metal surface                   |
| Metallurgical changes                              | Changes to the metal microstructure                                       |
| Dimensional changes                                | Changes in the physical dimensions or orientation of an object            |
| Blistering                                         | Hydrogen-induced blisters forming in plate inclusions                     |
| Material properties changes                        | Changes in the material properties of the metal                           |

Table 9-2—Corrosion Damage Mechanisms

| Damage Mechanism                             |
|----------------------------------------------|
| HCl corrosion                                |
| Organic chlorides corrosion                  |
| Inorganic chlorides corrosion                |
| Organic sulfur corrosion                     |
| H <sub>2</sub> /H <sub>2</sub> S Sulfidation |
| CO <sub>2</sub> corrosion                    |
| Naphthenic acid corrosion                    |
| Sour water corrosion                         |
| Sulfuric acid corrosion                      |
| Hydrofluoric acid corrosion                  |
| Phenol/NMP corrosion                         |
| Phosphoric acid corrosion                    |
| Caustic corrosion                            |
| Ammonia corrosion                            |
| Chlorine/sodium hypochlorite corrosion       |
| Corrosion under insulation/fireproofing      |
| Cooling water corrosion                      |
| Atmospheric corrosion                        |
| Soil corrosion                               |
| High temperature oxidation                   |
| Hot corrosion                                |
| Flue gas corrosion                           |
| Dealloying                                   |
| Galvanic corrosion                           |
| Crevice/underdeposit corrosion               |
| Biological corrosion                         |
| Injection point corrosion                    |
| Boiler water/condensate corrosion            |
| Flue gas dewpoint corrosion                  |

Note: All of the following damage mechanisms relate to thinning of metals by corrosion. The damage type for all of these mechanisms is thinning.

Table 9-3—Stress Corrosion Cracking Damage Mechanisms

| Damage Mechanism           |
|----------------------------|
| Amine                      |
| Ammonia                    |
| Caustic                    |
| Carbonate                  |
| Chloride                   |
| Polythionic acid           |
| Liquid metal embrittlement |
| Hydrofluoric acid          |
| Corrosion fatigue          |

Note: All of the following damage mechanisms relate to surface connected cracking of metals.



The following damage mechanisms may produce more than one type of damage. The applicable damage types are listed.

Table 9-4—Hydrogen Induced Damage Mechanisms

| Damage Mechanism                                        | Damage Types                                                                        |
|---------------------------------------------------------|-------------------------------------------------------------------------------------|
| Blistering                                              | Blistering, subsurface cracking, surface connected cracking, dimensional changes    |
| Hydrogen induced cracking, including step-wise cracking | Subsurface cracking, surface connected cracking                                     |
| Stress oriented hydrogen induced cracking (SOHIC)       | Microfissuring/microvoid formation, subsurface cracking, surface connected cracking |
| Sulfide stress cracking                                 | Surface connected cracking                                                          |
| Cyanide stress cracking (HCN)                           | Surface connected cracking                                                          |
| Hydriding                                               | Subsurface cracking, surface connected cracking, metallurgical changes              |
| Hydrogen attack                                         | Microfissuring/microvoid formation, metallurgical changes, cracking                 |
| Hydrogen embrittlement                                  | Surface connected cracking, material property changes                               |

Table 9-5—Mechanical Damage Mechanisms

| Damage Mechanism            | Damage Types                                                                                                                    |
|-----------------------------|---------------------------------------------------------------------------------------------------------------------------------|
| Erosion—solids              | Thinning                                                                                                                        |
| Erosion—droplets            | Thinning                                                                                                                        |
| Cavitation                  | Thinning                                                                                                                        |
| Sliding wear                | Thinning                                                                                                                        |
| Fatigue                     | Surface connected cracking, subsurface cracking                                                                                 |
| Thermal fatigue             | Surface connected cracking                                                                                                      |
| Corrosion fatigue           | Surface connected cracking                                                                                                      |
| Creep and stress rupture    | Microfissuring/microvoid formation, subsurface cracking, surface connected cracking, metallurgical changes, dimensional changes |
| Creep cracking              | Microfissuring/microvoid formation, subsurface cracking, surface connected cracking                                             |
| Thermal ratcheting          | Surface connected cracking, dimensional changes                                                                                 |
| Overload (plastic collapse) | Dimensional changes, thinning                                                                                                   |
| Brittle fracture            | Metallurgical changes, material property changes                                                                                |

Table 9-6—Metallurgical and Environmental Damage Mechanisms

| Damage Mechanism                          | Damage Types                                                                                                                     |
|-------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------|
| Incipient melting                         | Microfissuring/microvoid formation, subsurface cracking, surface connected cracking, metallurgical and material property changes |
| Spheroidization and graphitization        | Microfissuring/microvoid formation, subsurface cracking, surface connected cracking, metallurgical and material property changes |
| Hardening                                 | Metallurgical and material property changes                                                                                      |
| Sigma and Chi phase embrittlement         | Metallurgical and material property changes                                                                                      |
| 885 °F embrittlement                      | Metallurgical and material property changes                                                                                      |
| Temper embrittlement                      | Metallurgical and material property changes                                                                                      |
| Reheat cracking                           | Surface connected cracking, metallurgical and material property changes                                                          |
| Carbide precipitate embrittlement         | Metallurgical and material property changes                                                                                      |
| Carburization                             | Metallurgical and material property changes                                                                                      |
| Decarburization                           | Metallurgical and material property changes                                                                                      |
| Metal dusting                             | Thinning                                                                                                                         |
| Nitriding                                 | Metallurgical and material property changes                                                                                      |
| Strain aging                              | Metallurgical and material property changes                                                                                      |
| Softening due to overaging                | Metallurgical and material property changes                                                                                      |
| Brittleness due to high temperature aging | Metallurgical and material property changes                                                                                      |

Table 9-7 qualitatively lists the effectiveness of inspection techniques for each damage type listed in Table 9-2. A range of effectiveness is given for some damage type/inspection technique combinations based on comments from various sources, including the API Subcommittee on Inspection. Selection of the inspection technique will depend on not only the effectiveness of the method, but on equipment availability and whether or not an internal inspection can be made.

### 9.2.2.1 Inspection Effectiveness

Table 9-7 gives some guidance for the observed effectiveness of various inspection techniques. Note that for the damage type of microfissuring/microvoid formation, no one inspection technique is considered highly effective. Note also that no inspection technique is always considered to be highly effective for all damage types. For almost all damage types, more than one inspection technique can be used, each enhancing the effectiveness of the other. For example, ultrasonic thickness measurements are much more effective at locating internal corrosion if they are combined with an internal visual inspection. Creep damage with the associated microvoid formation, fissuring and dimensional changes is not effectively found by any one inspection technique. However, when a combination of techniques (ultrasonics, radiography, dimensional measurements and replication) is employed, the results are usually satisfactory.

RBI requires a quantitative estimate of inspection effectiveness for use in the Technical Modules as described in Section 8.3.1. The following subsection shows how the estimate of inspection effectiveness is developed.

### 9.2.2.2 Qualitative Assessment of Inspection Effectiveness

As the analyst progresses from observing the effectiveness of inspection techniques to quantifying the effectiveness of an inspection plan for a piece of equipment, the following five factors must be evaluated:

- Damage density and variability.
- Inspection sample validity.
- Sample size.
- Detection capability of the inspection methods.
- Validity of future predictions based on past observations.

A rigorously quantitative approach would require a probabilistic description of each of the five factors, permitting the inspection effectiveness to be presented as a probabilistic expression. Such an approach is too costly and complicated for the general approach of RBI.

The RBI approach to assessing inspection effectiveness categorizes the ability of inspection types, or common combinations of inspection types, to detect and evaluate in-service damage. An example is the combination of visual and ultrasonic inspections for the detection and measurement of general corrosion. The effectiveness categories are based on evaluating the five factors identified above. In light of these factors, the inspections are categorized according to their ability to detect and quantify the anticipated progressive damage.

The inspection effectiveness categories are:

- Highly Effective.
- Usually Effective.
- Fairly Effective.
- Poorly Effective.
- Ineffective.

Table 9-7—Effectiveness of Inspection Techniques for Various Damage Types

| Inspection Technique          | Thinning | Surface<br>Connected<br>Cracking | Subsurface<br>Cracking | Microfissuring/<br>Microvoid<br>Formation | Metallurgical<br>Changes | Dimensional<br>Changes | Blistering |
|-------------------------------|----------|----------------------------------|------------------------|-------------------------------------------|--------------------------|------------------------|------------|
| Visual Examination            | 1-3      | 2-3                              | X                      | X                                         | X                        | 1-3                    | 1-3        |
| Ultrasonic Straight Beam      | 1-3      | 3-X                              | 3-X                    | 2-3                                       | X                        | X                      | 1-2        |
| Ultrasonic Shear Wave         | X        | 1-2                              | 1-2                    | 2-3                                       | X                        | X                      | X          |
| Fluorescent Magnetic Particle | X        | 1-2                              | 3-X                    | X                                         | X                        | X                      | X          |
| Dye Penetrant                 | X        | 1-3                              | X                      | X                                         | X                        | X                      | X          |
| Acoustic Emission             | X        | 1-3                              | 1-3                    | 3-X                                       | X                        | X                      | 3-X        |
| Eddy Current                  | 1-2      | 1-2                              | 1-2                    | 3-X                                       | X                        | X                      | X          |
| Flux Leakage                  | 1-2      | X                                | X                      | X                                         | X                        | X                      | X          |
| Radiography                   | 1-3      | 3-X                              | 3-X                    | X                                         | X                        | 1-2                    | X          |
| Dimensional Measurements      | 1-3      | X                                | X                      | X                                         | X                        | 1-2                    | X          |
| Metallography                 | X        | 2-3                              | 2-3                    | 2-3                                       | 1-2                      | X                      | X          |

1 = Highly effective

2 = Moderately effective

3 = Possibly effective

X = Not normally used

Since the rigorously quantitative approach is usually not possible with the data available, the RBI evaluation relies heavily on professional judgment and expert opinion. Table 9-8 describes the factors that would be considered in either the RBI or rigorously quantitative approach, and follows the example for the case of general corrosion of a vessel.

The inspection effectiveness is qualitatively evaluated by assigning the inspection methods to one of five descriptive categories listed in Table 9-9. The categories have been increased to five, versus the four in Table 9-7, to provide additional discrimination. Assignment of categories is based on professional judgment and expert opinion. Examples of each category are presented in Table 9-9 for the case of a vessel subject to internal general corrosion.

### 9.2.2.3 Quantifying Inspection Effectiveness

In order to quantitatively express the impact of inspection on the probability of failure, it is necessary to develop a method to convert the above qualitative categories into quantitative measures of inspection effectiveness. The approach used follows the example in the Technical Modules (see 8.3.1). The goal is to express how effective the inspection is at correctly identifying the state of damage in the equipment examined. This is simplified by considering the state of dam-

age as being within one of three categories. The exact definition of the categories differs for each technical module, but a generic description is provided below, repeating the example of general corrosion used in Section 8.

This approach is used to take advantage of Bayes' Theorem (see 8.3.1.4), which can effectively be used to quantitatively process information based on expert opinion. When those opinions are subject to updating, based on tests that may in themselves be inconclusive, Bayes' Theorem can again prove effective. The effectiveness of inspections from the qualitative categories is quantified based on consideration of Bayesian updating techniques.

First consider the "highly effective" qualitative category. Inspection methods that fit this category would fail to identify the damage state in only a few instances. If an equipment item is inspected with this technique, the likelihood of the damage state being "considerably worse" (State 3) than what the inspection results indicate is 1% or less (i.e., with further analysis, only one out of one hundred inspections would reveal that the damage state is "considerably worse"). The qualitative inspection category of "highly effective" is given a quantitative effectiveness value of 0.01 for Damage State 3. Thus, 99% of the time the actual damage state of the equipment is in State 1 or State 2; 90% of the time the actual dam-

Table 9-8—Factors Considered in Assessing Inspection Effectiveness

| Evaluation Factor                                          | Rigorously Quantitative Approach                                                                   | RBI Approach                                                                                                                                                            | Example of RBI Approach for General Corrosion                                                                                                                     |
|------------------------------------------------------------|----------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Damage density and variability.                            | Density, mean and extreme value distributions of damage                                            | 1. Damage occurs over either a large or small area.<br>2. Damage can occur randomly, or locations for damage can be predicted.                                          | General corrosion occurs over a substantial portion of the surface area and is relatively uniform.                                                                |
| Validity of sample                                         | Sample must be representative of the population about which a statistical inference is to be made. | The inspection program is designed to concentrate on areas where damage is likely to occur.                                                                             | For general corrosion, most samples will be representative of the condition; however, the rate of corrosion may vary significantly within one piece of equipment. |
| Sample size                                                | Sample size must be statistically significant.                                                     | The area inspected should be appropriate for damage mechanisms that are highly localized.                                                                               | Visual examination, combined with ultrasonics, increases the significance of the sample vs. spot ultrasonic thickness readings alone.                             |
| Detection capability                                       | Probability of Detection (POD) curves describe the capability of the method.                       | The capability of the inspection type is evaluated qualitatively.                                                                                                       | Refer to Table 9-7. Visual examination is rated "possibly" to "highly" effective; ultrasonic thickness measurements are rated "moderately" to "highly" effective. |
| Validity of future predictions based on past observations. | Damage is modeled showing rate variation with time, etc.                                           | The past observation of damage is used to predict the future, based on increase or decrease in damage rate, or based on changes to process parameters affecting damage. | General corrosion is assumed to occur at the same rate in the future as in the past, unless the process changes (feedstock, temperature, etc.)                    |

Table 9-9—The Five Effectiveness Categories

| Qualitative Inspection Effectiveness Category                                                                                                   | General Corrosion Examples                                                                                              |
|-------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------|
| <b>Highly Effective</b><br>Inspection methods correctly identify the anticipated in-service damage in nearly every case. (90%).                 | Assessment of general corrosion by complete internal visual examination coupled with ultrasonic thickness measurements. |
| <b>Usually Effective</b><br>The inspection methods will correctly identify the actual damage state most of the time. (70%).                     | Assessment of general corrosion by partial internal visual examination coupled with ultrasonic thickness measurements.  |
| <b>Fairly Effective</b><br>The inspection methods will correctly identify the true damage state about half of the time. (50%).                  | Assessment of general corrosion by external spot ultrasonic thickness measurements.                                     |
| <b>Poorly Effective</b><br>The inspection methods will provide little information to correctly identify the true damage state. (40%).           | Assessment of general corrosion by hammer testing, telltale holes.                                                      |
| <b>Ineffective</b><br>The inspection method will provide no or almost no information that will correctly identify the true damage state. (33%). | Assessment of general internal corrosion by external visual examination.                                                |

Table 9-10—Generic Descriptions of Damage State Categories

| Damage State Category                                                                                                                                                                                           | Example—General Corrosion                                                                                                                                               |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Damage State 1</b><br>The damage in the equipment is no worse than what is expected based on damage rate models or experience.                                                                               | The rate of general corrosion is less than or equal to the rate predicted by past inspection records or historical data, if no inspections have been performed. (0–1X). |
| <b>Damage State 2</b><br>The damage in the equipment is “somewhat” worse than anticipated. This level of damage is sometimes seen in similar equipment items.                                                   | The rate of general corrosion is as much as twice the predicted rate. (1X–2X).                                                                                          |
| <b>Damage State 3</b><br>The damage in the equipment is “considerably worse” than anticipated. This level of damage is rarely seen in similar equipment items, but has been observed on occasion industry-wide. | The rate of general corrosion is as much as four times the predicted rate. (2X–4X).                                                                                     |

age state is what was indicated by the inspection technique, and the remaining 9% of the time the damage is “somewhat worse” than what the inspection indicates (State 2).

If the inspection method is considered to be “ineffective,” then by Bayesian updating methods, one damage state is as likely to occur as another, at least based on the results of this inspection method. In this case, the quantitative effectiveness values are 0.33 for each of the damage states. Using this as a guide, if the method is considered to be only slightly better than completely ineffective, then the likelihood of predicting the true rate will be a little higher than 0.33, and the likelihood of four times the rate will be a little lower than 0.33.

These can be adjusted further, based on the expert opinion as above, and consistent with the previous predictions.

Table 9-11 presents the quantitative effectiveness values for each of the above examples, plus the other inspection categories in between: usually effective, fairly effective, and poorly effective.

These values can be used for inspection updating based on the Bayesian techniques outlined in 8.3.1.

### 9.2.3 Probability of Detection

Inspection techniques vary in their accuracy, depending on operator skill and test conditions. Accuracy can be measured

Table 9-11—Quantitative Inspection Effectiveness—Likelihood That Inspection Result Determines the True Damage State

| Damage State Category             | Effectiveness Category |                   |                  |                  |             |
|-----------------------------------|------------------------|-------------------|------------------|------------------|-------------|
|                                   | Highly Effective       | Usually Effective | Fairly Effective | Poorly Effective | Ineffective |
| First damage state: Measured rate | 0.9                    | 0.7               | 0.50             | 0.40             | 0.33        |
| Second damage state: Higher rate  | 0.09                   | 0.2               | 0.30             | 0.33             | 0.33        |
| Third damage state: Higher rate   | 0.01                   | 0.1               | 0.20             | 0.27             | 0.33        |

by repeating the examinations of known flaws of various sizes and recording the results. Actual tests done in this round-robin style reveal a probability of detection for flaws in a test block. The application of these data to in-service plant inspections is somewhat limited since they are based on examination of prepared test blocks in a comfortable laboratory environment. However, they provide two very important pieces of information:

- They establish that there is a probability of detection (POD). Even under controlled conditions, nondestructive testing has limitations and reveals an increased probability of detection for flaws as the size of the flaws increase.
- They establish the basis for the maximum effectiveness that can be expected from an inspection. "Real world" probabilities of detection may approach this effectiveness, but could not be expected to exceed it.

Several organizations have tried to quantify the probability of detection by performing round-robin type tests:

- Nordtest in Europe (Ultrasonics (UT), MPI (MT), & Radiography (RT)).
- PISC (Italy).
- EPRI (USA).
- CIPS in USA (UT-Nuclear applications).
- Nippon Steel Japan (MPI).
- US-Navy (UT and Radiography-Submarines).

An example of a POD curve generated by such tests is shown in Figure 10-1. A three-parameter Weibull distribution has been fitted to the data.

As discussed in the previous section on inspection effectiveness, these POD data can be used in a quantitative assessment of inspection effectiveness through extreme value analysis if sufficiently detailed information on the distribution of damage states is also available.

The POD data, where available, are also useful in helping assign the inspection methods to the appropriate inspection effectiveness category.

### 9.2.4 When (How Often) To Look For Damage

Inspection frequency is determined by combining the four factors of Risk Based Inspection presented in Section 8.1 and in the previous sections:

- Damage mechanism and resulting type of damage (cracking, thinning, etc.).
- Rate of damage progression.
- Tolerance of the equipment to the type of damage.
- Probability of detecting damage and predicting future damage states with inspection technique(s).

The frequency is selected as some fraction of the equipment's remaining life. The remaining life is defined as:

$$\text{Remaining Life (years)} = \frac{\text{Damage Tolerance (units)}}{\text{Damage Rate (units/yr)}}$$

For the simple example of general corrosion in 8.2.3, the familiar equation from API 510 results:

|                        |                                   |
|------------------------|-----------------------------------|
| Vessel:                | Atmospheric Overhead Accumulator. |
| Material:              | SA 285-Gr.C                       |
| Thickness:             | 3/8 in.                           |
| Design Pressure:       | 50 psig                           |
| Corrosion Allowance:   | 3/16 in.                          |
| Diameter:              | 6 ft 6 in.                        |
| Design Corrosion Rate: | 10 mpy                            |
| Age:                   | 6 years                           |
| Prior Inspection Data  | none                              |

A more complex example of progressive damage is illustrated in Figure 9-2. A piece of equipment with some load-bearing function begins life with its strength exceeding the load by some factor of safety. A damage mechanism begins to weaken the equipment progressively. Suppose for this example that the damage in similar pieces of equipment has been observed to progress more rapidly in some cases (the lower dashed line), and less rapidly in other cases (the upper dashed

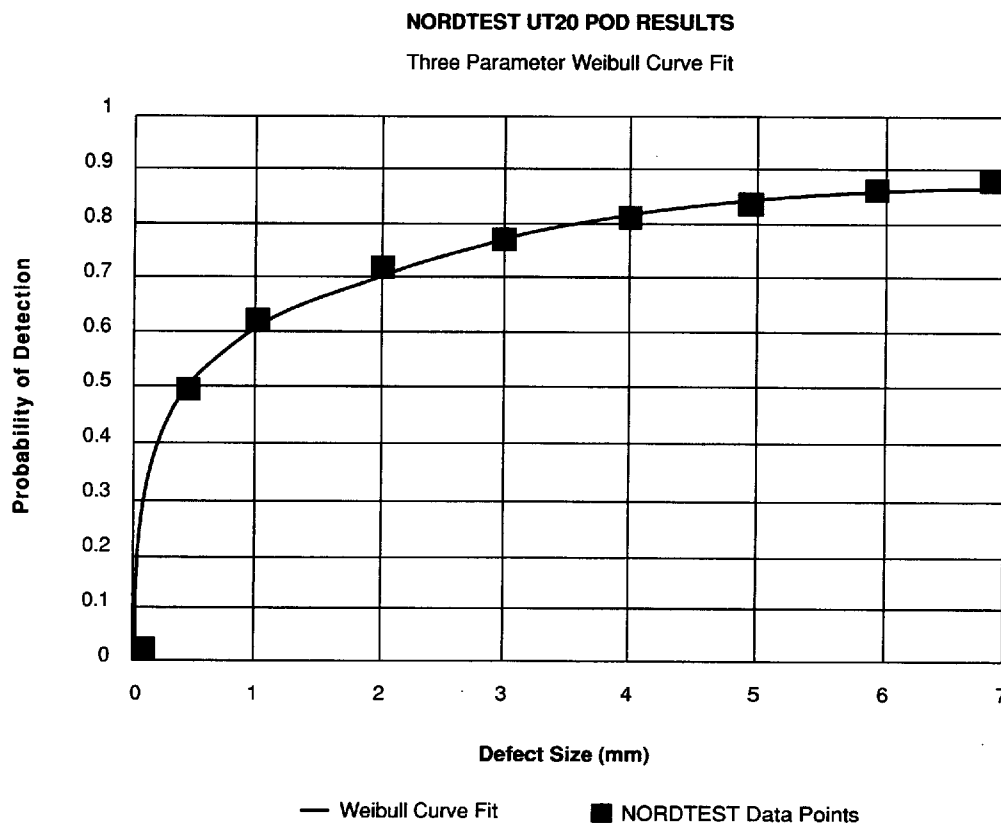


Figure 9-1—POD Curves for Ultrasonic Inspection

line), with some average rate being observed (the solid line between the two dashed lines). Further, there are some fluctuations in the applied load, indicated by the dotted lines.

The first few failures occur where the most rapid damage cases coincide with the highest applied loads. The “average” piece of equipment lasts until the average damage progression results in reduced strength corresponding to the average load. This describes the “average” failure. A few pieces of equipment exhibit low damage growth and also see low applied loads. These few last the longest. Equipment life is seen as an increasing probability of failure over time, by recognizing uncertainties in the damage growth rate, the tolerance of the equipment to damage, and the applied loads. Inspection gives the opportunity to “look at the dealer’s cards,” that is, to determine exactly where a particular piece of equipment stands at some point in time with respect to the damage progression. The “real” probability of failure can then be estimated based on whether the damage is progressing at a high or low rate. Decisions to continue service for a while or replace the equipment can then be made based on this new information.

### 9.3 REDUCING RISK THROUGH INSPECTION

This section builds on the inspection program development guides of the previous section and incorporates the tools from Section 8 to illustrate risk reduction through inspection.

#### 9.3.1 Measuring Risk Associated With Existing Inspection System

In order to evaluate risk reduction via inspection programs, the risk associated with the existing program must be measured. Section 8 quantifies the probability of failure based on the likelihood that different damage states exist, given the level of inspection that has been performed on the equipment. This is used as a starting point to evaluate different programs using different techniques or frequencies. The example from Section 9 is repeated here to illustrate the approach.

In this case study, a “usually effective” inspection was performed after six years. For the following analysis, it is assumed that the inspection revealed an actual corrosion rate of 5 mpy vs. the predicted rate of 10 mpy. Figure 9-3 shows the damage subfactor table from the technical module for

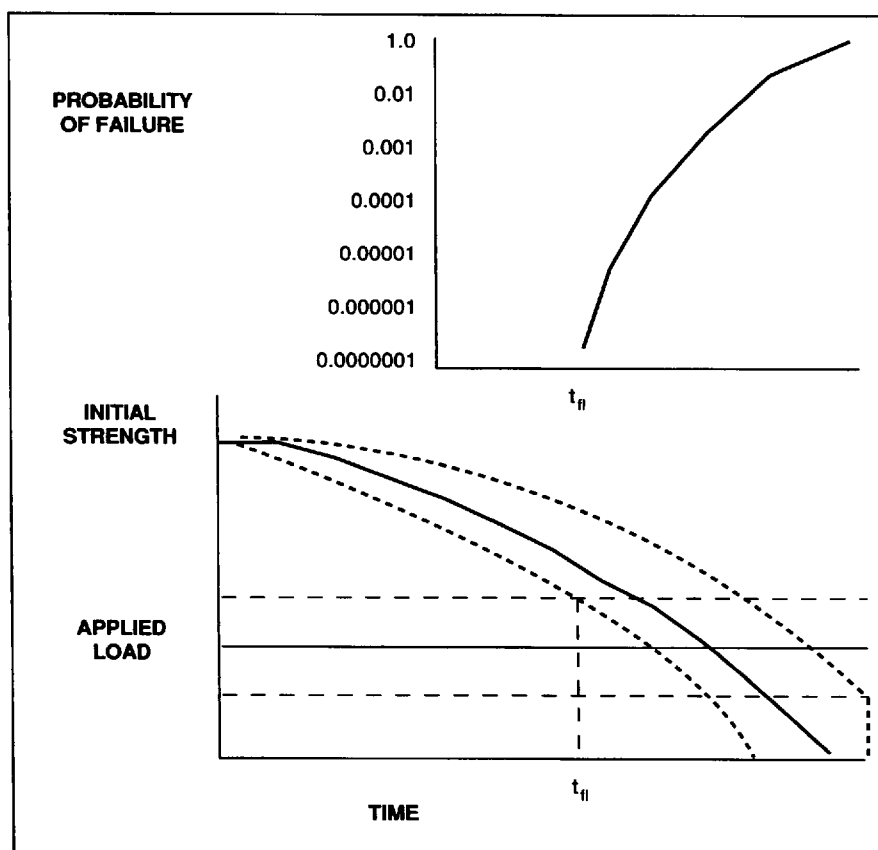


Figure 9-2—Probability of Failure With Time

general corrosion. The thick line on the table shows the “path” traced by an inspection plan (this is discussed further in the next section). Using Table 9-19, the following steps show how the damage subfactor is calculated for the risk assessment.

Step 1: Calculate the ratio  $ar/t$ .

This is the equipment age (or time in current service) ( $a$ ) times the corrosion rate ( $r$ ), in in./yr, divided by the original thickness (or thickness at time equipment went into current service) ( $t$ ).

Example: 5 mpy (0.005 in./yr), 6 years old, original thickness 0.375 in.  $ar/t = 6 \times 0.005/0.375 = 0.08$ .

Step 2: Determine the oversize factor.

This is a correction factor selected from the table in Table 9-12 that will be applied to the damage subfactor. The correction is necessary because the subfactors from the table are based on a vessel that has a corrosion allowance of 25% of the wall thickness, while the vessel in this example has a corrosion allowance of 50% of the wall thickness. Vessels with a greater corrosion allowance should have a lower damage subfactor, while those with less corrosion allowance should have a higher damage subfactor.

Example:

Original thickness = 0.375 in.,

Corrosion allowance = 0.1875.

$$t_{actual} / (t_{actual} - \text{Corrosion Allowance}) = 0.375 / 0.1875 = 2.0.$$

The oversize factor selected from the table, is 0.5; that is, the damage subfactors are to be multiplied by one-half (for subfactors greater than 1).

Step 3: Refer to Figure 9-3 to find the damage subfactor for this vessel. At one inspection (of any effectiveness) and  $ar/t = 0.08$ , the damage subfactor is 1.

Step 4: Multiply results of Step 3 by results of Step 2.

### 9.3.2 Evaluating Alternate Inspection Programs

The following four inspection program options are to be examined:

Plan 1. Continue with “usually effective” inspection conducted every three years. This inspection involves spot thickness readings combined with a partial internal inspection.

Plan 2. Continue “usually effective” inspection but extend the inspection period to six years.





Plan 3. Change to a "highly effective" inspection conducted every six years. This inspection involves an extensive internal inspection with numerous thickness measurements.

Plan 4. Perform only spot ultrasonic thickness measurements ("fairly effective") externally every three years.

These four plans are to be evaluated based on their effect on risk. Since the consequences of failure are the same for all four inspection plans, to evaluate the plans with respect to each other, only the damage subfactor needs to be compared. The risk associated with the plan can be compared to other plans for other vessels, and priorities established based on risk as outlined in the next section.

Evaluate Plan 1 first. As seen in Table 9-12, the damage subfactor at the current time (after the first inspection) is 1. The next step is to determine the damage subfactors for each future point in time associated with the plan. The evaluation of the plan is based on the assumption that future inspection findings do not differ greatly from the last inspection. If changes do occur, the plan will need to be reevaluated in the same manner as outlined here.

Calculate ratio  $ar/t$  for the Plan 1 inspection times. These times are every three years starting at the current vessel age (6 years). The ratio is calculated for 9 years (0.12), 12 years (0.16), 15 years (0.20), and 18 years (0.24). At the next inspection for Plan 1, the vessel will be 9 years old, and it will have had just one inspection prior to the planned inspection. The damage subfactor is found for the case of one inspection (usually effective) and  $ar/t$  of 0.12. This damage subfactor is  $2 \times 0.5$  (overdesign factor) = 1. Now move horizontally across the chart to two usually effective inspections. The damage subfactor is 1. Repeat this process for future inspections. The "path" traced by this inspection plan is shown on Figure 8-5 as a thick line.

The results are:

| Year (vessel age)  | $ar/t$ | # of Inspections | Damage Subfactor |
|--------------------|--------|------------------|------------------|
| 6 (starting point) | 0.08   | 1                | 1                |
| 9                  | 0.12   | 1                | 1                |
| 9                  | 0.12   | 2                | 1                |
| 12                 | 0.16   | 2                | 2                |
| 12                 | 0.16   | 3                | 1                |
| 15                 | 0.20   | 3                | 3                |
| 15                 | 0.20   | 4                | 1                |
| 18                 | 0.24   | 4                | 1                |
| 18                 | 0.24   | 5                | 1                |

As can be seen, the damage subfactor remains close to 1 throughout the inspection period examined. Plans 2, 3, and 4 are evaluated in a similar fashion. Table 9-13 shows the damage factors for the four programs.

Plans 1 and 3 have kept damage factors low throughout the period examined, while neither Plan 2 nor 4 does enough inspections of sufficient effectiveness to rule out a significant probability that the corrosion rate exceeds the observed 5 mpy. The costs of Plans 1 and 3 inspection types do not significantly differ since both involve internal entry. Plan 3 is chosen as the more economical option, since it involves less activity, yet the damage factor, hence the risk level, is not significantly different from that in Plan 1.

### 9.3.3 Optimizing the Inspection Program

The above example of using Risk-Based Inspection tools to evaluate options for an inspection program shows how inspection planning can be optimized by:

- Increasing activity level or frequency if insufficient reduction in risk occurs, or
- Decreasing activity level or frequency if no gain in risk reduction results from the higher level of inspections.

The following are general guidelines that may be used for program optimization:

- Damage factors can usually be kept close to one by inspection activities of a moderate extent. Values exceeding ten can usually be avoided.
- Damage factors significantly greater than ten may be calculated when an inspection program that has not previously been based on risk is first evaluated. Equipment items showing these higher values should receive first priority for inspection optimization. Within this set of equipment items, those with the highest risk should be evaluated first.
- Some equipment that has been inspected multiple times and has confirmed low damage rates may be over-inspected. Alternate plans to reduce inspection activity or frequency can be evaluated through the technical modules to determine the effect on risk. Within this set of equipment items, those with the lowest risk should be evaluated first.
- Equipment that is subject to a large uncertainty in the damage rate (as expressed in the Technical Module) will require frequent or thorough inspections to keep risk levels low, at least until sufficient history on performance has been established.
- Equipment that is approaching the end of its life due to corrosion or other deterioration requires increased inspection activity to be sure that the limits of deterioration (e.g., corrosion allowance) are not exceeded. Increased inspection will not reduce the damage factor once the remaining life has been consumed.
- Inspection program options should be projected over a significant portion, at least half, of the equipment's intended remaining life. Damage factors may tend to increase later in the equipment life if insufficient inspections are performed.

These guidelines are summarized in Table 9-14.

Table 9-13—Damage Factors for Four Inspection Plans

| Year<br>(ar/t) | Damage Factor, Before/after Inspection |        |        |        | Damage Factor Comments                                                                                                                     |
|----------------|----------------------------------------|--------|--------|--------|--------------------------------------------------------------------------------------------------------------------------------------------|
|                | Plan 1                                 | Plan 2 | Plan 3 | Plan 4 |                                                                                                                                            |
| 6<br>(0.08)    | 1                                      | 1      | 1      | 1      | All four plans start out the same.                                                                                                         |
| 9<br>(0.12)    | 1/1                                    |        |        | 1/1    | 1/1 indicates the damage factor was the same before and after inspection. No inspections are done for Plan 2 and Plan 3.                   |
| 12<br>(0.16)   | 2/1                                    | 10/2   | 2/1    | 10/5   | Plan 2 and Plan 4 are starting to show higher damage factors prior to inspection.                                                          |
| 15<br>(0.20)   | 3/1                                    |        |        | 30/10  | Plan 4 has not performed enough inspections. Confidence in the corrosion rate does not outweigh the possibility that a higher rate exists. |
| 18<br>(0.24)   | 1/1                                    | 15/3   | 1/1    | 15/8   | Plan 2 has not performed enough inspections. Confidence in the corrosion rate does not outweigh the possibility that a higher rate exists. |

Table 9-14—Inspection Program Evaluation for Risk Reduction and Optimization

|        |                         |                                                                                                                                                                                                                                     |
|--------|-------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Step 1 | Baseline risk ranking   | Perform risk ranking of current system.                                                                                                                                                                                             |
| Step 2 | Risk reduction          | From the set of highest risk items, select those that also have a high likelihood of failure due to a high damage subfactor. Evaluate optional inspection plans to reduce the risk, and implement the plan selected.                |
| Step 3 | Inspection optimization | From the set of lowest risk items, select those that have a low likelihood of failure due to a low damage factor. Evaluate optional inspection plans to find the optimal amount of inspection effort required to maintain low risk. |

### 9.3.4 Guidelines For Prioritizing Equipment For Positive Materials Identification (PMI)

Risk Based Inspection provides a powerful tool for evaluating various “what-if” scenarios. For example, a plant may want to evaluate scenarios such as:

- What if we increase the process temperature?
- What if we change the refinery feedstock?
- What if the wrong material of construction was inadvertently used in construction or repairs?

In these examples, that last one is of particular interest if quality control of materials used for construction or repairs is suspect. It is very easy to accidentally use wrong materials that look like the right material if extreme caution is not taken in identifying and marking materials as they are received and stored. Typical of such mix-ups of look-alike materials is the use of carbon steel where low alloy steels are intended, and the use of stainless steels where nickel based alloys are intended.

Risk-Based Inspection can aid in the prioritization of where to look for materials mix-ups if they are suspected. RBI will identify those equipment items that are most subject to failure based on the mix-up, and will rank them in order of risk by using the consequences of failure as well as the likelihood. This allows a Positive Materials Identification (PMI)

program to be conducted in a manner that is consistent with Risk-Based Management principles.

#### Step 1: Initial Evaluation

Performing the PMI prioritization scheme begins with some careful evaluation of candidate areas and equipment types or parts before initiating the work:

- Are there any construction or repair projects in which a lapse of quality controls of materials is particularly suspect?
- Are there any cases of known materials mix-ups that might cast suspicion on additional equipment fabricated or repaired under the same conditions?
- Is the mix-up associated with a particular component, such as welding materials, a batch of forged fittings, or particular castings?

Obviously, cases such as these would be good candidates for a comprehensive PMI program.

#### Step 2: Identify the Specific Mix-Up if Possible

The next step in the PMI prioritization process involves identifying what types of mix-ups are known or suspected to have occurred. For example, was the wrong grade of low alloy material used (e.g. 1<sup>1</sup>/<sub>4</sub> chrome steel used where the specification called for a 2<sup>1</sup>/<sub>4</sub> chrome steel)? Or was the wrong grade of high alloy material used (e.g. 316 stainless used where the specification called for Alloy 20)? Or are you

uncertain of what material might have been used but you know or suspect that mix-ups were made?

**Step 3: Identify the Damage Mechanism that will Affect the Wrong Material**

Use of a material other than that specified for the intended service often leads to increased in-service damage rates. Such mix-ups can also result in different damage types than were allowed for in the design. Some examples are:

- a. High Temperature Hydrogen Attack: Use of carbon steel or a lower alloyed steel than what was intended will lead to higher rates of attack.
- b. Sulfidation Corrosion: Use of carbon steel or lower chrome content steel than specified will lead to higher rates of corrosion.
- c. Acidic or other specific environment corrosion: Many highly corrosive environments use high alloy steels or non-ferrous based alloys for corrosion resistance. Use of the wrong grade of material can lead to much higher corrosion rates than intended.

**Stress Corrosion Cracking:** Use of austenitic stainless steels in place of nickel alloy steels may result in SCC, which might not have been considered a possibility with the specified material.

**Hydrogen Effects:** Use of the wrong grade of material may result in a variety of problems, including cracking of hard weld heat affected zones, or blistering in plate materials.

**Step 4: The "What-if" Analysis**

Use the RBI tools outlined in this BRD to perform the "what-if" analysis. Evaluate the suspect equipment using the appropriate Technical Modules for the damage mechanisms identified in Step 3. Be sure that the input materials, corrosion rates, cracking susceptibilities, etc., are for the suspect "wrong" material, not the specified material. If you are not sure what material may have been mistakenly installed, it is suggested that the "what-if" analysis use a worst case scenario, for example, carbon steel substituted in a system subjected to high temperature hydrogen attack. Depending on the exact scenario involved, there may be high technical module subfactors calculated for all equipment in the study. However, some will be higher than others, and the consequences associated with some equipment will be higher than others. This will generate a risk-based ranking for evaluation of equipment based on the highest risk first.

**Step 5: The PMI Process**

Positive materials identification can use several tools to identify wrong materials. If the suspect mix-up is substitution of a ferritic stainless steel for an austenitic stainless steel, the simple use of a magnet can quickly screen for mix-ups. Other tools include X-ray fluorescence (XRF) devices to analyze for the approximate content of heavier elements such as iron, nickel, chromium, and molybdenum. In other cases where more accuracy is needed, optical emission spectroscopy

(OES) devices are now available in field portable packages. These instruments can analyze the content of lighter elements, particularly carbon, to identify if the correct grade of steel is used. If the mix-up is suspected to involve welding materials, radiography can locate welds in insulated pipe without removing all the insulation.

The exact methods used for PMI and the extent of testing required will depend on the particular situation and is beyond the scope of this BRD.

## 9.4 APPROACH TO INSPECTION PLANNING

This is one of many possible approaches to inspection planning. The method of planning is by necessity different for different damage mechanisms. For example, a thinning mechanism implies that there is a finite life of the equipment during which inspections must be performed. Stress corrosion cracking, if inspected, found, and repaired, does not necessarily imply that the equipment has a fixed remaining life.

### 9.4.1 Method—Thinning Mechanisms:

Implicit in the "*ar/t*" lookup tables is a remaining life. When the damage factor rises to 10 or higher with 4 or more "highly" effective inspections, then the equipment is at or near the end of its life. In other words, there have been enough inspections to have relative certainty about the corrosion rate, and additional inspections no longer improve the damage factor. The inspection planning method solves for the number of years at which this point occurs (roughly  $ar/t = 0.4$ , with corrections for pressure and corrosion allowance). If this value is one year or less, a "diagnostics" module is called to provide a warning that based on the entered corrosion rate, age, and number of inspections, the equipment is already at or near its end of life. Careful data checking and/or confirmation of equipment condition are recommended.

If the remaining life is greater than one year, determine the number of inspections needed to achieve a high confidence in the corrosion rate over the remaining life of the equipment. This is expressed as the number of inspections of whatever effectiveness has been performed in the past, assuming that this is the "preferred" inspection type for this plant. The number of inspections can easily be converted to an equivalent number of inspections of a different effectiveness, based on the following relationships:

One "highly effective" is equivalent to two "usually effective," is equivalent to four "fairly effective."

If CUI is applicable in addition to internal thinning, the target damage factor is set to 5 for each mechanism so that the combined mechanisms will not lead to a damage factor greater than 10.

**9.4.2 Method—Stress Corrosion Cracking:**

Determine the current technical module subfactor. If this is less than 10, then use the SCC module “escalation” factor (years since last inspection) of 1.1 to determine the number of years until a TMSF of 10 will be reached. As a default, perform a “Fairly” effective inspection at that time as a check on the SCC condition.

If the current TMSF is greater than 10, use the relationships in Table 9-15 to determine the inspection level required.

It is recommended that the inspection be performed within three years of the last inspection, or as soon as practical if more than three years has elapsed.

**9.4.3 Method—Furnaces Inspection Planning:****Part 1. Long Term Damage:**

If the current TMSF is less than 10, increment  $t_i$  (operating hours) by 10,000 (~1 year) until a TMSF of 10 is reached. The number of increments is the time to the next inspection,  $T_{insp}$ . Use Table 9-16 to determine inspection requirements:

If the current TMSF is greater than 10, use the following relationships to determine the inspection level required:

It is recommended that the inspection be performed within three years of the last inspection, or as soon as practical if more than three years has elapsed.

**Part 2. Short Term Damage:**

For the short term damage TMSF, perform the following actions:

**9.4.4 Method—High Temperature Hydrogen Attack:**

For HTHA, the TMSF may already indicate that damage has occurred, or it may indicate susceptibility. Based on the TMSF, perform the actions listed in Table 9-19.

Table 9-15—Relationship Between the Level of Inspection and the Technical Module Subfactor

| Current SCC TMSF              | Inspection Level Recommended           |
|-------------------------------|----------------------------------------|
| $10 < \text{TMSF} \leq 100$   | Perform “Fairly Effective” Inspection  |
| $100 < \text{TMSF} \leq 1000$ | Perform “Usually Effective” Inspection |
| $1000 < \text{TMSF}$          | Perform “Highly Effective” Inspection  |

Table 9-16—Furnace Inspection Intervals With a TMSF Less Than Ten

| $T_{insp}$             | Inspection Method | Inspection Time  |
|------------------------|-------------------|------------------|
| $> = 20$ years         | Fairly Effective  | 5 years          |
|                        | Usually Effective | 10 years         |
|                        | Highly Effective  | 20 years         |
| $> = 10$ years, $< 20$ | Fairly Effective  | 3 years          |
|                        | Usually Effective | 6 years          |
|                        | Highly Effective  | 12 years         |
| $> = 5$ years, $< 10$  | Fairly Effective  | Not Allowed      |
|                        | Usually Effective | 3 years          |
|                        | Highly Effective  | 6 years          |
| $< 5$ years            | Fairly Effective  | Not Allowed      |
|                        | Usually Effective | Not Allowed      |
|                        | Highly Effective  | $T_{insp}$ years |

Table 9-17—Furnace Inspection Intervals With a TMSF Greater Than Ten

| Current Furnace TMSF        | Inspection Level Recommended                                                         |
|-----------------------------|--------------------------------------------------------------------------------------|
| $10 < \text{TMSF} \leq 50$  | Perform “Usually Effective” Inspection                                               |
| $50 < \text{TMSF} \leq 500$ | Perform “Highly Effective” Inspection                                                |
| $500 < \text{TMSF}$         | Perform “Highly Effective” Inspection, <i>plus</i> perform Remaining Life Evaluation |

Table 9-18—Actions Required for a Short-Term TMSF

| Short Term TMSF               | Action                                                                                       | Change to Long Term Inspection Frequency |
|-------------------------------|----------------------------------------------------------------------------------------------|------------------------------------------|
| $10 < \text{TMSF} \leq 500$   | Perform daily visual and burner adjustments.                                                 | No change                                |
| $500 < \text{TMSF} \leq 1000$ | Perform daily visual and burner adjustments.                                                 | Increase frequency by $1\frac{1}{2}$     |
| $10 < \text{TMSF} \leq 500$   | Perform thermography or add skin thermocouples, Perform daily visual and burner adjustments. | Increase frequency by 2.                 |

Table 9-19—Actions Required for HTHA

| TMSF                          | Action or Inspection                                 | Frequency |
|-------------------------------|------------------------------------------------------|-----------|
| $= 10,000$                    | Engineering assessment with appropriate repairs ASAP | ASAP      |
| $= 2,000$                     | "Usually Effective" inspection                       | 3 years   |
| $500 \leq \text{TMSF} < 2000$ | "Usually Effective" inspection                       | 6 years   |
|                               | "Fairly Effective" inspection                        | 3 years   |
| $100 \leq \text{TMSF} < 500$  | "Usually Effective" inspection                       | 12 years  |
|                               | "Fairly Effective" inspection                        | 6 years   |
| $10 \leq \text{TMSF} < 100$   | "Usually Effective" inspection                       | 20 years  |
|                               | "Fairly Effective" inspection                        | 10 years  |
| $\text{TMSF} < 10$            | No inspection                                        | N/A       |

## Section 10—Plant Database Structure

### 10.1 INFORMATION REQUIRED FOR RBI ANALYSIS

A quantitative RBI analysis requires a complete description of the design, fabrication, service conditions, and inspection program for each item of equipment to be evaluated. To insure that the analysis produces results that are accurate, reproducible, and consistent from one study to the next, a clear definition must be established for each item of data used in the analysis. All data collection must be performed by trained and knowledgeable persons.

The amount of data needed for a qualitative analysis is much less extensive, but the accuracy requirements are similar. If a consistent definition is used for the data collected, the information gathered for the qualitative analysis can become the basis for a subsequent quantitative analysis.

The datasheets presented as an Appendix at the end of this chapter are an example of the instruments that can be used to collect the information required for an RBI analysis. The full datasheet consists of four pages, and a completed datasheet is required for each equipment item. Section 10.2 discusses the use of the datasheet and provides definitions for the data entries to aid in standardizing the analysis. Section 10-2 lists some suggested sources for this data.

In some cases, groupings of possible responses, referred to as "Categories," are provided to describe the condition or characteristic being evaluated (e.g., < 10, 10 to 30, > 30, etc.). Establishing categories of this type simplifies data gathering and improves the consistency of the evaluation.

The sample datasheet can provide for all the information needed for most evaluations. Occasionally, however, evaluation of a specific damage mechanism may require some additional data. When such input is needed, the data requirements will be defined in the Technical Module for that damage mechanism.

A specialized datasheet can be developed and issued specifically for the study to be conducted. Such a datasheet should incorporate the data for all anticipated damage mechanisms and omit any entries on the sample datasheet that do not apply.

It is assumed that the RBI analysis will normally be performed using a computer. In this chapter, protocols are presented that will permit the RBI analysis to be programmed correctly. The developed protocols must be followed methodically for a computer analysis to perform properly.

### 10.2 COMPONENTS OF THE RBI DATASHEET

The datasheet in the Appendix to this chapter consists of the following six sections:

- a. **Heading**—Description of the specific equipment item and a listing of some of the primary data sources.
- b. **Universal Information**—Information that applies to all equipment items in the study. This section need only be completed once.
- c. **Mechanical Information**—Data that define the design and fabrication of the item.
- d. **Process Information**—Information concerning the process, the process fluids, and the impact of process conditions on the equipment item.
- e. **Inspection/Maintenance Information**—A summary of the item's significant inspection and maintenance history.
- f. **Safety System Information**—Record of any detection and/or mitigation devices that serve to protect the equipment item.

The data entries required in each of these sections are described below. The numbers in parenthesis in the following section correspond to the numbers in the data fields in the datasheet.

#### 10.2.1 Heading

##### 10.2.1.1 Equipment No. (1)

The Equipment Number is the primary identifier of an equipment item throughout the RBI analysis. Where possible, the equipment number assigned by the plant should be used. If no number exists (e.g., piping runs), a numbering system should be established and a unique number assigned to each item. Some equipment items require a suffix for full identification, for example, to differentiate between the shell or tube side of heat exchangers. Examples of these suffixes are listed below. Others may be required for special circumstances.

|                          |             |
|--------------------------|-------------|
| Heat exchanger-shell     | E-XXX-S     |
| Heat exchanger-tube      | E-XXX-T     |
| Heat exchanger-multipass | E-XXX-1...n |
| Column top               | T-XXX-TOP   |
| Column bottom            | T-XXX-BTM   |
| Reactor-operating        | R-XXX-OP    |
| Reactor-regeneration     | R-XXX-REG   |

Each item of equipment that is normally on line and operating should be listed separately. For example, if the plant has two tower reboilers and both are normally in service, then the two exchangers should be recorded as separate equipment items. On the other hand, if one of the two exchangers is an installed spare that is normally not operated, only one equipment item should be listed.

### 10.2.1.2 Category (2)

Each equipment item must be assigned to a category for which generic failure frequency values are available. Generic data are available for the equipment categories listed below. The name of the category that most closely describes the equipment item being evaluated should be recorded.

| Category | Equipment Item                                                 |
|----------|----------------------------------------------------------------|
| Column   | Distillation column, absorber, stripper, and similar vessels   |
| Compr-1  | Compressor, centrifugal                                        |
| Compr-2  | Compressor, reciprocating                                      |
| Filter   | Standard type of filters and strainers                         |
| Fin/Fan  | Fin/fan type heat exchangers                                   |
| HX-Shell | Shell side of condensers, reboilers, and other heat exchangers |
| HX-Tube  | Tube side of condensers, reboilers, and other heat exchangers  |
| Pipe     | Piping, any service                                            |
| Pump-1   | Centrifugal pump, single seal                                  |
| Pump-2   | Centrifugal pump, tandem/double seal                           |
| Pump-3   | Reciprocating pump                                             |
| Reactor  | Reaction vessel                                                |
| Tank     | Low pressure storage vessel                                    |
| Vessel   | Pressure vessel, any service                                   |

### 10.2.1.3 Description (3)

The equipment item should be described in enough detail to provide clear identification for an analyst who may not be thoroughly familiar with the process. When the nomenclature normally used by the plant is sufficiently descriptive, it should be used (e.g., Debutanizer, Splitter Reflux Pump, Ethane Feed Vaporizer, etc.). On occasion, it may be necessary to expand the plant nomenclature somewhat.

For piping, a "from," "to" description is recommended (e.g., from V-402 to P-411). At least one equipment item number should be included in the description to facilitate locating the pipe segment on a P&ID.

### 10.2.1.4 No. of Items (4)

Assuming that each operating item is listed separately as specified in Equipment No. (see 10.2.1.1), this entry will normally be 1.0.

Exceptions should be made when the operating conditions, the equipment design, or the item's physical dimensions dictate that the system can be better represented as two or more subsections. For example, if the service of a reaction vessel alternates between its reactor function and a catalyst regeneration function, and the operating conditions of the two functions are quite different, the vessel should be treated as two subsections. Each subsection would be analyzed separately, based on its own operating conditions, upset potential, etc. The fraction of the time that the vessel is in each service would determine the No. of Items entry for each subsection. The sum of the two entries should equal 1.0.

Distillation columns often merit treatment as two or more subsections. If the column has sections with different diameters or different materials of construction, each part should be treated separately. The fraction of the total length in each portion of the column would determine the No. of Items entry.

Even if the column is of uniform diameter and material, it should be treated as two half-columns if the difference in operating temperature between the top and bottom of the column exceeds 50°F (28°C). Temperature differences of this magnitude result in a significantly different composition of the top and bottom streams, which in turn can affect consequence calculations, rate of progress of damage mechanisms, etc.

### 10.2.1.5 PID No. (5)

When Process & Instrument Drawings are available, the number of the PID that includes the subject equipment item should be recorded. This information can be useful during the analysis.

### 10.2.1.6 PFD No. (6)

When Process Flow Diagrams are available, the number of the PFD that shows the subject Equipment Item should be recorded.

### 10.2.1.7 Stream No. (7)

Process Flow Diagrams normally identify major process streams and provide information about stream composition, conditions, flow rates, etc. When this information is available, the stream designation shown on the PFD should be recorded.

For equipment items that have multiple streams entering and leaving them, the incoming stream that represents the major portion of the flow or inventory should be recorded.

## 10.2.2 Universal Information

### 10.2.2.1 Project (8)

This entry is provided for project identification. Project name, project number, computer file number, or any appropriate identifier may be used.

**10.2.2.2 Plant Condition (9)**

This element considers the current condition of the facility being evaluated. The factors to be considered and the definition of the four categories are given in Section 8.3. The letter representing the appropriate category should be circled.

**10.2.2.3 Winter Daily Low Temperature (10)**

This value is used to determine whether a penalty should be assessed for cold weather operation. The average daily low temperature during the coldest month at the plant site is used to determine the magnitude of the penalty. Meteorological records for the site should be used to determine the average daily low temperature, if they are available. If records are not available, the average temperature might be determined by contacting the local weather bureau, extrapolating data from nearby regions or interviewing plant personnel.

**10.2.2.4 Seismic Activity (11)**

A plant located in a seismically-active area has a very slightly higher probability of failure than facilities outside such areas, even when the plant has been designed to appropriate standards. The level of concern is related to the probability of an earthquake, which in turn is indicated by the Seismic Zone. If the Seismic Zone is not known, it can be found in ANSI, A58.1, 1982.

The Seismic Zone in which the plant is located should be recorded.

**10.2.3 Mechanical Information**

This section provides information concerning the design and fabrication of all equipment items. More details are provided in Section 8.3 to assist in completing the datasheet.

The unit of measure (inches, millimeters, etc.) should be indicated where appropriate. In general, the RBI calculations have been designed using English units.

**10.2.3.1 Thickness (12)**

The original wall thickness should be recorded.

If the wall thickness varies over the length of the item, as might occur in a distillation column, the column should be divided into parts (i.e., top and bottom) and the thickness of each section recorded.

**10.2.3.2 Length (13)**

The primary purpose for recording the physical dimensions of equipment items is to permit calculation of equipment volume and, in turn, process inventory. Great accuracy is not required to arrive at meaningful results. Consistency in determining what to measure is more important.

The following rules include a number of simplifying assumptions to minimize the effort required to gather the data:

| Equipment Type        | Measure                                                                                                                                                                                                                                                                                                                                                                                  |
|-----------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Pressure vessels      | Length of cylindrical section, excluding heads.                                                                                                                                                                                                                                                                                                                                          |
| Columns               | For columns of uniform diameter that are treated as a single equipment item, the total length, excluding heads.<br><br>For columns of uniform diameter that are treated as two half-columns, one-half the total length, excluding heads.<br><br>For columns with a reduced section, the length of the specific section. Include the transition section with the larger diameter portion. |
| Heat exchanger, shell | Length, excluding channel(s) and head.                                                                                                                                                                                                                                                                                                                                                   |
| Heat exchanger, tube  | Length of the channel(s) plus the tube length in the shell.                                                                                                                                                                                                                                                                                                                              |
| Pumps and compressors | Zero (these items are assumed to have zero volume).                                                                                                                                                                                                                                                                                                                                      |
| Tanks                 | Height                                                                                                                                                                                                                                                                                                                                                                                   |
| Piping                | Total length of the pipe segment, including any branches.                                                                                                                                                                                                                                                                                                                                |

**10.2.3.3 Primary Diameter (14)**

(See Equipment Type and Measurement in the following table.)

| Equipment Type        | Measure                                                                                                                                                                                                          |
|-----------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Vessels, columns      | Inside diameter.                                                                                                                                                                                                 |
| Heat exchanger, shell | For shells of uniform diameter, the inside diameter.<br><br>For kettle-type, etc., the maximum dimension perpendicular to length. For double pipe, the diameter of the outer pipe.                               |
| Heat exchanger, tube  | For double pipe, the diameter of the inner pipe. For all other types of exchangers, the channel diameter. (Note: The non-tube portion of the tube bundle diameter is compensated for in the volume calculation.) |
| Pumps, compressors    | Zero                                                                                                                                                                                                             |
| Piping                | Nominal diameter                                                                                                                                                                                                 |

**10.2.3.4 Other Diameter (15)**

This field is used only for heat exchanger shells of non-uniform diameter, such as kettle-type exchangers. The channel diameter is to be recorded.



**10.2.3.5 No. of Trays (16)**

The number of trays in a distillation column is used in the calculation of column inventory. When columns of uniform diameter are analyzed as two separate sections, it can be assumed that one-half the trays are in each section. For columns with a reduced section, the actual number of trays in each section should be recorded.

**10.2.3.6 Fabrication Date (17)**

The item's fabrication date is used for age-related factors and to define the Code that was in place at the time of fabrication.

**10.2.3.7 Fabrication Code (18)**

The Fabrication Code under which the equipment item was designed and built should be recorded.

**10.2.3.8 Status of Code (19)**

The status of the Code (if any) against which the equipment item was designed and fabricated is addressed here. Again, definitions of the categories are given in Section 8.3.

**10.2.3.9 Vessel Lining (20)**

This field specifies whether the equipment item has an interior coating or lining. For all lined vessels, the material of construction of the lining should be recorded.

**10.2.3.10 Design Pressure (21)**

The design pressure of the equipment item should be recorded. If modifications to the item since its original fabrication have changed the design pressure, the current value should be listed.

**10.2.3.11 Design Temperature (22)**

The design temperature of the equipment item should be recorded. Items designed for low temperature service may have a minimum design metal temperature and a maximum design temperature. If available, both temperatures should be recorded.

**10.2.3.12 Design Life (23)**

Equipment items that are subject to aggressive damage mechanisms, such as severe corrosion or fatigue problems, will often be designed for a finite life. If such was the case for the item being evaluated, that design life should be listed.

If there is no evidence that the item was designed for a finite life, "40 years" should be recorded.

**10.2.3.13 Time in Current Service (24)**

Self-explanatory.

**10.2.3.14 Insulation (25)**

Insulated items may be subject to external corrosion under the insulation. "Yes" should be circled if the equipment item is fully or partially insulated, with any type or thickness of insulation.

**10.2.3.15 Exterior Coating (26)**

This question need only be answered for insulated items. The question refers to an external coating under the insulation, and it determines whether an item should receive credit for additional resistance to corrosion under insulation. A "Yes" answer requires a high quality "immersion grade" coating of the type described in NACE Publication 6H189, not just a single coat of primer.

**10.2.3.16 Pipe Exchanger (27)**

Double pipe heat exchangers require a different formula for calculation of volume than conventional exchangers. This field flags double pipe exchangers.

**10.2.3.17 Material of Construction (28)**

Material of construction is a primary consideration for evaluating several damage mechanisms. A complete designation of the material should be recorded (A-516-70, A-240-304, etc.) to assure proper analysis.

For most equipment items, the material of construction will be recorded on the first line, listed as "Shell." The additional lines permit definition of the various components of heat exchangers.

For each line, choices are provided to indicate whether the item was normalized and tempered, whether it received post weld heat treatment, and whether the material was produced to fine grain practice. The appropriate response to each choice should be circled.

**10.2.3.18 Complexity of Fabrication (29)**

The complexity of the fabrication of an equipment item influences the item's probability of failure. The greater the number of potential failure points, the greater the anticipated failure frequency.

Definitions for each of the terms listed in this element are given in Section 8.3.3. A count should be made for each of the listed characteristics.

**10.2.4 Process Information**

This section provides process and operating information for all equipment items. Definition of terms and instructions for completing the datasheet are included.

The unit of measure ( $\text{Kg/m}^3$ , psig, etc.) should be indicated where appropriate. Since the RBI calculations have been designed using English units, it would be appropriate to convert any metric measurements.

#### 10.2.4.1 Inventory Group (30)

Inventory Group is a term used to designate a grouping of equipment items that can be remotely isolated from other sections of the plant in an emergency situation. The Inventory Group concept is used in the calculation of consequence area. It is assumed that the total inventory of all equipment within the Inventory Group is potentially available for release in the event of a pressure boundary failure anywhere within the limits of the Inventory Group.

When motor-operated valves (MOV's) are in place that can be operated from the control room or a similar remote location, they will determine the boundaries of Inventory Groups.

When MOV's are locally controlled or are unavailable, it is usually possible to isolate sections of a plant by closing remotely-operated control valves and manual valves in adjoining areas. While the security of isolation using control valves and manual valves is poorer than with remotely-operated MOV's, this method can be expected to restrict flow from other areas significantly enough to define an Inventory Group.

The layout of the plant should be considered whenever control valves, locally operated MOV's, or valves in adjacent areas are used in defining an Inventory Group. For example, in a distillation system in which the towers are widely separated, one tower and its attendant equipment might be considered as an Inventory Group. Conversely, if all towers are closely spaced in a single structure, the entire distillation train should be considered a single Inventory Group.

#### 10.2.4.2 Crude Oil Characteristics or Stream Composition (31)

The composition of the process fluid being handled by the equipment is a key factor in determining possible damage mechanisms. Depending upon the type of stream, the entry could be a list of the two or three major components, a boiling point range, or a description using commonly understood terminology. If the stream includes any constituent known to cause corrosion or other problems, these constituents should be noted in Entry 35 (Concentration %). Additional information is provided in Section 8.2.

#### 10.2.4.3 Representative Component (32)

Experience has shown that some equipment should be analyzed as two separate pieces. This is especially true for equipment that has liquid and gas in two distinct phases. In general, columns or towers are typically split into two pieces—each piece having its own representative fluids at different process conditions.

When choosing a representative fluid, several key physical properties are needed for the fluid at process conditions:

- Normal boiling point (at atmospheric conditions).
- Auto-ignition temperature.
- Molecular weight.

- Heat capacity constants.
- Density.
- Toxic fraction.

In the RBI consequence models, any fluid can be used for the release rate portion of the calculation, provided the above properties are known. For the final portion of the consequence analysis (calculation of damage area), the fluid must be linked to a pre-defined fluid. This list appears in Section 7. When linking the fluid of interest to one on the pre-defined list, it is important to refer to a fluid that has a similar boiling point and molecular weight, as these two parameters are critical in the final portion of the consequence analysis.

For mixtures, the properties of the representative fluid can be found by using the following approximation:

$$\sum_{all} X_i \times Property_i$$

where

$i$  = the constituent of the mixture and  $x_i$  is the mole fraction of the constituent

As a simplifying assumption in the RBI procedure, calculation of consequence area can be based on the properties of a single representative component rather than those of the actual mixed stream that may be present. The component chosen as representative would normally be the constituent of highest concentration, unless using a different component would result in a considerably greater consequence area.

#### 10.2.4.4 Operating Conditions

At various stages of the RBI analysis, both normal operating conditions and any potential upset conditions must be specified as described in the following paragraphs.

#### 10.2.4.5 Pressure (33)

The normal operating pressure entry is used in various consequence calculations and in determining the safety factor discussed in Section 8.3.3. When a range of operating pressures is employed, as may be the case in a plant producing a variety of product grades, the highest pressure normally specified should be recorded.

Pressure extremes under upset conditions should also be recorded if they are significantly different from normal operating pressure. Examples would include conditions where a vacuum might be imposed on a pressure vessel, or where the relief valve setting is much higher than normal operating pressure. The likelihood of occurrence of the upset should be judged based on the definitions presented under Likelihood (36) below. For equipment that induces a large pressure change (pumps, condensers, etc.) it is prudent to input the high-side pressure.

#### 10.2.4.6 Temperature (34)

The normal operating temperature is also used in consequence calculation and can be an important variable in several damage mechanisms. When a range of operating temperatures is employed, as may be the case in a plant producing a variety of product grades, record the most severe temperature normally specified (highest for high temperature operations, lowest for low temperature processes). Temperature extremes under upset conditions can have a profound effect on rate of damage for several damage mechanisms. The highest and lowest temperature that could occur should be recorded. The likelihood of occurrence should also be listed, as explained under Likelihood (36), below. For equipment that induces a large temperature change (heat exchangers, furnaces, etc.) it is best to input the average temperature across the equipment.

#### 10.2.4.7 Contaminant Concentration (35)

This entry is used to record the presence of constituents in the process stream that can create or contribute to a failure mechanism.

Significant changes in the concentration of key components or contaminants can make a major change in the rate of corrosion, stress corrosion cracking, etc. When such conditions exist, the percent concentration of the critical components under upset conditions should also be listed.

#### 10.2.4.8 Likelihood (36)

An upset conditions' impact on the probability of failure is a function of both the severity of the upset and the likelihood that such an upset may occur. For each of the three upset conditions above (pressure, temperature, and concentration), the likelihood category, A through D, should be assigned according to the following guidelines.

| Category | Likelihood of Occurrence                                                 |
|----------|--------------------------------------------------------------------------|
| A        | Condition has been observed in the facility in the past.                 |
| B        | Condition is judged likely to occur during the lifetime of the facility. |
| C        | Condition is judged likely to occur once in the lifetime of ten plants.  |
| D        | Condition is theoretically possible but judged very unlikely to occur.   |

#### 10.2.4.9 Initial State (37)

In the consequence calculations, determination of the quantity of process fluid released is very much dependent

upon whether the escaping material is a liquid or a gas at the conditions within the equipment item at the point of release. This is defined as the Initial State of the material.

The RBI procedure assumes that all streams are either liquid or gas at the point of release, not mixtures of the two.

For most equipment items, the primary consideration for determining Initial State is the physical state of the major incoming stream. (The incoming stream is used because it is always at the higher pressure.) For two-phase systems (such as condensers, phase separators, evaporators, reboilers), some judgment is needed to determine the initial phase. The assignment of initial state is based primarily on how the discharge model handles the initial state input. In most cases, choosing liquid is conservative, and may be preferred. Sometimes this may not be the appropriate default, particularly if a pipe containing a two-phase fluid is attached to a large inventory that is mostly a vapor, especially as pressure begins to drop in the system. For consistency of evaluation, the following rules are suggested to determine whether the stream is considered a Liquid or a Gas.

a. For Drums, Vessels, Reactors, Heat Exchanger-Shell, Heat Exchanger-Tube, and Filters:

Place a check mark under Liquid or Gas, based on the physical state of the major incoming stream.

b. For Columns, Pumps, and Compressors:

No entry is required.

c. For all Piping:

Designate Liquid or Gas based on the physical state of the material in the pipe. For piping that contains a mixture of liquid and gas, indicate the state of the primary component.

#### 10.2.4.10 Final State (38)

Consequence calculations are also quite dependent upon the physical state of the leaking material after release to the atmosphere (the Final State). Ambient temperature and the atmospheric boiling point of the material are the primary considerations for assigning the Final State. On the Gulf Coast in the summer, C4 and lighter materials would be considered as Gas. In the North in winter, C3 and heavier might be recorded as Liquid. The determination should be based on plant location and the physical properties of the representative component.

The RBI procedure assumes that the Final State of all leaking streams is either 100% liquid or 100% gas.

#### 10.2.4.11 % Liquid (39) % Vapor (40)

These values are used to define the quantity of liquid in tanks, vessels, heat exchangers, etc. When the level in the vessel is controlled, the normal reading of the level controller should be recorded.

For most equipment types other than columns, the level controller is usually located near the center of the vessel, so this reading approximates the percent liquid in the vessel. Columns are treated separately below.

All piping is considered to be either 100% liquid or 100% vapor, based on normal operating conditions. Only one of the two values need be entered.

#### **10.2.4.12 For Columns, Bottom Liquid Level (41)**

This field applies only to distillation towers and other columns.

The “% Liquid” entry alone does not define the liquid level in the bottom of a column. The “% Liquid” entry is based on the normal reading of the bottom level controller, so the total quantity of liquid is a function of the location of the nozzles for the level controller as well as the level controller set point. To calculate bottom liquid level, the distance from the bottom of the tower to the lower nozzle for the level controller must be added to the product of the distance between the lower and upper controller nozzles times the “% Level” indication. This calculation should be made for each column and recorded on the datasheet for that column.

#### **10.2.4.13 Liquid Density (42) Vapor Density (43)**

The densities at normal operating conditions are used for calculation of inventory. This is the only application for these values, and since inventory calculations are not highly dependent upon density values, a reasonable estimate is satisfactory.

#### **10.2.4.14 Number of Shutdowns Per Year (44)**

Shutdowns often create opportunities for operational errors and mechanical failures. The greater the number of shutdowns, the higher the probability of such failures.

The average number of planned and unplanned shutdowns per year should be recorded in this section. As defined in Section 8.3.4, planned shutdowns are outages for which Standard Operation Procedures for shutdown are employed. Unplanned shutdowns are those that occur with a minimum of prior planning. The entry should be based on the average number of shutdowns in each category over the last three years.

#### **10.2.4.15 Stability Ranking (45)**

The person conducting the RBI analysis will determine the stability ranking for each section of the facility according to the guidelines presented in Section 8.3.4. The stability ranking of the section of the plant that includes the equipment item being evaluated should be recorded on that item's datasheet.

#### **10.2.4.16 Conditions Affecting Relief Valves (46)**

The four entries on the datasheet dealing with relief valves are intended to assess whether design or process conditions exist that could prevent the relief system from functioning when needed. Section 8.3.4 should be consulted for definitions of each of the four entries.

The entries for each equipment item's datasheet should be based on the condition of the relief valve protecting that item.

#### **10.2.4.17 Data for Technical Modules (47)**

For some damage mechanisms, the rate of damage is a function of the concentration or phase of certain components or contaminants in the process stream. Any data needed to evaluate such damage mechanisms are recorded in this section of the datasheet.

The specific information needed will be listed in the Technical Module for the damage mechanism.

### **10.2.5 Inspection/Maintenance Information**

This section of the datasheet captures the inspection plan and the inspections actually conducted for each equipment item. Most of the normally used inspection procedures are listed, and blanks are provided to indicate which tests are employed and the frequency of testing. Space is also provided to indicate percent coverage of the test, where appropriate.

Inspection records for the equipment item should be reviewed to determine the actual level of inspection activity. Inspections scheduled but not performed would normally receive no credit, unless historical records indicate that the test has been conducted on a fairly regular interval over a reasonable period of time.

Space is also provided to record the pertinent maintenance history of the equipment item. Any major repairs or alterations should be noted and described briefly in the Comments section.

If inspection or maintenance activities have established a corrosion rate or other damage rate, that value should be recorded as Damage Rate. The damage types and damage mechanisms responsible for the deterioration should be noted on the data.

### **10.2.6 Safety System Information**

The consequence values calculated in the RBI procedure are adjusted to account for the effectiveness of any detection devices in the plant, and for all installed mitigation facilities.

As is the case with relief valves, one grouping of detection and mitigation devices might protect several equipment items. The level of protection is often not equal across all sections of a plant, however, so the datasheet for each equipment item includes a section for Safety Systems. The category that best describes the facilities available to that equipment item should be noted, based on the definitions in Table 7-6.

Any mitigation devices that serve to protect the equipment item should be noted. Some of the more common devices are listed. Any additional installed mitigation devices should be added to the datasheet.

### 10.3 RECOMMENDED SOURCES OF DATA FOR THE RBI DATASHEET

Table 10-1 shows a typical listing of the preferred source of data for each entry on the RBI datasheet, as well as the first and second alternate sources that can be used if the information is not available from the preferred source.

The recommendations shown should be modified by the user of the RBI procedure as required to fit the data sources available at the facility being analyzed. The most accurate and readily available source should be listed as the preferred source.

The purpose of developing a comprehensive listing of data sources is to standardize the analysis procedure. Undoubtedly, several people will be involved in data gathering and analysis. Variability between individuals can be minimized by providing well-defined rules and guidelines at each stage of the analysis.

### 10.4 PROCEDURES FOR INVENTORY CALCULATION

The normal working inventory of each equipment item is needed for consequence calculations. Standardized procedures are provided below for making these determinations. In many cases, simplifying assumptions have been made to minimize the effort required for the calculations. Absolute accuracy of inventory calculation is not as important in the risk prioritization procedure as consistency of procedure.

Procedures are presented by equipment type. In each case, methods are given for calculating total equipment volume and liquid volume. Vapor volume is considered to be the total volume of the equipment item minus the liquid volume; the volume of any equipment internals is disregarded.

#### 10.4.1 Column

##### 10.4.1.1 Total Volume

For towers of uniform diameter, volume should be calculated based on the length and diameter reported on the Datasheet. Volume of the top and bottom heads is disregarded. When the top and bottom halves of the tower are analyzed separately, the volume is divided evenly between the two portions.

For towers with a reduced section, the volume of each section should be determined separately based on its actual length and diameter. The transition area between the two diameters should be considered part of the larger diameter portion. Again, top and bottom head volume is disregarded.

#### 10.4.1.2 Liquid Volume

For trayed columns, liquid on the trays is added to the amount in the tower bottom to determine total liquid volume. Tower bottom liquid volume is based on the "Bottom Liquid Level" entry on the Datasheet, which is a calculation of the liquid height in the bottom of the tower. The quantity of liquid on each tray is calculated assuming an average liquid depth of 3 inches and an effective area of one-half the tower cross-sectional area (to account for downcomer area and liquid aeration on the tray). The number of trays is recorded on the Datasheet.

For packed columns, the liquid volume in the packed area is disregarded unless the column is operated liquid-full. For a liquid-full column, the full liquid volume is calculated. If the column is not liquid-full, only the quantity in the tower bottom is considered.

#### 10.4.2 Compressor

Compressors are considered to have no volume. However, during consequence calculations, they are considered to be connected to the appropriate Inventory Group.

#### 10.4.3 Heat Exchanger—Shell

##### 10.4.3.1 Net Volume

a. For all heat exchanger types, the Net Volume is the difference between the total volume of the shell and the volume occupied by the tube bundle. The tube bundle volume is assumed to be one-half the volume defined by the channel diameter and the shell length.

b. For exchanger shells of uniform diameter, the total volume of the shell is that of a cylinder of the length and diameter given on the Datasheet. Head volume is disregarded. Shell diameter and channel diameter are equal for this type exchanger.

c. For kettle-type exchangers and others of non-uniform diameter, total shell volume is assumed to be that of a cylinder of the "Primary Diameter" from the Datasheet. This value is the largest dimension perpendicular to the length of the exchanger. Channel diameter, given as "Other Diameter" on the Datasheet, is used to calculate tube bundle volume.

##### 10.4.3.2 Liquid Volume

The liquid volume of a heat exchanger shell is assumed to be the Net Volume of the shell times the "% Liquid" value reported in the Datasheet.

#### 10.4.4 Heat Exchanger—Tube

##### 10.4.4.1 Net Volume

The Net Volume is assumed to be one-half the volume of a cylinder of the channel diameter and tube length given on the Datasheet.

Table 10-1—Recommended Sources of Data for RBI Datasheet

| Universal Information                      |                         |                      |                 |
|--------------------------------------------|-------------------------|----------------------|-----------------|
| Mechanical Information                     |                         |                      |                 |
| Variable                                   | Preferred Source        | 1st Optional Source  |                 |
| Plant Condition                            | Professional            | Judgment of Observer |                 |
| Winter Temp                                | Weather Bureau Records  | Plant Records        |                 |
| Seismic Zone                               | ANSI A58.1, 1982        |                      |                 |
| Variable                                   | Preferred Source        | 1st Opt. Source      | 2nd Opt. Source |
| Thickness                                  | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Length                                     | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Primary Diameter                           | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Other Diameter                             | U-1                     | Fabrication Dwg.     | Design Sheet    |
| No. of Trays                               | Fabrication Dwg.        | Design Sheet         | —               |
| Fab. Date                                  | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Fab. Code                                  | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Design Pressure                            | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Design Temperature                         | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Design Life                                | Design Sheet            | —                    | —               |
| Time in Current Service                    | Maint. Records          | —                    | —               |
| Insulation                                 | P&ID                    | Design Sheet         | —               |
| Exterior Coating                           | Fabrication Dwg.        | Design Sheet         | —               |
| Pipe Exchanger                             | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Material of Construction                   | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Heat Treatment                             | U-1                     | Fabrication Dwg.     | Design Sheet    |
| Fine Grain Processing                      | U-1                     | Fabrication Dwg.     | Design Sheet    |
| No. of Nozzles                             | Fab. Dwg.               | P&ID                 | Design Sheet    |
| No. of welds, flanges, branches and valves | Piping Iso              | Est. from P&ID       | Field Check     |
| Inventory Group                            | P&ID                    | PFD                  | —               |
| Crude Character. or Stream Comp.           | PFD                     | Operations           | —               |
| Represent. Component                       | PFD                     | Operations           | —               |
| Operating Pressure                         | PFD                     | Operations           | Design Sheet    |
| Operating Temp.                            | PFD                     | Operations           | Design Sheet    |
| Upset Pressure                             | Operations              | —                    | —               |
| Upset Temperature                          | Operations              | —                    | —               |
| Likelihood                                 | Guidelines              | Operations           | —               |
| Initial State                              | PFD                     | Design Sheet         | Operations      |
| Final State                                | Guideline               | —                    | —               |
| % Liquid                                   | Operations              | —                    | —               |
| % Vapor                                    | Operations              | —                    | —               |
| Liquid Density                             | PFD                     | Design Sheet         | —               |
| Vapor Density                              | PFD                     | Design Sheet         | —               |
| Liquid Level                               | Operations              | —                    | —               |
| No. Planned SD                             | Plant Records           | —                    | —               |
| No. Unplanned SD                           | Plant Records           | —                    | —               |
| Stability Rank                             | Professional Judgment   | —                    | —               |
| RV Maint Program                           | Maint Records           | —                    | —               |
| Fouling Service                            | Operations              | Insp. Records        | —               |
| Corrosive Serv.                            | Operations              | Insp. Records        | —               |
| Data for Tech Mod                          | See Tech Mod for source | —                    | —               |
| Inspections                                | Insp. Records           | Insp. Plan           | —               |
| Maint. History                             | Maint Records           | —                    | —               |
| Safety System Info                         | Design Info             | Operations           | —               |

**10.4.4.2 Liquid (or Gas) Volume**

The tube side of a heat exchanger is assumed to be all liquid or all gas and 100% full. Therefore, the liquid or gas volume is equal to the Net Volume.

**10.4.5 Pipe Exchanger—Shell****10.4.5.1 Net Volume**

The outer pipe is considered the shell. The Net Volume is the outer pipe volume, based on its nominal volume and length, minus the inner pipe volume from the HX-Tube Datasheet.

**10.4.5.2 Liquid (or Gas) Volume**

Both the shell and tube side of pipe exchangers are assumed to be 100% full, so liquid or gas volume equals Net Volume.

**10.4.6 Pipe Exchanger—Tube****10.4.6.1 Total Volume**

Volume is based on the inner pipe's nominal diameter and length.

**10.4.6.2 Liquid (or Gas) Volume**

The tube side is assumed to be 100% full, so liquid or gas volume equals Total Volume of the inner pipe.

**10.4.7 Pipe****10.4.7.1 Total Volume**

The inside diameter of piping is a function of the pipe schedule. Schedule can usually be determined by consulting the piping specs for the plant. If this information is not readily available, a schedule should be assumed based on the operating conditions of the plant.

**10.4.7.2 Liquid (or Gas) Volume**

All piping is assumed to be 100% full and either all liquid or all gas. Liquid or gas volume is equal to total volume.

**10.4.8 Pump****10.4.8.1 Total Volume**

Like compressors, all pumps are assumed to have zero volume, but they are part of an Inventory Group, and have that inventory available in the event of a failure.

**10.4.9 Vessel****10.4.9.1 Total Volume**

Volume equals that of a cylinder of the length and diameter described on the Datasheet.

**10.4.9.2 Liquid Volume**

Liquid Volume equals Total Volume times the "% Liquid" entry on the Datasheet.

## RBI DATASHEET

Page 1

Equipment No. \_\_\_\_\_

## Heading

1. Equipment No. \_\_\_\_\_ 2. Category \_\_\_\_\_

3. Description \_\_\_\_\_ 4. No. of Items \_\_\_\_\_

5. PID No. \_\_\_\_\_ 6. PFD No. \_\_\_\_\_ 7. Stream No. \_\_\_\_\_

## Universal Information

8. Project \_\_\_\_\_

9. Plant Condition    A        B        C        D

10. Winter Daily Low Temp \_\_\_\_\_ °F.    11. Seismic Zone \_\_\_\_\_

## Mechanical Information

12. Thickness \_\_\_\_\_ mm-in    21. Design Pressure \_\_\_\_\_ KPAG-PSIG

13. Length \_\_\_\_\_ m-ft    22. Design Temperature \_\_\_\_\_ °C - °F

14. Primary Diameter \_\_\_\_\_ mm - in    23. Design Life \_\_\_\_\_ Years

15. Other Diameter \_\_\_\_\_ mm - in    24. Time in Current Service \_\_\_\_\_ Years

16. No. of Trays \_\_\_\_\_    25. Insulation                      Yes                      No

17. Fabrication Date \_\_\_\_\_    26. Exterior Coating                      Yes                      No

18. Fabrication Code \_\_\_\_\_    27. Pipe Exchanger                      Yes                      No

19. Status of Code                      A        B        C

20. Vessel Lining                      Yes        No

If Yes, MOC \_\_\_\_\_

## 28. Material of Construction:

Normalized  
Tempered

PWHT

Fine Grain  
ProcessingImpact Test  
Temperature

Shell \_\_\_\_\_    Y or N                      Y or N                      Y or N                      Y or N

Tubesheet \_\_\_\_\_    Y or N                      Y or N                      Y or N                      Y or N

Tubes \_\_\_\_\_    Y or N                      Y or N                      Y or N                      Y or N

## 29. Complexity of Fabrication

## For Equipment

No. of Nozzles \_\_\_\_\_

## For Piping

No. of Connections \_\_\_\_\_

No. of Injection Points \_\_\_\_\_

No. of Branches \_\_\_\_\_

No. of Valves \_\_\_\_\_



## RBI DATASHEET

Page 2

Equipment No. \_\_\_\_\_

## Process Information

30. Inventory Group. \_\_\_\_\_

31. Crude Oil Characteristics or Stream Composition \_\_\_\_\_

32. Representative Component \_\_\_\_\_

## Operating Conditions

|                                               | Normal Operation | Upset Conditions         |       | 36. Likelihood                         |
|-----------------------------------------------|------------------|--------------------------|-------|----------------------------------------|
|                                               |                  | Max                      | Min   |                                        |
| 33. Pressure (KPAG-PSIG)                      | _____            | _____                    | _____ | _____                                  |
| 34. Temperature (°C -°F)                      | _____            | _____                    | _____ | _____                                  |
| 35. Contaminant Concentration (%)             | _____            | _____                    | _____ | _____                                  |
|                                               | <b>Liquid</b>    | <b>Gas</b>               |       |                                        |
| 36. Upset Likelihood                          | _____            | _____                    |       |                                        |
| 37. Initial State (in Equipment)              | _____            | _____                    |       |                                        |
| 38. Final State (after Release)               | _____            | _____                    |       |                                        |
| 39. % Liquid _____                            |                  | 42. Liquid Density _____ |       | Kg/m <sup>3</sup> – Lb/ft <sup>3</sup> |
| 40. % Vapor _____                             |                  | 43. Vapor Density _____  |       | Kg/m <sup>3</sup> – Lb/ft <sup>3</sup> |
| 41. For columns only, Bottom Liq. Level _____ |                  | _____ m - ft             |       |                                        |
| 44. No. of Shutdowns per year:                |                  | 45. Stability Ranking:   |       |                                        |
| Planned _____                                 |                  | A B C D                  |       |                                        |
| Unplanned _____                               |                  |                          |       |                                        |

## 46. Conditions Affecting Relief Valves:

| RV Maint. Program | A | B | C | Corrosive Service  | Yes | No |
|-------------------|---|---|---|--------------------|-----|----|
| Fouling Service   | A | B | C | Very Clean Service | Yes | No |

## 47. Data for Technical Modules:

| Corrosive Species or Containment | %Concentration | Phase |
|----------------------------------|----------------|-------|
| _____                            | _____          | _____ |
| _____                            | _____          | _____ |
| _____                            | _____          | _____ |
| _____                            | _____          | _____ |

Equipment No. \_\_\_\_\_

| Inspection Procedure | Scheduled | Interval Between Tests |  | % Coverage |
|----------------------|-----------|------------------------|--|------------|
|                      |           | Actual                 |  |            |
| Visual - External    | _____     | _____                  |  | _____      |
| Visual - Internal    | _____     | _____                  |  | _____      |

## RBI DATA SHEET

Page 3

|                                           |       |       |       |
|-------------------------------------------|-------|-------|-------|
| Ultrasonic testing-External               | _____ | _____ | _____ |
| Ultrasonic testing-Internal               | _____ | _____ | _____ |
| Automated ultrasonic testing              | _____ | _____ | _____ |
| Shear wave ultrasonic testing             | _____ | _____ | _____ |
| Acoustic emission testing                 | _____ | _____ | _____ |
| Radiographic testing                      | _____ | _____ | _____ |
| Eddy current testing                      | _____ | _____ | _____ |
| Wet fluorescent magnetic particle testing | _____ | _____ | _____ |
| Liquid penetrant testing                  | _____ | _____ | _____ |
| IRIS-Internal                             | _____ | _____ | _____ |
| Hydrostatic testing                       | _____ | _____ | _____ |
| For insulated items:                      |       |       |       |
| Selective stripping                       | _____ | _____ | _____ |
| Complete stripping                        | _____ | _____ | _____ |
| Radiography                               | _____ | _____ | _____ |
| For rotating equipment:                   |       |       |       |
| Periodic vibration measurement            | _____ | _____ | _____ |
| Continuous vibration measure              | _____ | _____ | _____ |
| Other procedures _____                    | _____ | _____ | _____ |
| _____                                     | _____ | _____ | _____ |
| _____                                     | _____ | _____ | _____ |
| Inspections not performed _____           | N/A   | N/A   | N/A   |

**Maintenance History:**

|                   |           |                         |
|-------------------|-----------|-------------------------|
| Major Repairs     | Yes or No | Damage Rate _____       |
| Major Alterations | Yes or No | Damage Type _____       |
| Item Replaced     | Yes or No | Damage Mechanisms _____ |

Comments: \_\_\_\_\_

\_\_\_\_\_

Equipment No. \_\_\_\_\_

**Safety System Information****Detection Classification:**

|                                          |       |
|------------------------------------------|-------|
| A Process Instrumentation                | _____ |
| B Suitably Located Detectors             | _____ |
| C Visual Detection or Marginal Detectors | _____ |

**Isolation System:**

## RBI DATA SHEET

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- |   |                                               |       |
|---|-----------------------------------------------|-------|
| A | Directly activated isolation/shutdown system  | _____ |
| B | Operator activated isolation remote from leak | _____ |
| C | Isolation by manually-operated valves         | _____ |

## Mitigation Devices in Place:

- |                                  |       |
|----------------------------------|-------|
| Fire Water Monitors              | _____ |
| Sprinkler System                 | _____ |
| High Volume Deluge System        | _____ |
| Foam System                      | _____ |
| Blast Walls                      | _____ |
| Containment for Liquid Spills    | _____ |
| Fireproofing of Structural Steel | _____ |
| Other (specify)                  | _____ |
| _____                            | _____ |
| _____                            | _____ |

## Section 11—Technical Modules

### 11.1 TECHNICAL MODULE INTRODUCTION

The petrochemical industry lacks a specific experience database in regards to failure frequency categorized by equipment type and specific process environment. As a result, the Base Resource Document (BRD) procedure modifies a generic failure frequency for each equipment type by a factor related to the type of potential in-service degradation occurring in the particular service and the type of inspection and/or monitoring performed. The BRD uses the term "Technical Module" to describe the methodology by which this modification factor is calculated. The following Technical Modules appear as appendices to this document:

- Thinning—Appendix G
- Stress Corrosion Cracking—Appendix H
- High Temperature Hydrogen Attack—Appendix I
- Furnace Tubes—Appendix J
- Mechanical Fatigue (Piping Only)—Appendix K
- Brittle Fracture—Appendix L
- Equipment Linings—Appendix M
- External Damage—Appendix N

These Technical Modules cover the general procedures for handling the degradation type and detailed supplemental technical information for specific degradation mechanisms. The Technical Modules have built into them the ability for updating the modification factor (referred to as the "technical module subfactor" or TMSF) based on the most recent inspection and monitoring information available. If more than one of the general damage types are potentially present, the individual TMSF are additive.

For example:

$$\text{TMSF}_{\text{Thinning}} + \text{TMSF}_{\text{SCC}} + \text{TMSF}_{\text{HTHA}}$$

If the Furnace Module is used for determination of  $\text{TMSF}_{\text{Furnace}}$ , the  $\text{TMSF}_{\text{Furnace}}$  should replace the  $\text{TMSF}_{\text{Thinning}}$ , for example:

$$\text{TMSF}_{\text{Furnace}} + \text{TMSF}_{\text{SCC}} + \text{TMSF}_{\text{HTHA}}$$

The overall equation for determining the cumulative TMSF is:

$$\text{TMSF}_{\text{Final}} = \text{TMSF}_{\text{Thinning}} + \text{TMSF}_{\text{SCC}} + \text{TMSF}_{\text{HTHA}} + \text{TMSF}_{\text{Fatigue}} + \text{TMSF}_{\text{BF}} + \text{TMSF}_{\text{Lining}}^* + \text{TMSF}_{\text{External}}$$

\*The smaller of  $\text{TMSF}_{\text{Lining}}$  or  $\text{TMSF}_{\text{Thinning}}$  should be used if both are active.

The Technical Modules are intended to support the Risk-Based Inspection methodology by providing a screening tool to determine inspection priorities, and to optimize inspection efforts. The technical modules do not provide a definitive "Fitness-for-Service" assessment of the equipment involved. The basic function of the module is to statistically evaluate the amount of damage that may be present and the effectiveness of inspection activity. The technical module subfactors calculated are based on probability theory, but are not intended to reflect the actual probability of failure for the purposes of reliability analysis. The technical module subfactors reflect a relative level of concern about the equipment based on the stated assumptions of the module.

### 11.2 TECHNICAL MODULE FORMAT

The following sections are included in each Technical Module. A brief description of each section is provided in the following:

#### 11.2.1 Scope

This section describes the scope and limitations of the Technical Module, including the damage types and mechanisms that are covered.

#### 11.2.2 Technical Module Screening Questions

All equipment should be considered for thinning and SCC. Simple screening questions provided at the beginning of the HTHA, Furnace, Brittle Fracture, Mechanical Fatigue, External Damage, and Lining modules are used to determine whether these modules apply. The purpose of the technical modules is to determine a technical module subfactor based on equipment specific knowledge such as a measured corrosion rate or susceptibility to SCC based on experience and/or inspection history.

If little or no reliable inspection information is available, additional screening questions are provided within the Technical Modules for thinning and SCC to determine whether or not specific damage mechanisms are possible in the equipment. Supplements to the Technical Modules for specific damage mechanisms provide a conservative estimate of the corrosion rate when a corrosion rate is not available on the basis of measurements obtained from one or more effective inspections. These screening questions require yes/no answers only. If the answers to the screening questions are yes, additional information will be required to use the supplements to estimate a conservative corrosion rate.

##### 11.2.2.1 Basic Data

The required data needed to determine the technical module subfactor is summarized in the basic data tables. The

basic data tables describe information required for determination of the TMSF.

### 11.2.2.2 Basic Assumptions

A description of the applicable models of damage rate and severity, along with the assumptions made in the models, is provided. These models are used in the calculation of the technical module subfactors. The assumptions made are appropriate to the development of a screening tool, but may not be appropriate for a fitness-for-service evaluation.

### 11.2.2.3 Determination of Technical Module Subfactor

Instructions for use of the tables to determine the technical module subfactor are provided. A step by step flow diagram is provided to determine the final technical module subfactor using the look-up tables and equations included in the Technical Module.

### 11.2.2.4 Determination of Corrosion Rate or Susceptibility and Severity Index

A brief description of the methods used to determine the corrosion rate or susceptibility to damage (or existence of damage) based on operating and process conditions.

### 11.2.2.5 Technical Supplement Screening Questions

When there are no effective inspection results by which to establish the damage state, screening questions are provided to guide the user to the appropriate section for specific damage mechanisms.

### 11.2.2.6 Inspection Effectiveness Category

A description of the categories of inspection effectiveness used to determine the technical module subfactor is provided. Suggested examples of typical inspection methods for each category are presented.

Table 11-1 describes the five inspection effectiveness categories:

The inspection effectiveness categories presented are meant to be examples and provide a guideline for assigning actual inspection effectiveness. The actual effectiveness of any inspection technique depends on many factors such as the skill and training of inspectors, and the level of expertise used in selecting inspection locations.

### 11.2.3 Determination Of Technical Module Subfactor (TMSF)

A table containing the technical module subfactors can be found at the end of each Technical Module.

### 11.2.4 Adjustments To TMSF

Adjustments to the TMSF may be required for potential corrosion at injection points/deadlegs or corrosion under insulation. In addition, adjustments may be made for on-line monitoring.

### 11.2.5 Specific Damage Mechanism Sections

Each specific damage mechanism section provides guidance with regard to the likelihood of existence of (or susceptibility to) a potential damage mechanism and may indicate expected degree of damage (e.g., expected corrosion rate). Within a given Technical Module, there may be one or more damage mechanisms.

Table 11-1—Inspection Effectiveness Categories

| Qualitative Inspection Effectiveness Category | Description                                                                                                                                                                                                              |
|-----------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                              | The inspection methods will correctly identify the true damage state in nearly every case (or 80–100% confidence).                                                                                                       |
| Usually Effective                             | The inspection methods will correctly identify the true damage state most of the time (or 60–80% confidence).                                                                                                            |
| Fairly Effective                              | The inspection methods will correctly identify the true damage state about half of the time (or 40–60% confidence).                                                                                                      |
| Poorly Effective                              | The inspection methods will provide little information to correctly identify the true damage state (or 20–40% confidence).                                                                                               |
| Ineffective                                   | The inspection method will provide no or almost no information that will correctly identify the true damage state and are considered ineffective for detecting the specific damage mechanism (less than 20% confidence). |

## **APPENDIX A—WORKBOOK FOR QUALITATIVE RISK-BASED INSPECTION ANALYSIS**

### **A.1 Overview of Qualitative Workbook**

This workbook presents the details of the qualitative RBI analysis procedure. It is formatted as fill-in-the-blank worksheets. The workbook is used to determine the Likelihood and Consequence Category for a given unit. Depending on the nature of the chemicals in a unit, the Consequence Category can be determined based on the flammable or toxic hazards for the unit. Within the workbook, flammable consequences are represented by the Damage Consequence Category, since the primary impact of a flammable event (fire or explosion) is to damage equipment. Toxic consequences fall under the Health Consequence Category, since their impact is usually limited to adverse health effects.

The workbook is subdivided as follows:

- Part A: Likelihood Category
- Part B: Damage Consequence Category
- Part C: Health Consequence Category

When determining the final Consequence Category, be sure to use the higher letter category (A is the lowest, E is the highest) derived from Part B or C.

If the unit has a number of different process fluids, the workbook exercise should be repeated for each material to derive separate risk categories for each hazardous material. The material which results in the highest level of risk (from the screening process in Section 3.2) should be considered first when the unit is evaluated for Qualitative RBI analysis.

In general, when a question presents alternates, the analyst should choose one of the alternates rather than interpolate. This will lead to more consistent results between different studies.

## Part A. Determination of Likelihood Category

|                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |   |  |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---|--|
| <b>Equipment Factor (EF)</b><br>The size of the study will affect the probability of failure of a component in the study. The qualitative risk analysis is intended for use at three different levels: <ol style="list-style-type: none"> <li>1. Unit—A full operating unit at a site is evaluated. This would typically be done to compare and prioritize operating units based on risk of operation.</li> <li>2. Section of an operating unit—an operating unit can be broken into logical (functional) sections to identify the high risk section of the unit.</li> <li>3. A system or unit operation—this is the greatest level of detail that the qualitative method is intended to address.</li> </ol> |   |  |
| To define the Equipment Factor, use the following table:<br>If a full operating unit is being evaluated, (typically greater than 150 major equipment items) EF = 15<br>If a major section of an operating unit is being evaluated, (typically 20–150 major equipment items) EF = 5<br>If a system or unit operation is being evaluated (typically 5–20 major equipment items) EF = 0<br>Select the appropriate value for EF from above.                                                                                                                                                                                                                                                                      |   |  |
| This is the overall Equipment Factor                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         | 1 |  |

## Part A. Determination of Likelihood Category

|                                                                                                                                                                                                                                                                            |    |  |
|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----|--|
| <b>Damage Factor (DF)</b><br>The damage factor is a measure of the risk associated with known damage mechanisms that are active or potentially active in the operation being evaluated. The mechanisms are prioritized based on their potential to create a serious event. |    |  |
| If there are known, active damage mechanisms that can cause corrosion cracking in carbon or low alloy steels, DF1 = 5.                                                                                                                                                     | 2  |  |
| If there is a potential for catastrophic brittle failure, including carbon steel materials due to low temperature operation or upset conditions, temper embrittlement, or materials not adequately qualified by impact testing, DF2 = 4.                                   | 3  |  |
| If there are places in the unit where mechanically thermally-induced fatigue failure has occurred and the fatigue mechanism might still be active, DF3 = 4.                                                                                                                | 4  |  |
| If there is known high temperature Hydrogen attack occurring, DF4 = 3.                                                                                                                                                                                                     | 5  |  |
| If there is known corrosion cracking of austenitic stainless steels occurring as a result of the process, DF5 = 3.                                                                                                                                                         | 6  |  |
| If localized corrosion is occurring, DF6 = 3.                                                                                                                                                                                                                              | 7  |  |
| If general corrosion is occurring, DF7 = 2.                                                                                                                                                                                                                                | 8  |  |
| If creep damage is known to be occurring in high temperature processes, including furnaces and heaters, DF8 = 1.                                                                                                                                                           | 9  |  |
| If materials degradation is known to be occurring, with such mechanisms as sigma phase formation, carburization, spheroidization, etc., DF9 = 1.                                                                                                                           | 10 |  |
| If other active damage mechanisms have been identified, DF10 = 1.                                                                                                                                                                                                          | 11 |  |
| If the potential damage mechanisms in the operating unit have not been evaluated and are not being periodically reviewed by a qualified materials engineer, DF11 = 10.                                                                                                     | 12 |  |
| The overall Damage Factor will be the sum of lines 2 through 12, up to a maximum of 20                                                                                                                                                                                     | 13 |  |

## Part A. Determination of Likelihood Category

|                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |    |  |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----|--|
| <b>Inspection Factor (IF)</b><br>The Inspection Factor is a measure of the effectiveness of the inspection program to identify the active or anticipated damage mechanisms in the unit.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |    |  |
| Step 1. Vessel Inspection—Gage the effectiveness of the vessel inspection program to find the identified failure mechanisms above. <ul style="list-style-type: none"> <li>• If the inspection program is extensive and a variety of inspection methods and monitoring are being used, IF1 = -5.</li> <li>• If there is a formal inspection program in place and some inspections are being done, but primarily visual and UT thickness readings, IF1 = -2.</li> <li>• If there is no formal inspection program in place, IF1 = 0.</li> </ul> Select appropriate IF1 from above.                                                                                                                                                                                                                                                               | 14 |  |
| Step 2. Piping Inspection—Gage the effectiveness of the piping inspection program to find the identified failure mechanisms above. <ul style="list-style-type: none"> <li>• If the inspection program is extensive, and a variety of inspection methods are being used, IF2 = -5.</li> <li>• If there is a formal inspection program in place and some inspections are being done, but primarily visual and UT thickness readings, IF2 = -2.</li> <li>• If there is no formal inspection program in place, IF2 = 0.</li> </ul> Select the appropriate value for IF2 from above                                                                                                                                                                                                                                                                | 15 |  |
| Step 3. Overall Inspection Program—How comprehensive is the inspection program design, and are the inspection results evaluated and used to modify the inspection program? <ul style="list-style-type: none"> <li>• If deterioration mechanisms have been identified for each equipment item and the inspection program is modified based on the results of the program using a competent inspector or materials engineer, IF3 = -5.</li> <li>• If the inspection program design excludes either identification of failure mechanisms or does not include critical evaluation of all inspection results, i.e., it does one or the other, but not both, IF3 = -2.</li> <li>• If the inspection program meets neither of the criteria of the previous paragraph, IF3 = 0.</li> </ul> Select the appropriate value for IF3 from the table above. | 16 |  |
| The overall Inspection Factor is the sum of lines 14 through 16, but its absolute value cannot exceed the value of the Damage Factor (line 13).                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               | 17 |  |

## Part A. Determination Of Likelihood Category

|                                                                                                                                                                                                                                                                                                                                                                                                                                |    |  |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----|--|
| <b>Condition Factor (CCF)</b><br>The Condition Factor is intended to gage the effectiveness of plant maintenance and housekeeping efforts.                                                                                                                                                                                                                                                                                     |    |  |
| Step 1. In a plant walkthrough, how would the plant housekeeping be judged (including painting and insulation maintenance programs)? <ul style="list-style-type: none"> <li>• Significantly better than industry standards, CCF1 = 0.</li> <li>• About industry standard, CCF1 = 2.</li> <li>• Significantly below industry standards, CCF1 = 5.</li> </ul> Select the appropriate value for CCF1 from above                   | 18 |  |
| Step 2. The quality of plant design and construction is: <ul style="list-style-type: none"> <li>• Significantly better than industry standards, where the owner has used more rigorous standards, CCF2 = 0.</li> <li>• About industry standard, where typical contract standards were used, CCF2 = 2.</li> <li>• Significantly below industry standards, CCF2 = 5.</li> </ul> Select the appropriate value for CCF2 from above | 19 |  |
| Step 3. In a review of the effectiveness of the plant maintenance program, including fabrication, PM programs, and QA/QC, they would be judged: <ul style="list-style-type: none"> <li>• Significantly better than industry standards, CCF3 = 0.</li> <li>• About industry standard, CCF3 = 2.</li> <li>• Significantly below industry standards, CCF3 = 5.</li> </ul> Select the appropriate value for CCF3.                  | 20 |  |
| The overall Condition Factor is the sum of 18 through 20.                                                                                                                                                                                                                                                                                                                                                                      | 21 |  |



## Part A. Determination of Likelihood Category

|                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |     |    |
|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----|----|
| <b>Process Factor (PF)</b><br>The Process Factor is a measure of the potential for abnormal operations or upset conditions to result in initiating events that could lead to a loss of containment.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |     |    |
| <b>Step 1. The number of planned or unplanned process interruptions in an average year. (This is intended for normal continuous process operations.) PF1 is taken from the following table:</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |     |    |
| Number of Interruptions                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            | PF1 |    |
| 0 to 1                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             | 0   |    |
| 2 to 4                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             | 1   |    |
| 5 to 8                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             | 3   |    |
| 9 to 12                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            | 4   |    |
| more than 12                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       | 5   |    |
| Determine appropriate PF1 from above.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |     | 22 |
| <b>Step 2. Assess the potential for exceeding key process variables in the operation being evaluated: (PF2).</b> <ul style="list-style-type: none"> <li>• If the process is extremely stable, and no combination of upset conditions is known to exist that could cause a runaway reaction or other unsafe conditions, PF2 is 0.</li> <li>• Only very unusual circumstances could cause upset conditions to escalate into an unsafe situation, PF2 is 1.</li> <li>• If upset conditions are known to exist that can result in accelerated equipment damage or other unsafe conditions, PF2 is 3.</li> <li>• If the possibility of loss of control is inherent in the process, PF2 is 5.</li> </ul> |     |    |
| Select the appropriate value for PF2 from the table above                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |     | 23 |
| <b>Step 3. Assess the potential for protection devices, such as relief devices and critical sensing elements, to be rendered inoperative as a result of plugging or fouling of the process fluid.</b> <ul style="list-style-type: none"> <li>• Clean service, no plugging potential PF3 = 0.</li> <li>• Slight fouling or plugging potential PF3 = 1.</li> <li>• Significant fouling or plugging potential PF3 = 3.</li> <li>• Protective devices have been found impaired in service PF3 = 5.</li> </ul>                                                                                                                                                                                          |     |    |
| Select the appropriate value for PF3.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |     | 24 |
| The overall Process Factor is the sum of lines 22 through 24.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |     | 25 |

## Part A. Determination of Likelihood Category

|                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |  |    |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--|----|
| <b>Mechanical Design Factor (MDF)</b><br>The Mechanical Design Factor gages certain aspects of the design of the operating equipment.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |  |    |
| <b>Step 1.</b> <ul style="list-style-type: none"> <li>If equipment can be identified that was not designed to the intent of current codes or standards, <math>MDF1 = 5</math>.<br/>           Examples: nonimpact tested carbon steel in low temperature service, materials in hydrogen service operating above the latest Nelson curve, nonstress relieved materials in a particular service (such as caustic), or plate thicknesses that would require stress relieving by current code or good practices.</li> <li>If all equipment being considered is designed and maintained to the Codes in effect at the time it was constructed, <math>MDF1 = 2</math>.</li> <li>If all equipment being considered is designed and maintained to current codes, <math>MDF1 = 0</math>.</li> </ul> |  |    |
| Enter the appropriate value from the statements above. This is $MDF1$ .                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |  | 26 |
| <b>Step 2.</b> <ul style="list-style-type: none"> <li>If the process being evaluated is unusual or unique or any of the process design conditions are extreme, <math>MDF2 = 5</math>.<br/>           Extreme Design Conditions are considered to be:           <ul style="list-style-type: none"> <li>a. Pressure exceeding 10,000 psi.</li> <li>b. Temperature exceeding 1500 °F.</li> <li>c. Corrosive conditions requiring high alloy materials (more exotic than 316 stainless steel).</li> </ul> </li> <li>If the process is common, with normal design conditions, <math>MDF2 = 0</math>.</li> </ul>                                                                                                                                                                                 |  |    |
| Select the appropriate value from the table above. This is $MDF2$ .                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |  | 27 |
| Step 3. Add lines 26 and 27. This is the Mechanical Design Factor.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |  | 28 |

## Part A. Determination of Likelihood Category

| <b>Likelihood Category</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                     |                     |                   |                     |      |   |       |   |       |   |       |   |       |   |  |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------|-------------------|---------------------|------|---|-------|---|-------|---|-------|---|-------|---|--|
| <b>Step 1. Determine the Likelihood Factor.</b> The Likelihood Factor is the sum of the previously determined factors.<br>Add lines 1, 13, 17, 21, 25, and 28. This is the Likelihood Factor.                                                                                                                                                                                                                                                                                  |                     | 29                |                     |      |   |       |   |       |   |       |   |       |   |  |
| <b>Step 2. The Likelihood Category is determined from the Likelihood Factor (line 29 above) using the following table:</b> <table border="1" style="margin-left: 20px;"> <thead> <tr> <th>Likelihood Factor</th> <th>Likelihood Category</th> </tr> </thead> <tbody> <tr> <td>0-15</td> <td>1</td> </tr> <tr> <td>16-25</td> <td>2</td> </tr> <tr> <td>26-35</td> <td>3</td> </tr> <tr> <td>36-50</td> <td>4</td> </tr> <tr> <td>51-75</td> <td>5</td> </tr> </tbody> </table> |                     | Likelihood Factor | Likelihood Category | 0-15 | 1 | 16-25 | 2 | 26-35 | 3 | 36-50 | 4 | 51-75 | 5 |  |
| Likelihood Factor                                                                                                                                                                                                                                                                                                                                                                                                                                                              | Likelihood Category |                   |                     |      |   |       |   |       |   |       |   |       |   |  |
| 0-15                                                                                                                                                                                                                                                                                                                                                                                                                                                                           | 1                   |                   |                     |      |   |       |   |       |   |       |   |       |   |  |
| 16-25                                                                                                                                                                                                                                                                                                                                                                                                                                                                          | 2                   |                   |                     |      |   |       |   |       |   |       |   |       |   |  |
| 26-35                                                                                                                                                                                                                                                                                                                                                                                                                                                                          | 3                   |                   |                     |      |   |       |   |       |   |       |   |       |   |  |
| 36-50                                                                                                                                                                                                                                                                                                                                                                                                                                                                          | 4                   |                   |                     |      |   |       |   |       |   |       |   |       |   |  |
| 51-75                                                                                                                                                                                                                                                                                                                                                                                                                                                                          | 5                   |                   |                     |      |   |       |   |       |   |       |   |       |   |  |
| Enter the Likelihood Category.                                                                                                                                                                                                                                                                                                                                                                                                                                                 |                     | 30                |                     |      |   |       |   |       |   |       |   |       |   |  |

## Part B. Determination of Damage Consequence Category

This section is to be used for flammable materials, if only toxic chemicals are present, go directly to Part C.

|                                                                                                                                                                                                                                                                                     |   |                             |    |    |
|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---|-----------------------------|----|----|
| <b>Chemical Factor (CF)</b>                                                                                                                                                                                                                                                         |   |                             |    |    |
| The Chemical Factor is a measure of a chemical's inherent tendency to ignite. The answers to this section should be based on the predominate or representative material in the stream. Separate analyses should be performed if the unit has a number of different process streams. |   |                             |    |    |
| Step 1. Determine a "Flash Factor," using the NFPA Flammable Hazard Rating (the RED diamond on the NFPA Hazard Identification System sign).                                                                                                                                         |   |                             |    |    |
| Enter the NFPA Flammable Hazard Rating.                                                                                                                                                                                                                                             |   |                             |    | 31 |
| Step 2. Determine a "Reactivity Factor," using the NFPA Reactivity Hazard Rating System (the YELLOW diamond on the NFPA Hazard Identification System sign).                                                                                                                         |   |                             |    |    |
| Enter the NFPA Reactivity Hazard Rating.                                                                                                                                                                                                                                            |   |                             |    | 32 |
| Step 3. Determine "Chemical Factor."                                                                                                                                                                                                                                                |   |                             |    |    |
|                                                                                                                                                                                                                                                                                     |   | Reactivity Factor (line 32) |    |    |
|                                                                                                                                                                                                                                                                                     |   | 1                           | 2  | 3  |
|                                                                                                                                                                                                                                                                                     |   | 7                           | 9  | 12 |
| Flash Factor                                                                                                                                                                                                                                                                        | 2 | 10                          | 12 | 15 |
| (line 31)                                                                                                                                                                                                                                                                           | 3 | 12                          | 15 | 20 |
|                                                                                                                                                                                                                                                                                     | 4 | 13                          | 15 | 25 |
| Select the Chemical Factor from the chart above.                                                                                                                                                                                                                                    |   |                             |    | 33 |

## Part B. Determination of Damage Consequence Category

|                                                                                                                                                                                     |                        |
|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------|
| <b>Quantity Factor (QF)</b>                                                                                                                                                         |                        |
| The Quantity Factor represents the largest amount of material which could be released from a unit in a single scenario.                                                             |                        |
| The Quantity Factor is taken directly from the chart below. For amount of material released, use the largest amount of flammable inventory that can be lost in a single leak event. |                        |
| <u>Material Released</u>                                                                                                                                                            | <u>Quantity Factor</u> |
| <1,000 pounds                                                                                                                                                                       | 15                     |
| 1K-2K pounds                                                                                                                                                                        | 20                     |
| 2K-10K pounds                                                                                                                                                                       | 25                     |
| 10K-30K pounds                                                                                                                                                                      | 28                     |
| 30K-80K pounds                                                                                                                                                                      | 31                     |
| 80K-200K pounds                                                                                                                                                                     | 34                     |
| 200K-700K pounds                                                                                                                                                                    | 37                     |
| 700K-1 million                                                                                                                                                                      | 39                     |
| 1-2 million                                                                                                                                                                         | 41                     |
| 2-10 million                                                                                                                                                                        | 45                     |
| > million                                                                                                                                                                           | 50                     |
| Enter the appropriate value from the table above. This is the Quantity Factor.                                                                                                      |                        |
| 34                                                                                                                                                                                  |                        |
| <b>State Factor</b>                                                                                                                                                                 |                        |
| The State Factor is dependent on the normal boiling point of the fluid, an indication of the fluid's tendency to vaporize and disperse when released into the environment.          |                        |
| Select a State Factor based on the normal (atmospheric pressure) boiling temperature ( $T_b$ ) in degrees Fahrenheit.                                                               |                        |
| <u><math>T_b</math> (°F)</u>                                                                                                                                                        | <u>State Factor</u>    |
| below -100                                                                                                                                                                          | 8                      |
| -100 to 100                                                                                                                                                                         | 6                      |
| 100 to 250                                                                                                                                                                          | 5                      |
| 250 to 400                                                                                                                                                                          | 1                      |
| above 400                                                                                                                                                                           | -3                     |
| Select the appropriate value from the table above. This is the State Factor.                                                                                                        |                        |
| 35                                                                                                                                                                                  |                        |

## Part B. Determination of Damage Consequence Category

|                                                                                                                                                                                                                                                                                                |                  |    |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------|----|
| <b>Autoignition Factor (AF)</b><br>The Autoignition Factor is a penalty applied to fluid that is processed at a temperature above its autoignition temperature.                                                                                                                                |                  |    |
| If a fluid is processed below its AIT, enter -10                                                                                                                                                                                                                                               |                  |    |
| If the fluid is processed above its AIT, use the following table to determine AF, based on the normal boiling point of the fluid (in degrees Fahrenheit).                                                                                                                                      |                  |    |
| <u>T<sub>b</sub> (°F)</u>                                                                                                                                                                                                                                                                      | <u>AF Factor</u> |    |
| below 0                                                                                                                                                                                                                                                                                        | 3                |    |
| 0 to 300                                                                                                                                                                                                                                                                                       | 7                |    |
| above 300                                                                                                                                                                                                                                                                                      | 13               |    |
| Enter the appropriate value from the table above. This is the Autoignition Factor.                                                                                                                                                                                                             |                  | 36 |
| <b>Pressure Factor (PRF)</b><br>The Pressure Factor represents the fluid's tendency to be released quickly, resulting in a greater chance of instantaneous-type effects.                                                                                                                       |                  |    |
| <ul style="list-style-type: none"> <li>• If the fluid is a liquid inside the equipment, enter -10.</li> <li>• If the fluid is a gas inside the equipment, and at a pressure of greater than 150 psig, enter -10.</li> <li>• If neither of the above conditions are true, enter -15.</li> </ul> |                  |    |
| Select the appropriate value from the table above. This is the Pressure Factor.                                                                                                                                                                                                                |                  | 37 |

## Part B. Determination of Damage Consequence Category

|                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |    |  |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----|--|
| <b>Credit Factor (CF)</b><br>The Credit Factor is the product of several subfactors of engineered systems in place which can reduce the damage from an event.                                                                                                                                                                                                                                                                                                                           |    |  |
| If there is gas detection in place which would detect 50% or more of incipient leaks, enter -1, otherwise, enter 0.                                                                                                                                                                                                                                                                                                                                                                     | 38 |  |
| If process equipment is normally operated under an inert atmosphere, enter -1, otherwise enter 0.                                                                                                                                                                                                                                                                                                                                                                                       | 39 |  |
| If fire-fighting systems are "secure" in the event of a major incident (e.g. fire water system will remain intact in the event of an explosion), enter -1, otherwise enter 0.                                                                                                                                                                                                                                                                                                           | 40 |  |
| If the isolation capability of the equipment in this area can be controlled remotely, AND: <ul style="list-style-type: none"> <li>• the isolation and associated instrumentation is protected from fires and explosions, then enter -1,</li> <li>• OR, if the isolation and associated instrumentation is protected from fires only, enter -1,</li> <li>• OR, if there is no protection for the isolation capability from fires or explosions, enter -1,</li> </ul> otherwise, enter 0. | 41 |  |
| If there are blast walls around the most critical (typically highest pressure) equipment, enter -1, otherwise enter 0.                                                                                                                                                                                                                                                                                                                                                                  | 42 |  |
| If there is a dump, drain, or blowdown system which will deinventory 75% or more of the material in 5 minutes or less, with 90% reliability, enter -1, otherwise enter 0.                                                                                                                                                                                                                                                                                                               | 43 |  |
| If there is fireproofing in place on both structures and cables, enter -1, if there is fireproofing on either structures or cables, enter 0.95, otherwise enter 0.                                                                                                                                                                                                                                                                                                                      | 44 |  |
| If there is a fire water supply which will last at least 4 hours, enter -1, otherwise enter 0.                                                                                                                                                                                                                                                                                                                                                                                          | 45 |  |
| If there is a fixed foam system in place, enter -1, otherwise enter 0.                                                                                                                                                                                                                                                                                                                                                                                                                  | 46 |  |
| If there are firewater monitors which can reach all areas of the affected unit, enter -1, otherwise enter 0.                                                                                                                                                                                                                                                                                                                                                                            | 47 |  |
| Add lines 38 through 47. This is the Credit Factor.                                                                                                                                                                                                                                                                                                                                                                                                                                     | 48 |  |

## Part B. Determination of Damage Consequence Category

| Damage Consequence Category                                                                                                               |                                |    |
|-------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------|----|
| Step 1. Determine the Damage Consequence Factor.<br>Add lines 33, 34, 35, 36, 37, and 48 together, this is the Damage Consequence Factor. |                                | 49 |
| Step 2. The Damage Consequence Factor (line 49) is then converted into a Damage Consequence Category based on the table below:            |                                |    |
| Consequence<br><u>Factor</u>                                                                                                              | Consequence<br><u>Category</u> |    |
| 0-19                                                                                                                                      | A                              |    |
| 20-34                                                                                                                                     | B                              |    |
| 35-49                                                                                                                                     | C                              |    |
| 50-79                                                                                                                                     | D                              |    |
| > 70                                                                                                                                      | E                              |    |
| Enter the Damage Consequence Category.                                                                                                    |                                | 50 |

## Part C. Health Consequence Category

If the process fluid of concern has only flammable consequences, skip Part C.

|                                                                                                                                                                                               |                               |    |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------|----|
| <b>Toxic Quantity Factor (TQF).</b>                                                                                                                                                           |                               |    |
| The Toxic Quantity Factor is a measure of both the quantity of the chemical and its toxicity.                                                                                                 |                               |    |
| Step 1. The Toxic Quantity Factor is taken directly from the chart below. For amount of chemical released, use the largest amount of toxic inventory that can be lost in a single leak event. |                               |    |
| <u>Material Released</u>                                                                                                                                                                      | <u>Quantity Factor</u>        |    |
| <1,000 pounds                                                                                                                                                                                 | 15                            |    |
| 1K-10K pounds                                                                                                                                                                                 | 20                            |    |
| 10K-100K pounds                                                                                                                                                                               | 27                            |    |
| >1 million pounds                                                                                                                                                                             | 35                            |    |
| Enter the Factor from the chart above, this is TQF1.                                                                                                                                          |                               | 51 |
| Step 2. Estimate the Toxicity Factor (TQF2) from the chart below, based on the BLUE diamond in the NFPA Hazard Identification System.                                                         |                               |    |
| <u>NFPA N<sub>h</sub></u>                                                                                                                                                                     | <u>Toxicity Factor (TOF2)</u> |    |
| 1                                                                                                                                                                                             | -20                           |    |
| 2                                                                                                                                                                                             | -10                           |    |
| 3                                                                                                                                                                                             | 0                             |    |
| 4                                                                                                                                                                                             | 20                            |    |
| Enter the Toxicity Factor.                                                                                                                                                                    |                               | 52 |
| Step 3. Add lines 51 and 52. This is the Toxic Quantity Factor.                                                                                                                               |                               | 53 |

## Part C. Health Consequence Category

|                                                                                                                                                                                                                                                                                                                                                                                                  |         |                |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------|----------------|
| <b>Dispersibility Factor (DIF)</b>                                                                                                                                                                                                                                                                                                                                                               |         |                |
| The Dispersibility Factor is a measure of the ability of the material to disperse, given typical process conditions.                                                                                                                                                                                                                                                                             |         |                |
| Step 1. Determine the Dispersibility Factor from the table below.                                                                                                                                                                                                                                                                                                                                |         |                |
| (F)                                                                                                                                                                                                                                                                                                                                                                                              | Factor  | Dispersibility |
|                                                                                                                                                                                                                                                                                                                                                                                                  | < 30    | 1              |
|                                                                                                                                                                                                                                                                                                                                                                                                  | 30-80   | 0.5            |
|                                                                                                                                                                                                                                                                                                                                                                                                  | 80-140  | 0.3            |
|                                                                                                                                                                                                                                                                                                                                                                                                  | 140-200 | 0.1            |
|                                                                                                                                                                                                                                                                                                                                                                                                  | 200-300 | 0.05           |
|                                                                                                                                                                                                                                                                                                                                                                                                  | > 300   | 0.03           |
| Enter the Dispersibility Factor                                                                                                                                                                                                                                                                                                                                                                  |         | 54             |
| <b>Credit Factor (CRF)</b>                                                                                                                                                                                                                                                                                                                                                                       |         |                |
| The Credit Factor accounts for safety features that reduce the consequences of a toxic release by detection, isolation and mitigation.                                                                                                                                                                                                                                                           |         |                |
| Step 1.                                                                                                                                                                                                                                                                                                                                                                                          |         |                |
| <ul style="list-style-type: none"> <li>If there are detectors in place for the process fluid of interest that would detect 50% or more of incipient leaks, enter -1,</li> <li>Otherwise enter 0.</li> </ul>                                                                                                                                                                                      |         | 55             |
| Step 2.                                                                                                                                                                                                                                                                                                                                                                                          |         |                |
| <ul style="list-style-type: none"> <li>If major vessels containing this material can be isolated automatically, and isolation is initiated from a high reading from a toxic material detector, enter -1,</li> <li>OR, if the isolation is remote with a manual initiation, enter -5,</li> <li>OR, if the isolation is manually operated only, enter -25,</li> <li>Otherwise, enter 0.</li> </ul> |         | 56             |
| Step 3.                                                                                                                                                                                                                                                                                                                                                                                          |         |                |
| <ul style="list-style-type: none"> <li>If there is a system in place (water curtains, etc.) that has proven to be effective in mitigating at least 90% of the fluid, enter -5,</li> <li>Otherwise enter 1.0.</li> </ul>                                                                                                                                                                          |         | 57             |
| Step 4. Add lines 55 through 57. This is the Credit Factor.                                                                                                                                                                                                                                                                                                                                      |         | 58             |

## Part C. Health Consequence Category

## Population Factor (PPF)

The Population Factor is a measure of the potential number of people that can be affected by the toxic event.

Estimate the Population Factor from the chart below. This is based on the number of people, on the average, within one-quarter mile of the release point. Consider both onsite and offsite populations. Within the plant boundaries, use daytime population counts.

| Number of People Within<br>One-Quarter Mile Radius | Population<br>Factor |
|----------------------------------------------------|----------------------|
| < 10                                               | 0                    |
| 10-100                                             | 7                    |
| 100-1000                                           | 15                   |
| 1000-10,000                                        | 20                   |

Enter the Population Factor.

59

## Health Consequence Category

Step 1. Add lines 53, 54, and 59 together. This is the Health Consequence Factor

60

Step 2. The Health Consequence Factor (line 60) is then placed in a Health Consequence Category, as follows:

| Health Consequence<br>Factor | Health Consequence<br>Category |
|------------------------------|--------------------------------|
| < 10                         | A                              |
| 10-19                        | B                              |
| 20-29                        | C                              |
| 30-39                        | D                              |
| > 40                         | E                              |

Enter the Health Consequence Category.

61

## Overall Consequence Category.

Choose the highest letter from line 50 or 61 (A is lowest, E is highest). This is the Overall Consequence Category.

## APPENDIX B—WORKBOOK FOR SEMI-QUANTITATIVE RISK-BASED INSPECTION ANALYSIS

### B.1 Introduction

After the completion of the first RBI pilot project, a scaled down approach to RBI analysis was developed to provide most of the benefit but not require as much input. It was also desired to present the results in a simplified manner, e.g., a 5 x 5 matrix showing Likelihood vs. Consequence in which the values are presented as categories. Such a 5 x 5 matrix is shown in Figure B-1. The scaled down approach was referred to as a "Level II" approach; the qualitative approach (See Section 5) is "Level I"; and an approach using all of the methods of the BRD is "Level III".

### B.2 Consequence Analysis

For Level II RBI, the consequence model is essentially the same as is outlined in Section 7. One major simplification is in the determination of inventory amounts. In the pilot project, a large amount of time and effort was expended in determination of inventory amounts. For the Level II approach, to simplify this process, inventories may be estimated on an order of magnitude basis using the following guidelines:

The inventories can be selected from one of five "order of magnitude" categories as shown in Table B-1.

Table B-1—Inventory Category Ranges

| Category | Range                        | Value Used In Calculations |
|----------|------------------------------|----------------------------|
| A        | 100 to 1,000 lbs.            | 500                        |
| B        | 1,000 to 10,000 lbs.         | 5,000                      |
| C        | 10,000 to 100,000 lbs.       | 50,000                     |
| D        | 100,000 to 1,000,000 lbs.    | 500,000                    |
| E        | 1,000,000 to 10,000,000 lbs. | 5,000,000                  |

The user can select the category based on judgmental evaluation for each category as outlined in Table B-2:

Table B-2—Description of Inventory Categories

| Category | Qualitative Description                                                                                                     |
|----------|-----------------------------------------------------------------------------------------------------------------------------|
| A        | The release will result in less than total deinventory of the equipment item being evaluated.                               |
| B        | The release will result in total deinventory of the equipment item being evaluated.                                         |
| C        | The release will result in total deinventory of the equipment item being evaluated, plus one to ten other equipment items.  |
| D        | The release will result in total deinventory of the equipment item being evaluated, plus ten or more other equipment items. |
| E        | The release will result in total deinventory of the unit.                                                                   |

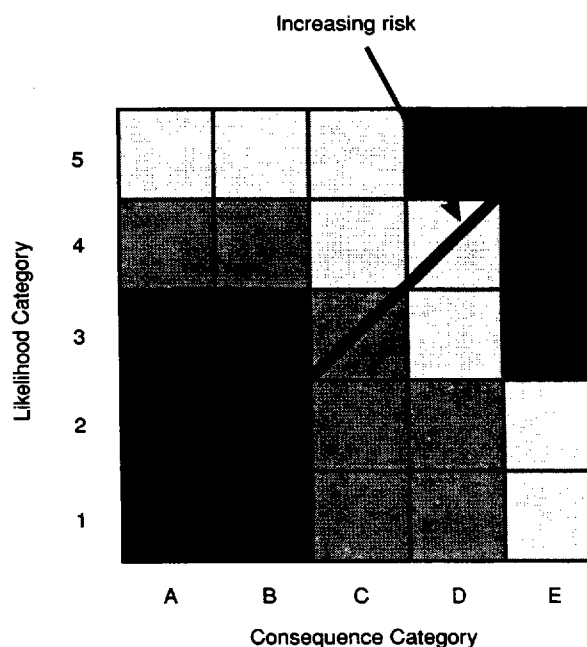


Figure B-1—Level II Risk Matrix

The person performing the analysis still has the option to use any value for the inventory. For example, if the inventory has been calculated, this value may be entered.

The consequence area is calculated for each hole size exactly as outlined in Section 7. To calculate a single overall consequence of failure for each equipment item, a "Likelihood Weighted" average area is calculated. This is done by first multiplying the consequence area for each hole size by the ratio of the "generic" frequency for that hole size to the sum of the "generic" frequencies for all hole sizes. (See Equation B-1.)

$$\frac{FREQ_{n=4}}{FREQ_{n=1}} \times AREAn \quad (B-1)$$

This ratio determines the "weight" to be given to the calculated area for each hole size depending on the relative likelihood of the hole relative to other holes. In this approach, the value of each "generic" frequency does not matter, only the relative values of each vs. the others. The weighted area thus calculated for each hole size is then summed to produce a single consequence area value. (See Equation B-2) This value can be considered to be the most likely affected area if many events were observed that follow the distribution of generic hole sizes used.



LIKELIHOOD WEIGHTED AVERAGE AREA =

$$\sum_{n=1}^{n=4} AREA_n \times \frac{FREQ_n}{\sum_{n=1}^{n=4} FREQ_n} \quad (B-2)$$

The conversion of the likelihood weighted average area to a consequence category is accomplished through a simple assignment of categories to area values. It is possible, depending on the assignments chosen, to have an area associated with any category, according to the needs of the study. However, it was the consensus opinion of the API RBI Sponsor Group that refineries should all be compared using the same assignment of areas to categories. A simple order of magnitude assignment is illustrated in Table B-3.

Table B-3—Consequence Area Categories

| Consequence Category | Likelihood Weighted Average Area |
|----------------------|----------------------------------|
| A                    | < 10 ft <sup>2</sup>             |
| B                    | 10 – 100 ft <sup>2</sup>         |
| C                    | 100 – 1,000 ft <sup>2</sup>      |
| D                    | 1,000 – 10,000 ft <sup>2</sup>   |
| E                    | > 10,000 ft <sup>2</sup>         |

In keeping with the philosophy of Level II being a simplified approach for the purposes of ranking equipment by risk, business interruption and environmental consequences are not included in the approach.

### B.3 Likelihood Analysis

One major observation of the pilot study was that in many cases, the technical module subfactors far outweighed all of the other subfactors combined. The technical module subfactors can range as high as 1,000 or more, while the other subfactors are relatively small (< 10). In addition, the other subfactors (except for the mechanical subfactor) tend to be constant across a plant or unit, and thus do not provide any discrimination between equipment items in any given plant or unit. As such, these subfactors can be used for comparisons between different sites, but do not aid the formation of an inspection plan based on risk. The “other” subfactors are listed for reference:

Based on these observations, it was decided that the likelihood would only be determined by the technical module subfactor. This is the only subfactor that is directly affected by inspection and that will form the basis for an inspection plan.

The conversion of the technical module subfactor to a likelihood category is accomplished through a simple assignment

Table B-4—Variability of Technical Module Subfactors

| Subfactor                   | Variability                    |
|-----------------------------|--------------------------------|
| • Universal Subfactor       |                                |
| – Plant Condition           | Constant for Plant             |
| – Cold Weather              | Constant for Plant             |
| – Seismic Activity          | Constant for Plant             |
| • Mechanical Subfactor      |                                |
| – Equipment Complexity      | Varies by equipment            |
| – Construction Code         | Varies by equipment            |
| – Life Cycle                | Varies by equipment            |
| – Safety Factors            | Varies by equipment            |
| – Vibration Monitoring      | Usually constant within a unit |
| • Process Subfactor         |                                |
| – Continuity                | Constant for a Unit            |
| – Stability                 | Constant for a Unit            |
| – Relief Valves             | Constant for a Unit            |
| • Process Safety Management | Constant for a Unit or Plant   |

Table B-5—Technical Module Subfactor Conversion

| Likelihood Category | Technical Module Subfactor |
|---------------------|----------------------------|
| 1                   | < 1                        |
| 2                   | 1 – 10                     |
| 3                   | 10 – 100                   |
| 4                   | 100 – 1,000                |
| 5                   | > 1,000                    |

of categories to subfactor values. A simple order of magnitude assignment was chosen and is illustrated in Table B-5.

### B.4 Risk Analysis

The Risk Analysis for the Level II approach is a straightforward assignment of likelihood and consequence to their appropriate categories and placing them in the 5 x 5 matrix. Different areas of the matrix are shaded to illustrate “High”, “Medium High”, “Medium”, and “Low” categories of Risk. These assignments are shown in Figure B-2.

Note that the risk assignments are skewed to assign higher risks to higher consequence events. This is commonly done in forming plots of risk to illustrate a stronger aversion to high consequence events vs. low consequence events.

|                     |   |     |   |           |   |   |                      |
|---------------------|---|-----|---|-----------|---|---|----------------------|
| Likelihood Category | 5 |     |   |           |   |   | High                 |
|                     | 4 |     |   | Med. High |   |   |                      |
|                     | 3 |     |   |           |   |   |                      |
|                     | 2 |     |   | Medium    |   |   |                      |
|                     | 1 | Low |   |           |   |   |                      |
|                     |   | A   | B | C         | D | E | Consequence Category |

Figure B-2—Level II Qualitative Risk Matrix

## B.5 Workbook for Level II Approach

This workbook is intended to be used as a worksheet in conjunction with the Base Resource Document (BRD)

Level II approach to RBI. It captures the relevant information and calculations outlined in Appendix A and guides the user through each step required to categorize likelihood, consequence, and risk. The workbook is designed for use on a single piece of equipment. It calculates two different consequences covered by Level II RBI:

- Flammable Consequences
- Toxic Consequences

The results for flammable and toxic consequences are reported as a category.

In order to perform the quantitative RBI calculations, some characteristics of the release need to be defined. Part A of this workbook covers these initial calculations to determine release rate, type, durations, etc.

A likelihood analysis (Part B) is then carried out to obtain likelihood categories for the equipment. As outlined in Appendix I, the likelihood category is determined by the technical module subfactor.

Risk is evaluated last (Part D), by placement of the likelihood category and the consequence category in the Risk Matrix. The above process, repeated for all pieces of equipment within a unit or plant, will produce risk measures that can help prioritize the equipment based on its potential risk.

|                                                                                                                                                            |                                                                                                                                                                                        |                          |              |                                |
|------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------|--------------|--------------------------------|
| Operating Unit:                                                                                                                                            |                                                                                                                                                                                        |                          |              |                                |
| Equipment No:                                                                                                                                              |                                                                                                                                                                                        |                          |              |                                |
| Description:                                                                                                                                               |                                                                                                                                                                                        |                          |              |                                |
| <b>Part A RELEASE RATE CALCULATION</b><br>Estimation of release rates for different hole sizes and release types and durations for each of the hole sizes. |                                                                                                                                                                                        |                          |              |                                |
| <b>Step I</b>                                                                                                                                              | <b>CALCULATE RELEASE RATE</b>                                                                                                                                                          |                          |              |                                |
| 1.                                                                                                                                                         | Enter representative material contained in equipment being evaluated. (Table 7.1 in Section 7.1)                                                                                       |                          |              |                                |
| 2.                                                                                                                                                         | Enter the inventory category for the equipment using the guidelines in section 2 of Appendix VIII.                                                                                     |                          |              |                                |
| 2a.                                                                                                                                                        | Enter the inventory value as the midpoint of the range, or as a calculated value. (See Appendix VIII, Table B-1).                                                                      | lbs.                     |              |                                |
| 3.                                                                                                                                                         | Use Table 7.4 to enter detection rating applicable to the detection systems present in the area.                                                                                       |                          |              |                                |
| 4.                                                                                                                                                         | Use Table 7.4 to enter isolation rating applicable to the isolation systems present in the area.                                                                                       |                          |              |                                |
| 5.                                                                                                                                                         | Use Table 7.5 to estimate leak duration based on detection and isolation systems.                                                                                                      | $\frac{1}{4}$ in.<br>min | 1 in.<br>min | 4 in.<br>min<br>Rupture<br>min |
| 6.                                                                                                                                                         | Enter operating pressure                                                                                                                                                               | psia                     |              |                                |
| 7.                                                                                                                                                         | Circle gas or liquid, depending on the phase of the fluid in the equipment. If liquid, skip to Line 15.                                                                                | Gas                      |              | Liquid                         |
| <b>GAS RELEASE RATE</b>                                                                                                                                    |                                                                                                                                                                                        |                          |              |                                |
| 8.                                                                                                                                                         | Enter the process temperature                                                                                                                                                          | °F                       |              |                                |
| 9.                                                                                                                                                         | From standard tables of fluid properties, enter the heat capacity ( $C_p$ ) of the gas at temperature given in Line 8.                                                                 | BTU/lb-mol °F            |              |                                |
| 10.                                                                                                                                                        | Calculate and enter $K[K = C_p \Pi (C_p - R)]$ where R is ideal gas constant. (1.987 BTU/lb-mol °F)                                                                                    |                          |              |                                |
| 11.                                                                                                                                                        | Calculate and enter transition pressure ( $P_{trans}$ ), using Equation 7.2 in Section 7.4.                                                                                            | psia                     |              |                                |
| 12.                                                                                                                                                        | Is fluid pressure inside the equipment greater than transition pressure (Line 6 > Line 11)?<br>If yes, circle "sonic," go to Line 13.<br>If no, circle "subsonic" and skip to Line 14. | Sonic                    |              | Subsonic                       |
|                                                                                                                                                            | <b>HOLE SIZES →</b>                                                                                                                                                                    | $\frac{1}{4}$ in.        | 1 in.        | 4 in.<br>Rupture               |
| 13.                                                                                                                                                        | Use sonic Equation 7.3 in Section 7.4 to calculate release rate for each of the listed hole sizes and enter rate. Skip to Line 16.                                                     | lb/sec                   | lb/sec       | lb/sec                         |
| 14.                                                                                                                                                        | Use subsonic Equation 7.4 in Section 7.4 to calculate release rate for each of the listed hole sizes and enter rate. Skip to Line 16.                                                  | lb/sec                   | lb/sec       | lb/sec                         |

| LIQUID RELEASE RATE                                      |                                                                                                                                                                                                                                                                                     |              |              |              |              |
|----------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------|--------------|--------------|--------------|
| 15.                                                      | Use liquid release Equation 7.1 in Section 7.4 to calculate release rate. Enter rate. Go to Line 16.                                                                                                                                                                                | lb/sec       | lb/sec       | lb/sec       | lb/sec       |
| <b>Step II DETERMINE RELEASE TYPE FOR EACH HOLE SIZE</b> |                                                                                                                                                                                                                                                                                     |              |              |              |              |
| 16.                                                      | Divide maximum permissible released inventory by the appropriate release rate = Line 2 ÷ (Line 13, 14 or 15). Divide by 60 to get minutes. Enter value. This is the time required to deinventory, based on initial flow rates.                                                      | min          | min          | min          | min          |
| 17.                                                      | Is flow rate (lines 13, 14 or 15) times three minutes > 10,000 lbs.? If the answer is yes, circle "inst" for instantaneous. Otherwise, circle "cont" for continuous. Note that 1/4 in. hole sizes are always "cont".                                                                | inst<br>cont | inst<br>cont | inst<br>cont | inst<br>cont |
| <b>DETERMINATION OF PHASE AFTER RELEASE</b>              |                                                                                                                                                                                                                                                                                     |              |              |              |              |
| 18.                                                      | Enter the boiling point of the fluid at atmospheric pressure, T <sub>NBP</sub>                                                                                                                                                                                                      | °F           |              |              |              |
| 19.                                                      | Use Table 7.3 to determine the phase of the fluid after the release. Enter the phase                                                                                                                                                                                                |              |              |              |              |
| 20.                                                      | Enter the initials of the circled terms in Lines 17 and Line 19. This is the release type (i.e., IL for instantaneous liquid, etc.)                                                                                                                                                 |              |              |              |              |
| 21.                                                      | Look at Line 5 and at Line 16. For each hole size, enter the lesser of the two. This is the release duration. For instantaneous, the duration is assumed to be 0. (Release duration at Line 5 is based on detection/isolation and at Line 16 is based on inventory ÷ release rate.) | min          | min          | min          | min          |
| <b>DETERMINATION OF INSTANTANEOUS RELEASE MASS</b>       |                                                                                                                                                                                                                                                                                     |              |              |              |              |
| 22.                                                      | Enter the inventory of the equipment being evaluated from Line 2a. This is the instantaneous release mass.                                                                                                                                                                          | lbs.         |              |              |              |

**Part B LIKELIHOOD ANALYSIS**

**Likelihood Analysis is the product of several factors that can indicate likelihood of equipment failure.**

**Step I TECHNICAL MODULES SUBFACTOR (See Section 8.3.1)**

Screen to identify damage mechanisms. Use appropriate damage mechanism technical module (see Appendix VIII) to determine individual factors.

If no damage mechanisms are identified, then enter -2 as technical module subfactor (Line 11).

**1. Identified damage mechanisms**

1a. Thinning/Corrosion (Y/N)

1b. HTHA (Y/N)

1c. SCC (Y/N)

Note: Items 2 through 7 are for recording certain basic information applicable to the Technical Modules. Not all items are required by each module, and not all data required by each Technical Module are presented below.

1a

1b

1c

2. Age of equipment in current service

2A. Estimated/measured corrosion rate

2B. Nelson Curve Temperature

2C. SCC Crack Size or Susceptibility

3. Calculate left column of Technical Module table

4. Determine inspection equivalents (H, U, F, P, I)

4A. Number of Inspections

5. Technical module subfactor from table

6. Correction for overdesign

7. Correction for highly reliable damage rate data

8. Corrected technical module subfactor

9. Combined technical module subfactor

10. Likelihood category from Table B-6 of Appendix VIII

| <b>Part C.1 FLAMMABLE CONSEQUENCE CALCULATIONS</b>                                                                        |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
|---------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------|-----------------|-----------------|
| <b>Estimation of the flammable consequences area for equipment and personnel due to an ignited release of hydrocarbon</b> |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| <b>REPRESENTATIVE MATERIAL</b>                                                                                            |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 1.                                                                                                                        | Copy representative material (Line 1 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                                                                                                                                |                 |                 |                 |
| <b>HOLE SIZES →</b>                                                                                                       |                                                                                                                                                                                                                                                                                                                                                                      | 1/4 in.         | 1 in.           | 4 in.           |
|                                                                                                                           |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 | Rupture         |
| <b>RELEASE TYPE</b>                                                                                                       |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 2.                                                                                                                        | Copy release type (Line 23 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                                                                                                                                          |                 |                 |                 |
| <b>RELEASE RATE OR MASS</b>                                                                                               |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 3.                                                                                                                        | Copy the release rate or mass (Line 13 or 14 or 15 or 22 from Release Rate Calculation Workbook, Part A), depending on the type of release                                                                                                                                                                                                                           | lb or lb/min    | lb or lb/min    | lb or lb/min    |
| <b>DETECTION RATING</b>                                                                                                   |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 4.                                                                                                                        | Copy Line 3 from Release Rate Worksheet (detection rating applicable to the detection systems present in the area).                                                                                                                                                                                                                                                  |                 |                 |                 |
| <b>ISOLATION RATING</b>                                                                                                   |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 5.                                                                                                                        | Copy Line 4 from Release Rate Worksheet (isolation rating applicable to the isolation systems present in the area).                                                                                                                                                                                                                                                  |                 |                 |                 |
| <b>ADJUSTMENTS FOR FLAMMABLE EVENT MITIGATION</b>                                                                         |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 6.                                                                                                                        | Look at Table 7.14 in Section 7.8 to adjust release rates or mass based on Line 4 and 5 above. Enter adjusted release rate or mass. For mitigation systems that reduce consequence area (firewater deluge system, monitors, or foam spray system), make adjustment on Line 9.                                                                                        | lb or lb/min    | lb or lb/min    | lb or lb/min    |
| <b>EQUIPMENT DAMAGE AREA</b>                                                                                              |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 7.                                                                                                                        | Look at Equipment Damage equations in Consequence Equation Tables 7.10 to 7.13 and replace "x" by adjusted release rate or mass (Line 6) in appropriate equations. (Use the information in Lines 1, 2, and 3 to select the correct equation) Use Table 7.12 or 7.13 if the fluid is at 80°F above its auto ignition temperature, otherwise use Table 7.10 or 7.11.   | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| <b>POTENTIAL FATALITIES AREAS</b>                                                                                         |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 8.                                                                                                                        | Look at Area of Potential Fatalities in Consequence Equation Tables 7.10 to 7.13 and replace "x" by adjusted release rate or mass (Line 6) in appropriate equations. (Use the information in Lines 1, 2, and 3 to select the correct equation) Use Table 7.12 or 7.13 if the fluid is at 80°F above its auto ignition temperature, otherwise use Table 7.10 or 7.11. |                 |                 |                 |
| <b>CONSEQUENCE REDUCTION</b>                                                                                              |                                                                                                                                                                                                                                                                                                                                                                      |                 |                 |                 |
| 9.                                                                                                                        | If consequence can be reduced due to any of the mitigation systems in Table 7.14, Section 7.8, decrease Equipment Damage Area (Line 7) by recommended percentage. This is the <i>Equipment Damage Area</i> . →                                                                                                                                                       | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 10.                                                                                                                       | If consequence can be reduced due to any of the mitigation systems in Table 7.14 of Section 7.8, decrease the unadjusted Area of Potential Fatalities (Line 8) by recommended percentage. This is the <i>Area of Fatalities</i> . →                                                                                                                                  | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |

| <b>Part C.2 TOXIC CONSEQUENCE CALCULATIONS</b>                                        |                                                                                                                                                                                                                                                                                                   |                     |                 |                 |                 |
|---------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------|-----------------|-----------------|-----------------|
| <b>Estimation of the toxic consequence area for a release of HF or H<sub>2</sub>S</b> |                                                                                                                                                                                                                                                                                                   |                     |                 |                 |                 |
| 1.                                                                                    | Copy material (Line 1 from Release Rate Calculation Workbook, Part A).<br>Note: Look-up tables have only been developed for HF & H <sub>2</sub> S.                                                                                                                                                |                     |                 |                 |                 |
|                                                                                       |                                                                                                                                                                                                                                                                                                   | <b>HOLE SIZES →</b> | <b>1/4 in.</b>  | <b>1 in.</b>    | <b>4 in.</b>    |
| 2.                                                                                    | Copy release type (Line 20 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                                                                       |                     |                 |                 |                 |
| 3.                                                                                    | Copy the release rate (Line 13 or 14 or 15 from Release Rate Calculation Workbook, Part A). For "instantaneous," skip to Line 8.                                                                                                                                                                  | lb/sec              | lb/sec          | lb/sec          | lb/sec          |
| 4.                                                                                    | Copy release durations from Line 21 on Release Rate Worksheet.                                                                                                                                                                                                                                    | min                 | min             | min             | min             |
| 5.                                                                                    | For "continuous," see Figure 7.5 (HF) or Figure 7.6 (H <sub>2</sub> S).<br>Select the curve with a release duration that matches or exceeds the duration shown in Line 4 above, up to 1 hour. Use the selected curve to find the consequence area corresponding to release rates given in Line 3. | ft <sup>2</sup>     | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 6.                                                                                    | For "instantaneous," enter total inventory released (Line 22 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                                     | lb                  | lb              | lb              | lb              |
| 7.                                                                                    | For "instantaneous," see Figure 7.8. Locate curve applicable to material selected.<br>Enter consequence area for release mass given in Line 6.                                                                                                                                                    | ft <sup>2</sup>     | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 8.                                                                                    | Enter the results of either Line 5 or Line 7 in this line. This is the toxic consequence area. →                                                                                                                                                                                                  | ft <sup>2</sup>     | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |

| <b>PART D RISK CALCULATIONS</b>                                          |                                                                                                                                            |                 |                 |                 |                 |
|--------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------|-----------------|-----------------|-----------------|-----------------|
| <b>Risk values for release scenario from a single piece of equipment</b> |                                                                                                                                            |                 |                 |                 |                 |
| HOLE SIZES →                                                             |                                                                                                                                            | 1/4 in.         | 1 in.           | 4 in.           | Rupture         |
| 1.                                                                       | Enter the generic failure frequency by hole size from Table 8.1.                                                                           |                 |                 |                 |                 |
| 2.                                                                       | Calculate Sum of Failure Frequencies                                                                                                       | /yr             |                 |                 |                 |
| 3.                                                                       | Calculate fraction contribution of each hole size by dividing the hole size generic frequency by the sum of the generic frequencies.       | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 4.                                                                       | Copy flammable consequence results (Line 9 - Equipment Damage or Line 10—Area of Fatalities from Flammable Consequence Workbook, Part C.1) | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 5.                                                                       | Multiply each value in Line 4 by the corresponding fraction in Line 3.                                                                     | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 6.                                                                       | Copy toxic consequence results (Line 10 from Toxic Consequence Workbook, Part C.2)                                                         | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 7.                                                                       | Multiply each value in Line 6 by the corresponding fraction in Line 3.                                                                     | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 8.                                                                       | Sum the values from Line 5. This is the Flammable Consequence area value.                                                                  | ft <sup>2</sup> |                 |                 |                 |
| 9.                                                                       | Sum the values from Line 7. This is the Toxic Consequence area value.                                                                      | ft <sup>2</sup> |                 |                 |                 |
| 10.                                                                      | Convert the value from either Line 7 or Line 8 to a category according to Appendix VIII, Table B-3. This is the Consequence Category.      |                 |                 |                 |                 |
| 11.                                                                      | Copy the Likelihood Category from Part B, Line 10 of this workbook.                                                                        |                 |                 |                 |                 |
| 12.                                                                      | Convert the categories from Lines 10 and 11 to a risk category using Appendix VIII, Figure 2.                                              |                 |                 |                 |                 |



## **APPENDIX C—WORKBOOK FOR QUANTITATIVE RISK-BASED INSPECTION ANALYSIS**

### **C.1 Overview of Quantitative Workbook**

This quantitative workbook is intended to be used as a work sheet in conjunction with the Base Resource Document (BRD) approach to quantitative RBI. It captures the information and calculations defined in Sections 6 through 8, and guides the user through each step required to estimate risk values. The workbook is designed for use on a single piece of equipment. It calculates the four different consequences covered in the Risk-Based Inspection BRD:

- a. Flammable consequences.
- b. Toxic consequences.
- c. Environmental consequences.
- d. Business interruption consequences.

The results for flammable and toxic consequences are given as affected area. The environmental and business interruption consequences are calculated as economic loss (in dollars).

In order to perform the quantitative RBI calculations, some characteristics of the release need to be defined. Part A of this workbook covers these initial calculations to determine release rate, type, duration, etc.

A likelihood analysis (Part B) is then carried out to obtain failure frequency data for the facility, using generic failure rate data as the starting point. These generic data are modified based on several factors that could increase or decrease the frequency. The factors taken into account to more accurately represent the likelihood of failure for frequency of the specific equipment at the given plant are:

- a. Technical Module—A measure of damage rate and inspection effectiveness.
- b. Universal—Factors that generally apply to the whole plant
- c. Mechanical—Factors related specifically to the equipment
- d. Process—Evaluation of process stability and relief valves
- e. Process Safety Management—Modification factor from Management Systems Evaluation

Risk is calculated last (Part D), as a product of the likelihood factor and each of the four consequences. The four risk types of interest to this study (i.e., flammable, toxic, environmental, and business interruption) are calculated for the piece of equipment of interest. The above process, repeated for all pieces of equipment within a unit or plant, will produce risk measures that can help prioritize the equipment based on its potential risk.

|                                                                                                                                                                                    |                                                                                                                                                                                        |                   |              |              |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------|--------------|--------------|
| Project No:                                                                                                                                                                        |                                                                                                                                                                                        |                   |              |              |
| Operating Unit:                                                                                                                                                                    |                                                                                                                                                                                        |                   |              |              |
| Equipment No:                                                                                                                                                                      |                                                                                                                                                                                        |                   |              |              |
| Description:                                                                                                                                                                       |                                                                                                                                                                                        |                   |              |              |
| <b>Part A. Release Rate Calculation</b><br><b>Section 7.4</b><br>Estimation of release rates for difference hole sizes and release types and durations for each of the hole sizes. |                                                                                                                                                                                        |                   |              |              |
| <b>Step I. Calculate Release Rate</b>                                                                                                                                              |                                                                                                                                                                                        |                   |              |              |
| 1.                                                                                                                                                                                 | Enter representative material contained in equipment being evaluated. (Table 7.1 in Section 7.1)                                                                                       |                   |              |              |
| 2.                                                                                                                                                                                 | Enter inventory for equipment, using the maximum inventory that can be released. Include inventories from vessels that cannot readily be isolated (within 5 minutes).                  | lb                |              |              |
| 3.                                                                                                                                                                                 | Use Table 7.4 to enter detection rating applicable to the detection systems present in the area.                                                                                       |                   |              |              |
| 4.                                                                                                                                                                                 | Use Table 7.4 to enter isolation rating applicable to the isolation systems present in the area.                                                                                       |                   |              |              |
| 5.                                                                                                                                                                                 | Use Table 7.5 to estimate leak duration based on detection and isolation systems                                                                                                       | 1/4 in.<br>min    | 1 in.<br>min | 4 in.<br>min |
| 6.                                                                                                                                                                                 | Enter operating pressure.                                                                                                                                                              | psia              |              |              |
| 7.                                                                                                                                                                                 | Circle gas or liquid, depending on the phase of the fluid in the equipment. If liquid, skip to Line 15.                                                                                | Gas               |              | Liquid       |
|                                                                                                                                                                                    | Gas Release Rate                                                                                                                                                                       |                   |              |              |
| 8.                                                                                                                                                                                 | Enter the process temperature.                                                                                                                                                         | °F                |              |              |
| 9.                                                                                                                                                                                 | From standard tables of fluid properties, enter the heat capacity ( $C_p$ ) of the gas at temperature given in Line 8.                                                                 | BTU/lb-mol °F     |              |              |
| 10.                                                                                                                                                                                | Calculate and enter $K[K = C_p(C_p - R)]$ where $R$ is ideal gas constant. (1.987 BTU/lb-mol °F)                                                                                       |                   |              |              |
| 11.                                                                                                                                                                                | Calculate and enter transition pressure ( $P_{trans}$ ), using Equation 7.2 in Section 7.4.                                                                                            | psia              |              |              |
| 12.                                                                                                                                                                                | Is fluid pressure inside the equipment greater than transition pressure (Line 6 > Line 11)?<br>If yes, circle "sonic," go to Line 13.<br>If no, circle "subsonic" and skip to Line 14. | Sonic<br>Subsonic |              |              |

|                                                                                                                                                                                   |                                                                                                                                       |         |        |        |         |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------|---------|--------|--------|---------|
| <b>Part A. Release Rate Calculation</b><br><b>Section 7.4</b><br>Estimation of release rates for difference hole sizes and release types and durations for each of the hole sizes |                                                                                                                                       |         |        |        |         |
|                                                                                                                                                                                   | Hole Sizes                                                                                                                            | 1/4 in. | 1 in.  | 4 in.  | Rupture |
| 13.                                                                                                                                                                               | Use sonic Equation 7.3 in Section 7.4 to calculate release rate for each of the listed hole sizes and enter rate. Skip to Line 16.    | lb/sec  | lb/sec | lb/sec | lb/sec  |
| 14.                                                                                                                                                                               | Use subsonic Equation 7.4 in Section 7.4 to calculate release rate for each of the listed hole sizes and enter rate. Skip to Line 16. | lb/sec  | lb/sec | lb/sec | lb/sec  |
|                                                                                                                                                                                   | Liquid Release Rate.                                                                                                                  |         |        |        |         |
| 15.                                                                                                                                                                               | Use liquid release Equation 7.1 in Section 7.4 to calculate release rate. Enter rate. Go to Line 16.                                  | lb/sec  | lb/sec | lb/sec | lb/sec  |

| Step II. Determine Release Type For Each Hole Size |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |         |       |        |         |
|----------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------|-------|--------|---------|
| 16.                                                | Divide maximum permissible released inventory by the appropriate release rate = Line 2, (Line 13, 14, or 15). Divide by 60 to get minutes. Enter value. This is the time required to deinventory, based on initial flow rates.                                                                                                                                                                                                                                                                                                                                                                                                                             | min     | min   | min    | min     |
| 17.                                                | Is release duration (Line 16) less than 3 minutes? If yes, then Instantaneous, otherwise Continuous.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |         |       |        |         |
| 18.                                                | Multiply release rate times 3 minute. [(Line 13, 14 or 15) x 180 seconds] Enter value.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     | lb      | lb    | lb     | lb      |
| 19.                                                | Is Line 18 > 10,000 lb? If yes, then Instantaneous, otherwise Continuous.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |         |       |        |         |
| 20.                                                | Enter the normal boiling point of the material.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            | °F      |       |        |         |
| 21.                                                | Enter the ambient state.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |         |       |        |         |
| 22.                                                | Refer to Table 7.3 to determine final state of the fluid.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  | Gas     |       | Liquid |         |
| 23.                                                | If both Line 17 and Line 19 indicate "CONT", enter Cont, otherwise enter Inst.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |         |       |        |         |
| 24.                                                | Enter the circled terms in Lines 22 and 23. The is the release type (i.e., continuous/instantaneous and gas/liquid).                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |         |       |        |         |
| 25.                                                | Look at Line 5 and at Line 16. For each hole size enter the lesser of the two. This is the release duration. For instantaneous, the duration is assumed to be 0.<br><br>(Release duration in Line 5 is based on detection/isolation and in Line 16 on inventory/release rate.)                                                                                                                                                                                                                                                                                                                                                                             | min.    | min.  | min.   | min.    |
| Hole Sizes                                         |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            | 1/4 in. | 1 in. | 4 in.  | Rupture |
| 26.                                                | <p>Calculate the maximum mass released in an instantaneous release based on equipment type and limited by the inventory group total (Line 2):</p> <ul style="list-style-type: none"> <li>• Piping—Calculate the inventory in the piping circuit and add the inventory resulting from a 3 minute flow through the largest piping diameter in the circuit.</li> <li>• Pumps—Calculate the inventory resulting from a 3 minute flow through the largest pump nozzle diameter.</li> <li>• Other Equipment—Calculate the Total Inventory (top and bottom) and add the inventory resulting from a 3 minute flow through the largest nozzle diameters.</li> </ul> | lb      | lb    | lb     | lb      |

|                                                                                                                                                                                                                                                                                                               |                                                                                                                                                                                                                    |         |       |       |         |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------|-------|-------|---------|
| <b>Part B. Likelihood Analysis</b>                                                                                                                                                                                                                                                                            |                                                                                                                                                                                                                    |         |       |       |         |
| Likelihood Analysis is the product of several factors that can indicate likelihood of equipment failure.                                                                                                                                                                                                      |                                                                                                                                                                                                                    |         |       |       |         |
| <b>Generic Failure Data</b>                                                                                                                                                                                                                                                                                   |                                                                                                                                                                                                                    |         |       |       |         |
| 1.                                                                                                                                                                                                                                                                                                            | Enter equipment type.                                                                                                                                                                                              |         |       |       |         |
|                                                                                                                                                                                                                                                                                                               | Hole Sizes                                                                                                                                                                                                         | 1/4 in. | 1 in. | 4 in. | Rupture |
| 2.                                                                                                                                                                                                                                                                                                            | Enter the generic failure frequency by hole size from Table 8.1.                                                                                                                                                   |         |       |       |         |
| <b>Equipment Modification Factor</b>                                                                                                                                                                                                                                                                          |                                                                                                                                                                                                                    |         |       |       |         |
| <b>Step I. Technical Modules Subfactor (Section 8.3.1)</b><br>Screen to identify damage mechanisms. Use appropriate damage mechanism technical module (see Appendix V) to determine individual factors.<br><br>If no damage mechanisms are identified, then enter -2 as technical module subfactor (Line 11). |                                                                                                                                                                                                                    |         |       |       |         |
| 3.                                                                                                                                                                                                                                                                                                            | Identified damage mechanisms                                                                                                                                                                                       |         |       |       |         |
|                                                                                                                                                                                                                                                                                                               | 3a. Thinning/Corrosion (Y/N)      Localized (Y/N)                                                                                                                                                                  |         |       |       |         |
|                                                                                                                                                                                                                                                                                                               | 3b. HTHA (Y/N)                                                                                                                                                                                                     |         |       |       |         |
|                                                                                                                                                                                                                                                                                                               | 3c. SCC (Y/N)                                                                                                                                                                                                      |         |       |       |         |
| Note: Items 4 through 7 are for recording certain basic information applicable to the Technical Modules. Not all items are required by each module, and not all data required by each Technical Module is presented below.                                                                                    |                                                                                                                                                                                                                    |         | 3a    | 3b    | 3c      |
| 4.                                                                                                                                                                                                                                                                                                            | Age of equipment in current service.                                                                                                                                                                               |         |       |       |         |
|                                                                                                                                                                                                                                                                                                               | 4A. Estimated/measured damage rate                                                                                                                                                                                 |         |       |       |         |
|                                                                                                                                                                                                                                                                                                               | 4B. Nelson Curve                                                                                                                                                                                                   |         |       |       |         |
|                                                                                                                                                                                                                                                                                                               | 4C. SCC Crack Size or Susceptibility                                                                                                                                                                               |         |       |       |         |
| 5.                                                                                                                                                                                                                                                                                                            | Calculate left column of Technical Module table                                                                                                                                                                    |         |       |       |         |
| 6.                                                                                                                                                                                                                                                                                                            | Determine inspection equivalents (H, U, F, P, I)                                                                                                                                                                   |         |       |       |         |
|                                                                                                                                                                                                                                                                                                               | 6A. Number of inspections                                                                                                                                                                                          |         |       |       |         |
| 7.                                                                                                                                                                                                                                                                                                            | Technical module subfactor from table                                                                                                                                                                              |         |       |       |         |
| 8.                                                                                                                                                                                                                                                                                                            | Correction for overdesign                                                                                                                                                                                          |         |       |       |         |
| 9.                                                                                                                                                                                                                                                                                                            | Correction for highly reliable damage rate data                                                                                                                                                                    |         |       |       |         |
| 10.                                                                                                                                                                                                                                                                                                           | Corrected technical module subfactor                                                                                                                                                                               |         |       |       |         |
| 11.                                                                                                                                                                                                                                                                                                           | Combined technical module subfactor                                                                                                                                                                                |         |       |       |         |
| <b>Step II. Universal Subfactor (Section 8.3.2)—All numeric values can be found in Section 8.3.2.</b>                                                                                                                                                                                                         |                                                                                                                                                                                                                    |         |       |       |         |
| 12.                                                                                                                                                                                                                                                                                                           | The Plant Condition Element is based on the current condition of the facility being evaluated, according to the professional judgment of the observer. The facility is ranked category _____. Enter numeric value. |         |       |       |         |
| 13.                                                                                                                                                                                                                                                                                                           | The Cold Weather Element recognizes that extreme low temperatures impose additional likelihood of failure of equipment. Enter numeric value.                                                                       |         |       |       |         |
| 14.                                                                                                                                                                                                                                                                                                           | The Seismic Activity Element correlates an increased likelihood of failure based on seismic zones. Enter seismic zone _____. Enter number value.                                                                   |         |       |       |         |
| 15.                                                                                                                                                                                                                                                                                                           | Combined Universal Subfactor ( $\Sigma$ Lines 12, 13, and 14)                                                                                                                                                      |         |       |       |         |

|                                                                                                                                                                                                                                       |                                                                                                                                                                                   |  |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--|
| <b>Step III. Mechanical Subfactor (Section 8.3.3)—All numeric values can be found in Section 8.3.3.</b><br>The Equipment Complexity Element is either the Piping Complexity Subelement or Vessel Complexity Subelement.               |                                                                                                                                                                                   |  |
| 16.                                                                                                                                                                                                                                   | For vessels only, the Vessel Complexity Subelement is related to the nozzle count. Enter nozzle count _____. Enter the value from Nozzle Count vs. Numeric Value Table.           |  |
| For piping only, the Piping Complexity Subelement requires 5 pieces of information. Lines 17 through 21 apply only to piping.                                                                                                         |                                                                                                                                                                                   |  |
| 17.                                                                                                                                                                                                                                   | (i) Enter number of connections x 10.                                                                                                                                             |  |
| 18.                                                                                                                                                                                                                                   | (ii) Enter number of injection points x 20.                                                                                                                                       |  |
| 19.                                                                                                                                                                                                                                   | (iii) Enter number of branches x 3.                                                                                                                                               |  |
| 20.                                                                                                                                                                                                                                   | (iv) Enter number of valves x 5.                                                                                                                                                  |  |
| 21.                                                                                                                                                                                                                                   | (v) Enter pipe length (ft).                                                                                                                                                       |  |
| 22.                                                                                                                                                                                                                                   | For piping only, calculate Piping Complexity Subelement ( $\Sigma$ Lines 17, 18, 19, 20/pipe length (ft)).                                                                        |  |
| 23.                                                                                                                                                                                                                                   | Equipment Complexity Subelement (Line 22 or Line 16).                                                                                                                             |  |
| 24.                                                                                                                                                                                                                                   | The Construction Code Element gives credit for safe operating experience with equipment designed to recognized codes. The equipment is built to construction code category _____. |  |
| 25.                                                                                                                                                                                                                                   | The Life Cycle Element assumes that failure frequency is higher early and late in the life of an equipment item.<br>Years in service _____ / Design Life _____ = _____ %          |  |
| The Safety Element accounts for the increased probability of failure for equipment operated with a higher ratio of operating to design pressure, or equipment operated at temperatures significantly above or below room temperature. |                                                                                                                                                                                   |  |
| 26.                                                                                                                                                                                                                                   | (i) Operating Pressure Sub-element<br>$P_{\text{operating}} \text{ _____ } / P_{\text{design}} \text{ _____ } = \text{ _____ }$                                                   |  |
| 27.                                                                                                                                                                                                                                   | (ii) Operating Temperature Subelement<br>$T_{\text{operating}} \text{ _____ }$                                                                                                    |  |
| 28.                                                                                                                                                                                                                                   | Safety Element ( $\Sigma$ Lines 26 and 27).                                                                                                                                       |  |
| 29.                                                                                                                                                                                                                                   | For rotating equipment, the Vibration Monitoring Element measures the predictive maintenance program (see Table 8.18).                                                            |  |
| 30.                                                                                                                                                                                                                                   | Combined Mechanical Subfactor ( $\Sigma$ Lines 23, 24, 25, 28, and 29).                                                                                                           |  |
| <b>Step IV Process Subfactor (Section 8.3.4)—All numeric values can be found in Section 8.3.4.</b><br>The Process Subfactor reflects the concern that process upsets will have a strong influence on mechanical integrity.            |                                                                                                                                                                                   |  |
| 31.                                                                                                                                                                                                                                   | (i) The Planned Shutdowns Subelement recognizes that even scheduled shutdowns may increase failure frequencies (see Table 8.19).                                                  |  |
| 32.                                                                                                                                                                                                                                   | (ii) The Unplanned Shutdowns Subelement requires averaging the number of unplanned shutdowns per year (see Table 8.20). Yearly average _____.                                     |  |
| 33.                                                                                                                                                                                                                                   | Continuity Element ( $\Sigma$ Lines 31, 32)                                                                                                                                       |  |
| 34.                                                                                                                                                                                                                                   | The Stability of Process Element (see Table 8.21) is developed from guidelines designed to characterize the stability ranking of the plant. Stability Ranking _____.              |  |
| The Relief Valve Element recognizes the importance of relief valves in protecting the equipment.                                                                                                                                      |                                                                                                                                                                                   |  |

|                                               |                                                                                                                                                     |                                                |
|-----------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------|
| 35.                                           | The RV Maintenance Subelement (see Table 8.22) measures some key parameters of the program. RV maintenance category _____.                          |                                                |
| 36.                                           | The compositions of the process stream can affect the reliability of the relief valves (see Table 8.23). Fouling Service Subelement category _____. |                                                |
| 37.                                           | Corrosive System Subelement (see Table 8.24) Y___ N___                                                                                              |                                                |
| 38.                                           | Very Clean Service Subelement (see Table 8.25) Y___ N___                                                                                            |                                                |
| 39.                                           | Relief Valve Element ( $\Sigma$ Lines 35, 36, 37, 38)                                                                                               |                                                |
| 40.                                           | Combined Process Subfactor ( $\Sigma$ Lines 33, 34, 39)                                                                                             |                                                |
| 41.                                           | Equipment Modification Factor ( $\Sigma$ Lines 11, 15, 30, 40)                                                                                      |                                                |
| Process Safety Management Modification Factor |                                                                                                                                                     |                                                |
| 42.                                           | Enter Score of PSM Modification Factor _____.<br>From Figure 8.5, PSM Modification Factor                                                           |                                                |
| Adjusted Failure Frequency                    |                                                                                                                                                     |                                                |
|                                               | Hole Sizes                                                                                                                                          | $\frac{1}{4}$ in.    1 in.    4 in.    Rupture |
| 43.                                           | Multiply Generic Failure Frequency $\times$ Equipment Modification Factor $\times$ PSM Factor (Line 2 $\times$ Line 41 $\times$ Line 42).           |                                                |

|                                                                                                                    |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
|--------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------|--------------|--------------|--------------|
| Part C.1 Flammable Consequence Calculations<br>Section 7.8                                                         |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
| Estimation of the flammable consequences area for equipment and personnel due to an ignited release of hydrocarbon |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
| Representative Material                                                                                            |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
| 1.                                                                                                                 | Copy representative material (Line 1 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                                                 |                   |              |              |              |
|                                                                                                                    | Hole Sizes                                                                                                                                                                                                                                                                            | $\frac{1}{4}$ in. | 1 in.        | 4 in.        | Rupture      |
| Release Type                                                                                                       |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
| 2.                                                                                                                 | Copy release type (Line 23 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                                                           |                   |              |              | inst.        |
| Release Rate Or Mass                                                                                               |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
| 3.                                                                                                                 | Copy the release rate or mass (Line 13 or 14 or 15 or 28 from Release Rate Calculation Workbook, Part A), depending on the type of release.                                                                                                                                           | lb or lb/min      | lb or lb/min | lb or lb/min | lb or lb/min |
| Detection Rating                                                                                                   |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
| 4.                                                                                                                 | Copy Line 3 from Release Rate Worksheet (detection rating applicable to the detection systems present in the area).                                                                                                                                                                   |                   |              |              |              |
| Isolation Rating                                                                                                   |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
| 5.                                                                                                                 | Copy Line 4 from Release Rate Worksheet (isolation rating applicable to the isolation systems present in the area).                                                                                                                                                                   |                   |              |              |              |
| Adjustments For Flammable Event Mitigation                                                                         |                                                                                                                                                                                                                                                                                       |                   |              |              |              |
| 6.                                                                                                                 | Look at Table 7.10 in Section 7.8 to adjust release rates or mass based on Line 4 and 5 above. Enter adjusted release rate or mass.<br><br>For mitigation systems that reduce consequence area (fire water deluge system, monitors, or foam spray system), make adjustment on Line 9. | lb or lb/min      | lb or lb/min | lb or lb/min |              |

| Equipment Damage Area     |                                                                                                                                                                                                                                                                                                                                                                        |                 |                 |                 |
|---------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------|-----------------|-----------------|
| 7.                        | Look at Equipment Damage equations in Consequence Equation Tables 7.10 and 7.13 and replace "x" by adjusted release rate or mass (Line 6) in appropriate equations. (Use the information in Lines 1, 2, and 3 to select the correct equation) Use Table 7.12 or 7.13 if the fluid is at 80°F above its auto ignition temperature, otherwise use Table 7.10 or 7.11.    | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| Potential Fatalities Area |                                                                                                                                                                                                                                                                                                                                                                        |                 |                 |                 |
| 8.                        | Look at Area of Potential Fatalities in Consequence Equation Tables 7.10 and 7.13 and replace "x" by adjusted release rate or mass (Line 6) in appropriate equations. (Use the information in Lines 1, 2, and 3 to select the correct equation) Use Table 7.12 or 7.13 if the fluid is at 80 °F above its auto ignition temperature, otherwise use Table 7.10 or 7.11. | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| Consequence Reduction     |                                                                                                                                                                                                                                                                                                                                                                        |                 |                 |                 |
| 9.                        | If consequence can be reduced due to any of the mitigation systems in Table 7.14, Section 7.8, decrease Equipment Damage Area (Line 7) by recommended percentage. This is the Equipment Damage Area                                                                                                                                                                    | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 10.                       | If consequence can be reduced due to any of the mitigation systems in Table 7.14 of Section 7.8, decrease the unadjusted Area of Potential Fatalities (Line 8) by recommended percentage. This is the Area of Fatalities.                                                                                                                                              | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |

| Part C.2 Toxic Consequence Calculations<br>Section 7.8.2<br>Estimation of the toxic consequences area for a release of HF or H <sub>2</sub> S. |                                                                                                                                                                                                                                                                                        |                 |                 |                 |
|------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------|-----------------|-----------------|
| 1.                                                                                                                                             | Enter toxic material and percent of toxic material. Note: Look-up tables have only been developed for HF and H <sub>2</sub> S.                                                                                                                                                         |                 |                 |                 |
| Hole Sizes                                                                                                                                     |                                                                                                                                                                                                                                                                                        | 1/4 in.         | 1 in.           | 4 in.           |
| 2.                                                                                                                                             | Copy release type (Line 24 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                                                            |                 |                 |                 |
| 3.                                                                                                                                             | Multiply the release rate (Line 13 or 14 or 15 from Release Rate Calculation Workbook, Part A) by the percent of toxic material. For "instantaneous," skip to Line 8.                                                                                                                  | lb/sec          | lb/sec          | lb/sec          |
| 4.                                                                                                                                             | Copy release durations (Line 25 on Release Rate Calculation Workbook, Part A.)                                                                                                                                                                                                         | min             | min             | min             |
| 5.                                                                                                                                             | Is there a water spray/deluge system? Y ____ N ____                                                                                                                                                                                                                                    |                 |                 |                 |
| 6.                                                                                                                                             | If Line 5 is "yes," use spray system design information to estimate reduction in release rate or mass. Enter adjusted release rate or mass.                                                                                                                                            | lb/sec          | lb/sec          | lb/sec          |
| 7.                                                                                                                                             | For "continuous," see Figure 7-5 (HF) or Figure 7-6 (H <sub>2</sub> S).<br><br>Locate the curve with the next highest release duration.<br><br>Enter consequence area corresponding to release rates given in Line 6 (if deluge system is available) or in Line (if no deluge system). | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 8.                                                                                                                                             | For "instantaneous," enter total inventory released (Line 28 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                          | lb              | lb              | lb              |
| 9.                                                                                                                                             | For "instantaneous," see Figure 7-8. Locate curve applicable to material selected. Enter consequence area for release mass given in Line 8.                                                                                                                                            | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 10.                                                                                                                                            | Enter the results of either Line 7 or Line 9 in this line. This is the toxic consequence area.                                                                                                                                                                                         | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |

|                                                                                                             |                                                                                                                                                                                                                                                                                                                                                                        |                   |         |         |
|-------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------|---------|---------|
| <b>Part C.3 Environmental Consequence Calculations</b>                                                      |                                                                                                                                                                                                                                                                                                                                                                        |                   |         |         |
| Section 7.8.3                                                                                               |                                                                                                                                                                                                                                                                                                                                                                        |                   |         |         |
| Estimation of the economic loss (in dollars) due to a liquid spill and its associated cleanup               |                                                                                                                                                                                                                                                                                                                                                                        |                   |         |         |
| <b>Step I. Calculate Volume Released</b>                                                                    |                                                                                                                                                                                                                                                                                                                                                                        |                   |         |         |
| 1.                                                                                                          | Copy normal boiling point (NBP) of the material (Line 20 from Release Rate Calculation Workbook, Part A).<br>If NBP < -300 °F enter "Not applicable." There will be no acute environmental consequences from failure of this equipment. Otherwise, continue.                                                                                                           | °F                |         |         |
| 2.                                                                                                          | Copy maximum inventory available (Line 28 from Release Rate Calculation Workbook, Part A).                                                                                                                                                                                                                                                                             | lb                |         |         |
| 3.                                                                                                          | Enter liquid density of material at atmospheric pressure and temperature.                                                                                                                                                                                                                                                                                              | lb/gal            |         |         |
| 4.                                                                                                          | Multiply liquid density by maximum inventory available (Line 2–Line 3). This is the maximum permissible volume of liquid that could spill ( $V_{\max}$ ).                                                                                                                                                                                                              | gal               |         |         |
| <b>Below Ground Release</b>                                                                                 |                                                                                                                                                                                                                                                                                                                                                                        | $\frac{1}{4}$ in. | 1 in.   | 4 in.   |
| 5.                                                                                                          | Is release from a vessel wall that may leak below grade?<br>If answer is "no" skip to Line 10. Y ___ N ___                                                                                                                                                                                                                                                             |                   |         |         |
| 6.                                                                                                          | Enter corresponding leak rates based on type of foundation.<br><br>(See Table 7.13 in Section 7.8.3).<br>For instantaneous cases, use leak rates for largest hole size available (4 in.).<br><br>Instantaneous releases below ground are treated as continuous releases due to the soil surrounding all sides of the tank, thus preventing an instantaneous discharge. | gal/day           | gal/day | gal/day |
| 7.                                                                                                          | Enter corresponding detection times or threshold of mass released based on method of detection (See Table 7.13 in Section 7.8.3).                                                                                                                                                                                                                                      | days              | days    | days    |
| 8.                                                                                                          | Calculate volume released by multiplying Line 6 and Line 7. Enter value. This is the volume released below ground.                                                                                                                                                                                                                                                     | gal               | gal     | gal     |
| 9.                                                                                                          | Is volume released below ground > maximum available volume? (Line 8 > Line 4)? Y ___ N ___<br>If "yes", enter values in Line 4.<br>If "no," enter values in Line 8.<br>If other walls of the vessel are above ground, go to Line 10. Otherwise, skip to Line 12.                                                                                                       |                   |         |         |
| <b>Above Ground Release</b>                                                                                 |                                                                                                                                                                                                                                                                                                                                                                        | $\frac{1}{4}$ in. | 1 in.   | 4 in.   |
| 10.                                                                                                         | Multiply liquid release rate times isolation time. This is amount of material released. (Line 15 x Line 5, from Release Rate Calculation Workbook, Part A). Do not exceed value in Line 2, Part C.3.                                                                                                                                                                   | lb                | lb      | lb      |
| 11.                                                                                                         | Multiply liquid density by material released (Line 3 x Line 10) to obtain volume spilled. Enter volume spilled. If material released is more than maximum permissible inventory (Line 10 > Line 2), use maximum permissible inventory to calculate volume spilled.                                                                                                     | gal               | gal     | gal     |
| <b>Step II. Eliminate Scenarios With No Environmental Impact (Above ground, diked, and continuous only)</b> |                                                                                                                                                                                                                                                                                                                                                                        |                   |         |         |
| 12.                                                                                                         | Enter secondary containment (i.e. dike) volume - if no dike, enter 0 and skip to Line 17.                                                                                                                                                                                                                                                                              | gal               |         |         |



|                                                          |                                                                                                                                                                                                                                                                                                                                                                                                                                       |                   |           |           |           |
|----------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------|-----------|-----------|-----------|
| 13.                                                      | Assuming a rectangular dike, identify which of its 4 sides are critical barriers (i.e: such as a fence line wall, if spill goes over that wall, it will need cleanup; non-critical would be walls common to adjacent dikes).<br><br>Enter fraction of critical ( $K_{crit}$ ) walls (0, $\frac{1}{4}$ , $\frac{1}{2}$ , 1).<br><br>If $K_{crit} = 0$ , the scenario can be discarded. Skip to Line 30 and write 0 for all hole sizes. |                   |           |           |           |
| 14.                                                      | Subtract released volume from dike volume (Line 11–Line 12).                                                                                                                                                                                                                                                                                                                                                                          | gal               | gal       | gal       | gal       |
| 15.                                                      | Is released volume < dike volume? (Is Line 14 < 0)<br>Circle Yes or No.                                                                                                                                                                                                                                                                                                                                                               | Yes<br>No         | Yes<br>No | Yes<br>No | Yes<br>No |
| 16.                                                      | Is dike un-bypassable and impervious? (i.e., cannot be opened)<br>Circle Yes or No.                                                                                                                                                                                                                                                                                                                                                   | Yes               | No        |           |           |
| 17.                                                      | If both Line 15 and 16 are “yes,” enter 0 here and in Line 30 for appropriate hole sizes. Skip these hole sizes in Line 18 and Line 19.<br><br>Otherwise, continue.                                                                                                                                                                                                                                                                   |                   |           |           |           |
| Step III. Estimate Volume Escaping To Environment        |                                                                                                                                                                                                                                                                                                                                                                                                                                       | $\frac{1}{4}$ in. | 1 in.     | 4 in.     | Rupture   |
| Continuous Release                                       |                                                                                                                                                                                                                                                                                                                                                                                                                                       |                   |           |           |           |
| 18.                                                      | For releases above ground with no dike, volume to environment ( $V_{env}$ ) equals volume in Line 11.                                                                                                                                                                                                                                                                                                                                 |                   |           |           |           |
| 19.                                                      | Enter the probability that the dike drain may be open (suggested value of 0.025).                                                                                                                                                                                                                                                                                                                                                     |                   |           |           |           |
| 20.                                                      | Multiply dike volume by Line 19.                                                                                                                                                                                                                                                                                                                                                                                                      | gal               |           |           |           |
| 21.                                                      | Add Line 20 to Line 14. This is the volume released to the environment from non-rupture leaks.                                                                                                                                                                                                                                                                                                                                        | gal               | gal       | gal       | gal       |
| 22.                                                      | For a continuous release, if Line 14 is < 0, enter the value of Line 14 as volume released to environment ( $V_{env}$ ).                                                                                                                                                                                                                                                                                                              | gal               | gal       | gal       | gal       |
| Amount Overflowing Dike Wall                             |                                                                                                                                                                                                                                                                                                                                                                                                                                       |                   |           |           |           |
| 23.                                                      | Calculate ratio of maximum permissible volume released to the volume of dike (Line 4/ Line 12). Enter value.                                                                                                                                                                                                                                                                                                                          |                   |           |           |           |
| 24.                                                      | From Table 7-19 in Section 7.8.3, obtain the volume factor $K_{vol}$ corresponding to value in Line 20. Enter $K_{vol}$ .                                                                                                                                                                                                                                                                                                             |                   |           |           |           |
| 25.                                                      | Enter the average distance from the tank center to the critical dike walls.                                                                                                                                                                                                                                                                                                                                                           | ft                |           |           |           |
| 26.                                                      | Enter the vessel radius.                                                                                                                                                                                                                                                                                                                                                                                                              | ft                |           |           |           |
| 27.                                                      | Enter the ratio of the average distance from vessel center to critical walls and the vessel radius ( $K_d = \text{Line 25}/\text{Line 26}$ ).                                                                                                                                                                                                                                                                                         |                   |           |           |           |
| 28.                                                      | Multiply Line 4 $\times$ Line 13 $\times$ Line 24 $\times$ Line 27. This is the volume spilled to environment from an instantaneous release ( $V_{env} = V_{max} \times K_{crit} \times K_{vol} K_d$ ).                                                                                                                                                                                                                               | gal               |           |           |           |
| 29.                                                      | Add Lines 22 and 28 above to determine the total above- ground release volume.                                                                                                                                                                                                                                                                                                                                                        | gal               |           |           |           |
| Step IV. Estimate Final Liquid Volume—Above Ground Only. |                                                                                                                                                                                                                                                                                                                                                                                                                                       |                   |           |           |           |
| 30.                                                      | Enter evaporation constant for material (K)<br>(See Tables 7-19 or Figures 7-10 through 7-13 in Section 7.8.3).                                                                                                                                                                                                                                                                                                                       |                   |           |           |           |

|                                                    |                                                                                                                                                                                                                                              |        |    |    |    |
|----------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------|----|----|----|
| 31.                                                | Enter estimated time required to complete $1/2$ of the clean-up efforts ( $t_{1/2}$ )                                                                                                                                                        | hrs    |    |    |    |
| 32.                                                | Calculate Final Liquid Volume Factor $F_{\text{liquid}}$ (quantification of unevaporated liquid). Use Equation 7.12 in Section 7.8.3 which is a function of $K$ and $t_{1/2}$ .<br>If the release is below ground, $F_{\text{liquid}} = 1$ . |        |    |    |    |
| <b>Step V. Determine Unit Volume Cleanup Costs</b> |                                                                                                                                                                                                                                              |        |    |    |    |
| 33.                                                | Enter the estimated unit cost of clean-up for below ground clean up (if no data are available, some suggested cost values are listed in Table 7.16 in Section 7.8.3).                                                                        | \$/gal |    |    |    |
| 34.                                                | Enter the estimate for above ground clean up costs, Table 7.20.                                                                                                                                                                              | \$/gal |    |    |    |
| 35.                                                | Determine clean up costs below ground - multiply Line 9 by the clean up cost for below ground clean up (Line 33).                                                                                                                            | \$     | \$ | \$ | \$ |
| 36.                                                | Above ground—multiply Line 32 by Line 34 to determine above ground clean up costs.                                                                                                                                                           | \$     | \$ | \$ | \$ |
| 37.                                                | Add Lines 35 and 36 to determine total clean up costs for this equipment item.                                                                                                                                                               | \$     | \$ | \$ | \$ |

|                                                                                                                                                                                                            |                                                                                                                                                                                                                                                 |                    |                             |                 |                 |                |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------|-----------------------------|-----------------|-----------------|----------------|
| <b>Part C.4 Business Interruption Calculations</b><br>Daily Value Loss Approach—Section 7.8.4<br>Estimation of economic loss due to business interruption, if the loss per day due to a shutdown is known. |                                                                                                                                                                                                                                                 |                    |                             |                 |                 |                |
| 1.                                                                                                                                                                                                         | Enter the loss per day if the unit/facility is shutdown.                                                                                                                                                                                        | \$/day             |                             |                 |                 |                |
| 2.                                                                                                                                                                                                         | Estimate the cost of the equipment in the facility per square feet.<br>Enter the figure here.                                                                                                                                                   | \$/ft <sup>2</sup> |                             |                 |                 |                |
|                                                                                                                                                                                                            |                                                                                                                                                                                                                                                 | <b>Hole Sizes</b>  | <b><math>1/4</math> in.</b> | <b>1 in.</b>    | <b>4 in.</b>    | <b>Rupture</b> |
| 3.                                                                                                                                                                                                         | Enter the flammable consequence, in terms of area of equipment lost, from the Flammable Consequence Workbook (Part C1, Line 9).                                                                                                                 | ft <sup>2</sup>    | ft <sup>2</sup>             | ft <sup>2</sup> | ft <sup>2</sup> |                |
| 4.                                                                                                                                                                                                         | Multiply Line 2 by Line 3 and enter. This is the Equipment Damage Loss due to flammable event.                                                                                                                                                  | \$4                | \$                          | \$              | \$              |                |
| 5.                                                                                                                                                                                                         | Using the Figure 7.14, Business Interruption vs. Equipment Damage, enter the business outage days corresponding to the equipment damage in Line 4.                                                                                              | days               | days                        | days            | days            |                |
| 6.                                                                                                                                                                                                         | Is the equipment being evaluated unique or difficult to replace, and would its loss result in extended shutdown of the facility? If yes, enter estimated time of shutdown.<br>If no, enter 0.                                                   | days               |                             |                 |                 |                |
| 7.                                                                                                                                                                                                         | For each hole size, use Table 7.21 to estimate the potential for a flammable event from this equipment to damage neighboring critical equipment, such as power lines, control cables, etc. Use the area in Line 3 to help gauge the likelihood. |                    |                             |                 |                 |                |
| 8.                                                                                                                                                                                                         | Estimate the resulting downtime due to damage of neighboring critical equipment, and enter the number of days here.                                                                                                                             | days               | days                        | days            | days            |                |
| 9.                                                                                                                                                                                                         | Multiply Line 7 by Line 8. This is the expected Unit Downtime due to damage of neighboring equipment.                                                                                                                                           | days               | days                        | days            | days            |                |

|     |                                                                                                                                                                                                                                                |                     |                 |                 |                 |
|-----|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------|-----------------|-----------------|-----------------|
| 10. | Enter the largest of Lines 5, 6, and 9 above. Repeat for each hole size. This is the unit downtime due to the flammable incident.                                                                                                              | days                | days            | days            | days            |
| 11. | Multiply each column of Line 10 by Line 1. This is the Business Interruption Loss due to the flammable consequence, for each hole size.                                                                                                        | \$                  | \$              | \$              | \$              |
| 12. | Enter the number 5 in this column. This is the default base multiplier.                                                                                                                                                                        | 5                   |                 |                 |                 |
|     | Hole Sizes                                                                                                                                                                                                                                     | 1/4 in.             | 1 in.           | 4 in.           | Rupture         |
| 13. | Estimate the company's ability to replace the damaged equipment. Refer to Table 7.22 in Section 7.8.4.                                                                                                                                         |                     |                 |                 |                 |
| 14. | Estimate the potential for this incident to damage neighboring critical equipment, such as power lines, control cables, etc. Do the estimation for each hole size, based on the damage area shown in Line 3. Use Table 7.23 for probabilities. |                     |                 |                 |                 |
| 15. | Estimate the consequence factor of the incident to neighboring critical equipment. This value is also obtained from Table 7.24.                                                                                                                |                     |                 |                 |                 |
| 16. | Multiply Line 14 by Line 15 and enter the result on this line.                                                                                                                                                                                 |                     |                 |                 |                 |
| 17. | To what extent does the loss of product from this unit affect operations in other facilities/units? Enter one number based on the information in Table 7.25.                                                                                   |                     |                 |                 |                 |
| 18. | Add the values in lines 12, 13, 16 and 17. Enter the result here. This is the overall multiplier for each hole size release.                                                                                                                   |                     |                 |                 |                 |
| 19. | Enter the cost of equipment per unit area.                                                                                                                                                                                                     | \$ /ft <sup>2</sup> |                 |                 |                 |
| 20. | Enter the flammable consequence, in terms of area of equipment lost, from Line 3 in this section of the workbook.                                                                                                                              | ft <sup>2</sup>     | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 21. | Multiply Line 19 by Line 20. This is the Equipment Damage Loss for each hole size release.                                                                                                                                                     | \$                  | \$              | \$              | \$              |
| 22. | Multiply the value in Line 18 with the dollar amount in Line 21. Enter the result here. This is the business interruption loss for each hole size release.                                                                                     |                     |                 |                 |                 |

|                                                                                                            |                                                                                                                                           |                 |                 |                 |                 |
|------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------|-----------------|-----------------|-----------------|-----------------|
| Part D. Risk Calculations—Section 6.3<br>Risk values for release scenario from a single piece of equipment |                                                                                                                                           |                 |                 |                 |                 |
|                                                                                                            | Hole Sizes                                                                                                                                | 1/4 in.         | 1 in.           | 4 in.           | Rupture         |
| 1.                                                                                                         | Copy frequency results (Line 43 from Part B, Likelihood Analysis Workbook).                                                               | /yr             | /yr             | /yr             | /yr             |
| 2.                                                                                                         | Copy flammable consequence results (Line 9—Equipment Damage or Line 10—Area of Fatalities from Flammable Consequence Workbook, Part C.1). | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 3.                                                                                                         | Copy toxic consequence results (Line 10 from Toxic Consequence Workbook, Part C.2).                                                       | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> | ft <sup>2</sup> |
| 4.                                                                                                         | Copy environmental consequence results (Line 37 from Environmental Consequence Workbook, Part C.3).                                       | \$              | \$              | \$              | \$              |
| 5.                                                                                                         | Copy business interruption results (Line 11 or Line 22 from either method of Business Interruption Consequence Workbook, C.4).            | \$              | \$              | \$              | \$              |

| Step I. Calculate Risk Results                           |                                                                                                |                     |                     |                     |                     |
|----------------------------------------------------------|------------------------------------------------------------------------------------------------|---------------------|---------------------|---------------------|---------------------|
| 6.                                                       | Multiply flammable consequence results by the frequency results (Line 1 x Line 2).             | ft <sup>2</sup> /yr | ft <sup>2</sup> /yr | ft <sup>2</sup> /yr | ft <sup>2</sup> /yr |
| 7.                                                       | Multiply toxic consequence results by the frequency results (Line 1 x Line 3).                 | ft <sup>2</sup> /yr | ft <sup>2</sup> /yr | ft <sup>2</sup> /yr | ft <sup>2</sup> /yr |
| 8.                                                       | Multiply environmental consequence results by the frequency results (Line 1 x Line 4).         |                     |                     |                     |                     |
| 9.                                                       | Multiply business interruption consequence results by the frequency results (Line 1 x Line 5). |                     |                     |                     |                     |
| 10.                                                      | Sum flammable risks for all hole sizes ( $\Sigma$ Line 6).                                     | ft <sup>2</sup> /yr |                     |                     |                     |
| 11.                                                      | Sum toxic risks for all hole sizes ( $\Sigma$ Line 7).                                         | ft <sup>2</sup> /yr |                     |                     |                     |
| 12.                                                      | Sum environmental risks for all hole sizes ( $\Sigma$ Line 8).                                 | \$/yr               |                     |                     |                     |
| 13.                                                      | Sum business interruption risks for all hole sizes ( $\Sigma$ Line 9).                         | \$/yr               |                     |                     |                     |
| Step II. Calculate Risk-weighted Individual Consequences |                                                                                                |                     |                     |                     |                     |
| 14.                                                      | Sum frequencies for all hole sizes ( $\Sigma$ Line 1).                                         | /yr                 |                     |                     |                     |
| 15.                                                      | Find risk-weighted flammable consequences (Line 10/Line 14).                                   | ft <sup>2</sup>     |                     |                     |                     |
| 16.                                                      | Find risk-weighted toxic consequences (Line 11/Line 14).                                       | ft <sup>2</sup>     |                     |                     |                     |
| 17.                                                      | Find risk-weighted environmental consequences (Line 12/Line 14).                               | \$                  |                     |                     |                     |
| 18.                                                      | Find risk-weighted business interruption consequences (Line 13/Line 14).                       | \$                  |                     |                     |                     |

**APPENDIX D—WORKBOOK FOR MANAGEMENT  
SYSTEMS EVALUATION**

| Table of Contents |                               |           |        |
|-------------------|-------------------------------|-----------|--------|
| Section           | Title                         | Questions | Points |
| 1                 | Leadership and Administration | 6         | 70     |
| 2                 | Process Safety Information    | 10        | 80     |
| 3                 | Process Hazard Analysis       | 9         | 100    |
| 4                 | Management of Change          | 6         | 80     |
| 5                 | Operating Procedures          | 7         | 80     |
| 6                 | Safe Work Practices           | 7         | 85     |
| 7                 | Training                      | 8         | 100    |
| 8                 | Mechanical Integrity          | 20        | 120    |
| 9                 | Pre-Startup Safety Review     | 5         | 60     |
| 10                | Emergency Response            | 6         | 65     |
| 11                | Incident Investigation        | 9         | 75     |
| 12                | Contractors                   | 5         | 45     |
| 13                | Assessments                   | 4         | 40     |
|                   | Total                         | 101       | 1000   |

| 1.           | Leadership and Administration                                                                                                                                                                                                                                                                                | Possible Score        | Actual Score |
|--------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------|--------------|
|              | Leadership is considered crucial in implementing and sustaining an effective Process Safety Management effort.                                                                                                                                                                                               |                       |              |
| 1.1          | Does the organization at the corporate or local level have a general policy statement reflecting management's commitment to Process Safety Management, and emphasizing safety and loss control issues?                                                                                                       | 10                    |              |
| 1.2          | Is the general policy statement: <ul style="list-style-type: none"> <li>a. Contained in manuals?</li> <li>b. Posted in various locations?</li> <li>c. Included as a part of all rule booklets?</li> <li>d. Referred to in all major training programs?</li> <li>e. Used in other ways? (Describe)</li> </ul> | 2<br>2<br>2<br>2<br>2 |              |
| 1.3          | Are responsibilities for process safety and health issues clearly defined in every manager's job description?                                                                                                                                                                                                | 10                    |              |
| 1.4          | Are annual objectives in the area of process safety and health issues established for all management personnel, and are they then included as an important consideration in their regular annual appraisals?                                                                                                 | 15                    |              |
| 1.5          | What percentage of the total management team has participated in a formal training course or outside conference or seminar on Process Safety Management over the last three years?                                                                                                                           | % x 10                |              |
| 1.6          | Is there a site Safety Committee, or equivalent? <ul style="list-style-type: none"> <li>a. Does the committee make-up represent a diagonal slice of the organization?</li> <li>b. Does the committee meet regularly and document that appropriate recommendations are implemented?</li> </ul>                | 5<br>5<br>5           |              |
| Total Points |                                                                                                                                                                                                                                                                                                              | 70                    |              |

| 2.  | Process Safety Information                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        | Possible Score   | Actual Score |
|-----|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------|--------------|
| 2.1 | Are Material Safety Data Sheets (MSDS) available for all chemical substances used or handled in each unit? <ul style="list-style-type: none"> <li>a. Is the maximum on-site inventory of each of these chemicals listed?</li> <li>b. Is this information available to operations and maintenance personnel and any appropriate contract personnel in the unit?</li> <li>c. Are the hazardous effects, if any, of inadvertent mixing of the various materials on site clearly stated in the Standard Operating Procedures and emphasized in operator training programs?</li> </ul> | 5<br>2<br>2<br>2 |              |
| 2.2 | Are quality control procedures in place and practiced to ensure that all identified materials meet specifications when received and used?                                                                                                                                                                                                                                                                                                                                                                                                                                         | 10               |              |
| 2.3 | Is up-to-date written information readily available in the unit that: <ul style="list-style-type: none"> <li>a. Summarizes the process chemistry?</li> <li>b. Lists the safe upper and lower limits for such items as temperatures, pressures, flows and compositions?</li> <li>c. States the safety-related consequences of deviations from these limits?</li> </ul>                                                                                                                                                                                                             | 3<br>3<br>3      |              |

|              |                                                                                                                                                                                                                                                                                                                                                                                                    | Possible Score             | Actual Score |
|--------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------|--------------|
| 2.4          | Is a block flow diagram or simplified process flow diagram available to aid in the operator's understanding of the process?                                                                                                                                                                                                                                                                        | 5                          |              |
| 2.5          | Are P&IDs available for all units at the site?                                                                                                                                                                                                                                                                                                                                                     | 10                         |              |
| 2.6          | Does documentation show all equipment in the unit is designed and constructed in compliance with all applicable codes, standards, and generally accepted good engineering practices?                                                                                                                                                                                                               | 8                          |              |
| 2.7          | • Has all existing equipment been identified that was designed and constructed in accordance with codes, standards, or practices that are no longer in general use?                                                                                                                                                                                                                                | 4                          |              |
|              | • Has it been documented that the design, maintenance, inspection and testing of such equipment will allow it to be operated in a safe manner?                                                                                                                                                                                                                                                     | 4                          |              |
| 2.8          | Have written records been compiled for each piece of equipment in the process, and do they include all of the following?<br>a. Materials of construction.<br>b. Design codes and standards employed.<br>c. Electrical classification.<br>d. Relief system design and design basis.<br>e. Ventilation system design.<br>f. Safety systems, including interlocks, detection and suppression systems. | 1<br>1<br>1<br>1<br>1<br>1 |              |
| 2.9          | Are procedures in place to ensure that each individual with responsibility for managing the process has a working knowledge of the process safety information appropriate to his or her responsibilities?                                                                                                                                                                                          | 5                          |              |
| 2.10         | Is a documented compilation of all the above Process Safety Information maintained at the facility as a reference? The individual elements of the Information may exist in various forms and locations, but the compilation should confirm the existence and location of each element.                                                                                                             | 8                          |              |
| Total Points |                                                                                                                                                                                                                                                                                                                                                                                                    | 80                         |              |

| 3. Process Hazard Analysis |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          | Possible Score                 | Actual Score |
|----------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------|--------------|
| 3.1                        | What percentage of all process units that handle hazardous chemicals at the facility have had a formal Process Hazard Analysis (PHA) within the last five years?                                                                                                                                                                                                                                                                                                                                                         | % x 10                         |              |
| 3.2                        | Has a priority order been established for conducting future PHAs?<br><br>Does the basis for the prioritization address the following factors?:<br>a. The quantity of toxic, flammable, or explosive material at the site.<br>b. The level of toxicity or reactivity of the materials.<br>c. The number of people in the immediate proximity of the facility, including both onsite and offsite locations.<br>d. Process complexity.<br>e. Severe operating conditions or conditions that can cause corrosion or erosion. | 5<br><br>1<br>1<br>1<br>1<br>1 |              |

|              |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  | Possible Score                                                 | Actual Score |
|--------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------|--------------|
| 3.3          | <p>Do the PHAs conducted to date address:</p> <p>a. The hazards of the process?</p> <p>b. A review of previous incident/accident reports from the unit being analyzed to identify any previous incidents that had a potential for catastrophic consequences?</p> <p>c. Engineering and administrative controls applicable to the hazards and their interrelationships?</p> <p>d. Consequences of failure of engineering and administrative controls?</p> <p>e. Facilities siting?</p> <p>f. Human factors?</p> <p>g. A qualitative evaluation of the possible safety and health effects of failure of controls on employees?</p> | <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> |              |
| 3.4          | <p>Based on the most recent PHA conducted:</p> <p>a. Was the team leader experienced in the technique being employed?</p> <p>b. Had the team leader received formal training in the method being employed?</p> <p>c. Was at least one member of the team an expert on the process being analyzed?</p> <p>d. Were all appropriate disciplines represented on the team or brought in as required during the analysis?</p> <p>e. Was at least one member of the team a person who did not participate in the original design of the facility?</p>                                                                                   | <p>3</p> <p>3</p> <p>3</p> <p>3</p> <p>3</p>                   |              |
| 3.5          | <p>Is a formal system in place to promptly address the findings and recommendations of a Process Hazard Analysis to ensure that the recommendations are resolved in a timely manner and that the resolution is documented?</p> <p>a. If so, are timetables established for implementation?</p> <p>b. Does the system require that decisions concerning recommendations in PHAs and the status of implementation be communicated to all operations, maintenance and other personnel who may be affected?</p>                                                                                                                      | <p>8</p> <p>3</p> <p>3</p>                                     |              |
| 3.6          | Is the methodology used in past PHAs and/or planned future PHAs appropriate for the complexity of the process?                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   | 10                                                             |              |
| 3.7          | Are the PHAs being led by an individual who has been trained in the methods being used?                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          | 12                                                             |              |
| 3.8          | Based on the most recent PHAs conducted, are the average rates of analysis appropriate for the complexity of the systems being analyzed? (Typically, 2-4 P&IDs of average complexity will be analyzed per day.)                                                                                                                                                                                                                                                                                                                                                                                                                  | 10                                                             |              |
| 3.9          | After the process hazards have been identified, are the likelihood and consequences of the failure scenarios assessed using either qualitative or quantitative techniques?                                                                                                                                                                                                                                                                                                                                                                                                                                                       | 5                                                              |              |
| Total Points |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  | 100                                                            |              |



| 4.           | Management of Change                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   | Possible Score                                         | Actual Score |
|--------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------|--------------|
| 4.1          | Does the facility have a written Management of Change procedure that must be followed whenever new facilities are added or changes are made to a process?<br><br>Are authorization procedures clearly stated and at an appropriate level?                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              | 9<br><br>5                                             |              |
| 4.2          | Do the following types of "changes" invoke the Management of Change procedure?<br><br>a. Physical changes to the facility, other than replacement in kind (expansions, equipment modifications, instrument or alarm system revisions, etc.).<br><br>b. Changes in process chemicals (feedstocks, catalysts, solvents, etc.).<br><br>c. Changes in process conditions (operating temperatures, pressures, production rates, etc.).<br><br>d. Significant changes in operating procedures (startup or shutdown sequences, unit staffing level or assignments, etc.).                                                                                                                                                                                                                     | <br><br>4<br><br>4<br><br>4<br><br>4                   |              |
| 4.3          | Is there a clear understanding at the facility of what constitutes a "temporary change?"<br><br>a. Does Management of Change handle temporary changes as well as permanent changes?<br><br>b. Are items that are installed as "temporary" tracked to ensure that they are either removed after a reasonable period of time or reclassified as permanent?                                                                                                                                                                                                                                                                                                                                                                                                                               | 5<br><br>4<br><br>5                                    |              |
| 4.4          | Do the Management of Change procedures specifically require the following actions whenever a change is made to a process?<br><br>a. Require an appropriate Process Hazard Analysis for the unit.<br><br>b. Update all affected operating procedures.<br><br>c. Update all affected maintenance programs and inspection schedules.<br><br>d. Modify P&IDs, statement of operating limits, Material Safety Data Sheets, and any other process safety information affected.<br><br>e. Notify all process and maintenance employees who work in the area of the change, and provide training as required.<br><br>f. Notify all contractors affected by the change.<br><br>g. Review the effect of the proposed change on all separate but interrelated upstream and downstream facilities. | <br><br>3<br><br>3<br><br>3<br><br>3<br><br>3<br><br>3 |              |
| 4.5          | When changes are made in the process or operating procedures, are there written procedures requiring that the impact of these changes on the equipment and materials of construction be reviewed to determine whether they will cause any increased rate of deterioration or failure, or will result in different failure mechanisms in the process equipment?                                                                                                                                                                                                                                                                                                                                                                                                                         | 10                                                     |              |
| 4.6          | When the equipment or materials of construction are changed through replacement or maintenance items, is there a system in place to formally review any metallurgical change to ensure that the new material is suitable for the process?                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              | 5                                                      |              |
| Total Points |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        | 80                                                     |              |

| 5. Operating Procedures |                                                                                                                                                    | Possible Score | Actual Score |
|-------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------|----------------|--------------|
| 5.1                     | Are written operating procedures available to operations and maintenance personnel in all units?                                                   | 10             |              |
|                         | Do the operating procedures clearly define the position of the person or persons responsible for operation of each applicable area?                | 5              |              |
| 5.2                     | Are the following operating considerations covered in all Standard Operating Procedures (SOPs)?                                                    |                |              |
|                         | a. Initial startup.                                                                                                                                | 2              |              |
|                         | b. Normal (as well as emergency) operation.                                                                                                        | 2              |              |
|                         | c. Normal shutdown.                                                                                                                                | 2              |              |
|                         | d.1. Emergency shutdown.                                                                                                                           | 2              |              |
|                         | d.2 Is the position of the person or persons who may initiate these procedures defined?                                                            | 2              |              |
|                         | e. Steps required to correct or avoid deviation from operating limits and consequences of the deviation.                                           | 2              |              |
|                         | f. Startup following a turnaround.                                                                                                                 | 2              |              |
|                         | g. Safety systems and their functions.                                                                                                             | 2              |              |
| 5.3                     | Are the following safety and health considerations covered in all SOPs for the chemicals used in the process?                                      |                |              |
|                         | a. Properties of, and hazards presented by, the chemicals.                                                                                         | 3              |              |
|                         | b. Precautions necessary to prevent exposure, including controls and personal protective equipment.                                                | 4              |              |
|                         | c. Control measures to be taken if physical contact occurs.                                                                                        | 3              |              |
| 5.4                     | Are the SOPs in the facility written in a clear and concise style to ensure effective comprehension and promote compliance of the users?           | 10             |              |
| 5.5                     | Are there adequate procedures for handover/transfer of information between shifts?                                                                 | 10             |              |
| 5.6                     | How frequently are operating procedures formally reviewed to ensure they reflect current operating practices and updated as required? (Choose one) |                |              |
|                         | _____ At least annually, or as changes occur                                                                                                       | 11             |              |
|                         | _____ Each two years                                                                                                                               | 6              |              |
|                         | _____ Only when major process changes occur                                                                                                        | 3              |              |
|                         | _____ No schedule has been established                                                                                                             | 0              |              |
| 5.7                     | How often is an unbiased evaluation made of the level of compliance with written operating procedures? (Choose one)                                |                |              |
|                         | _____ Every 6 months                                                                                                                               | 8              |              |
|                         | _____ Yearly                                                                                                                                       | 4              |              |
|                         | _____ Each 3 years                                                                                                                                 | 2              |              |
|                         | _____ Not Done                                                                                                                                     | 0              |              |
| Total Points            |                                                                                                                                                    | 80             |              |

| 6.           | Safe Work Practices                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               | Possible Score                                                                            | Actual Score |
|--------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------|--------------|
| 6.1          | <p>Have safe work practices been developed and implemented for employees and contractors to provide for the control of hazards during operation or maintenance, including:</p> <ul style="list-style-type: none"> <li>a. Hot work.</li> <li>b. Line breaking procedures.</li> <li>c. Lockout/tagout.</li> <li>d. Confined space entry.</li> <li>e. Opening process equipment or piping.</li> <li>f. Entrance into a facility by maintenance, contract, laboratory, or other support personnel.</li> <li>g. Vehicle entry.</li> <li>h. Crane lifts.</li> <li>i. Handling of particularly hazardous materials (toxic, radioactive, etc.).</li> <li>j. Inspection or maintenance of in-service equipment.</li> </ul> | <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p> |              |
| 6.2          | <p>Do all the safe work practices listed in 6.1 require a work authorization form or permit prior to initiating the activity?</p> <p>If so, do the permit procedures include the following features?</p> <ul style="list-style-type: none"> <li>a. Forms that adequately cover the subject area.</li> <li>b. Clear instructions denoting the number of copies issued and who receives each copy.</li> <li>c. Authority required for issuance.</li> <li>d. Sign-off procedure at completion of work.</li> <li>e. Procedure for extension or reissue after shift change.</li> </ul>                                                                                                                                 | <p>10</p> <p>1</p> <p>1</p> <p>1</p> <p>1</p> <p>1</p>                                    |              |
| 6.3          | Is formal training provided to persons issuing each of the above permits?                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         | 10                                                                                        |              |
| 6.4          | Are the affected employees trained in the above permit and procedure requirements?                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                | 10                                                                                        |              |
| 6.5          | <p>How often is an independent evaluation made (e.g., by Safety Department or similar group), with results communicated to appropriate management, to determine the extent of compliance with requirements for work permits and specialized procedures for major units within the organization? (Choose one)</p> <p>____ Every 3 months</p> <p>____ Every 6 months</p> <p>____ Yearly</p> <p>____ Not done</p>                                                                                                                                                                                                                                                                                                    | <p>8</p> <p>4</p> <p>2</p> <p>0</p>                                                       |              |
| 6.6          | <p>Is a procedure in place that requires that all work permit procedures and work rules be formally reviewed at least every three years and updated as required?</p> <p>Do records indicate that these reviews are being conducted on a timely basis?</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                         | <p>10</p> <p>5</p>                                                                        |              |
| 6.7          | <p>Have surveys been conducted to determine whether working environments are consistent with ergonomic standards?</p> <p>Either no deficiencies were found in the above survey, or if they were, are they being corrected?</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    | <p>4</p> <p>4</p>                                                                         |              |
| Total Points |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   | 85                                                                                        |              |

| 7.           | Training                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        | Possible Score             | Actual Score |
|--------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------|--------------|
| 7.1          | Is there a written procedure that defines the general training in site-wide safety procedures, work practices, etc., that a newly hired employee will receive?                                                                                                                                                                                                                                                                                                                                                                  | 10                         |              |
| 7.2          | Is there a written procedure that defines the amount and content of site-specific training, in addition to the general training provided in 7.1, that an employee newly assigned to an operations position will receive prior to assuming his duties?                                                                                                                                                                                                                                                                           | 10                         |              |
| 7.3          | Does the procedure described in 7.2 require that the training include the following?<br>a. An overview of the process and its specific safety and health hazards.<br>b. Training in all operating procedures.<br>c. Training on site-emergency procedures.<br>d. Emphasis on safety-related issues such as work permits, importance of interlocks and other safety systems, etc.<br>e. Safe work practices.<br>f. Appropriate basic skills.                                                                                     | 3<br>3<br>3<br>3<br>3<br>3 |              |
| 7.4          | At the completion of formal training of operations personnel, what method is used to verify that the employee understands the information presented? (Choose one)<br>____ Performance test followed by documented observation<br>____ Performance test only<br>____ Opinion of instructor<br>____ No verification                                                                                                                                                                                                               | 10<br>7<br>3<br>0          |              |
| 7.5          | How often are operations employees given formal refresher training? (Choose one)<br>____ At least once every three years<br>____ Only when major process changes occur<br>____ Never                                                                                                                                                                                                                                                                                                                                            | 10<br>5<br>0               |              |
| 7.6          | What is the average amount of training given to each operations employee per year, averaged over all grades? (Choose one)<br>____ 15 days/year or more<br>____ 11 to 14 days/year<br>____ 7 to 10 days/year<br>____ 3 to 6 days/year<br>____ Less than 3 days/year                                                                                                                                                                                                                                                              | 10<br>7<br>5<br>3<br>0     |              |
| 7.7          | Has a systematic approach (e.g., employee surveys, task analysis, etc.) been used to identify the training needs of all employees at the facility, including the training programs referred to in 7.1 and 7.2?<br>a. Have training programs been established for the identified needs?<br>b. Are training needs reviewed and updated periodically?                                                                                                                                                                              | 4<br>4<br>4                |              |
| 7.8          | Are the following features incorporated in the plant's formal training programs?<br>a. Qualifications for trainers have been established and are documented for each trainer.<br>b. Written lesson plans are used that have been reviewed and approved to ensure complete coverage of the topic.<br>c. Training aids and simulators are used where appropriate to permit "hands-on" training.<br>d. Records are maintained for each trainee showing the date of training and means used to verify that training was understood. | 5<br>5<br>5<br>5           |              |
| Total Points |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                 | 100                        |              |

| 8.  | Mechanical Integrity                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              | Possible Score                                        | Actual Score |
|-----|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------|--------------|
| 8.1 | <p>Has a written inspection plan for the process unit been developed that includes the following elements:</p> <ul style="list-style-type: none"> <li>a. All equipment needing inspection has been identified?</li> <li>b. The responsibilities to conduct the inspections have been assigned?</li> <li>c. Inspection frequencies have been established?</li> <li>d. The inspection methods and locations have been specified?</li> <li>e. Inspection reporting requirements have been defined?</li> </ul>                                                                                                                                                                                                                                                                                                                                                                        | <p>2</p> <p>2</p> <p>2</p> <p>2</p> <p>2</p>          |              |
| 8.2 | <p>Does the inspection plan referred to in 8.1 include a formal, external visual inspection program for all process units?</p> <ul style="list-style-type: none"> <li>a. Are all the following factors considered in the visual inspection program: the condition of the outside of equipment, insulation, painting/coatings, supports and attachments, and identifying mechanical damage, corrosion, vibration, leakage or improper components or repairs?</li> <li>b. Based on the inspection plan referred to in 8.1, do all pressure vessels in the unit receive such a visual external inspection at least every 5 years?</li> <li>c. Based on this inspection plan, do all on-site piping systems that handle volatile, flammable products, toxins, acids and caustics, and other similar materials receive a visual external inspection at least every 5 years?</li> </ul> | <p>2</p> <p>1</p> <p>2</p> <p>2</p>                   |              |
| 8.3 | Based on the inspection plan, do all pressure vessels in the unit receive an internal or detailed inspection using appropriate nondestructive examination procedures at least every 10 years?                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     | 5                                                     |              |
| 8.4 | <p>Has each item of process equipment been reviewed by appropriate personnel to identify the probable causes of deterioration or failure?</p> <ul style="list-style-type: none"> <li>a. Has this information been used to establish the inspection methods, locations, and frequencies and the preventive maintenance programs?</li> <li>b. Have defect limits been established, based on fitness for service considerations?</li> </ul>                                                                                                                                                                                                                                                                                                                                                                                                                                          | <p>5</p> <p>1</p> <p>1</p>                            |              |
| 8.5 | <p>Is a formal program for thickness measurements of piping as well as vessels being used?</p> <ul style="list-style-type: none"> <li>a. When the locations for thickness measurements are chosen, <ul style="list-style-type: none"> <li>1. Is the likelihood and consequence of failure a major factor?</li> <li>2. Is localized corrosion and erosion a consideration?</li> </ul> </li> <li>b. Are thickness measurement locations clearly marked on inspection drawings and on the vessel or piping system to allow repetitive measurements at precisely the same locations?</li> <li>c. Are thickness surveys up to date?</li> <li>d. Are the results used to predict remaining life and adjust future inspection frequency?</li> </ul>                                                                                                                                      | <p>3</p> <p>1</p> <p>1</p> <p>2</p> <p>2</p> <p>2</p> |              |
| 8.6 | <p>Has the maximum allowable working pressure (MAWP) been established for all piping systems, using applicable codes and current operating conditions?</p> <p>Are the MAWP calculations updated after each thickness measurement, using the latest wall thickness and corrosion rate?</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         | <p>3</p> <p>2</p>                                     |              |

|      |                                                                                                                                                                                                                            | Possible Score | Actual Score |
|------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------|--------------|
| 8.7  | Is there a written procedure that requires an appropriate level of review and authorization prior to any changes in inspection frequencies or methods and testing procedures?                                              | 5              |              |
| 8.8  | Have adequate inspection checklists been developed and are they being used?                                                                                                                                                | 3              |              |
|      | Are they periodically reviewed and updated as equipment or processes change?                                                                                                                                               | 2              |              |
| 8.9  | Are all inspections, tests and repairs performed on the process equipment being promptly documented?                                                                                                                       | 3              |              |
|      | Does the documentation include all of the following information?:                                                                                                                                                          | 3              |              |
|      | a. The date of the inspection.                                                                                                                                                                                             |                |              |
|      | b. The name of the person who performed the inspection.                                                                                                                                                                    |                |              |
|      | c. Identification of the equipment inspected.                                                                                                                                                                              |                |              |
|      | d. A description of the inspection or testing.                                                                                                                                                                             |                |              |
|      | e. The results of the inspection.                                                                                                                                                                                          |                |              |
|      | f. All recommendations resulting from the inspection.                                                                                                                                                                      |                |              |
|      | g. A date and description of all maintenance performed.                                                                                                                                                                    |                |              |
| 8.10 | Is there a written procedure requiring that all process equipment deficiencies identified during an inspection be corrected in a safe and timely manner and are they tracked and followed up to assure completion?         | 5              |              |
|      | a. Is a system used to help determine priorities for action?                                                                                                                                                               | 1              |              |
|      | b. If defects are noted, are decisions to continue to operate the equipment based on sound engineering assessments of fitness for service?                                                                                 | 2              |              |
| 8.11 | Is there a complete, up-to-date, central file for all inspection program information and reports?                                                                                                                          | 3              |              |
|      | Is this file information available to everyone who works with the process?                                                                                                                                                 | 2              |              |
| 8.12 | Have all employees involved in maintaining and inspecting the process equipment been trained in an overview of the process and its hazards?                                                                                | 5              |              |
| 8.13 | Have all employees involved in maintaining and inspecting the process equipment been trained in all procedures applicable to their job tasks to ensure that they can perform the job tasks in a safe and effective manner? | 3              |              |
|      | At completion of the training described above, are formal methods used to verify that the employee understands what he was trained on?                                                                                     | 2              |              |
| 8.14 | Are inspectors certified for performance in accordance with applicable industry codes and standards (e.g., API 510, 570 and 653)?                                                                                          | 5              |              |
| 8.15 | Are training programs conducted for contractors' employees where special skills or techniques unique to the unit or plant are required for these employees to perform the job safely?                                      | 5              |              |
| 8.16 | Has a schedule been established for the inspection or testing of all pressure relief valves in the unit?                                                                                                                   | 3              |              |
|      | a. Is the schedule being met?                                                                                                                                                                                              | 1              |              |
|      | b. Are all inspections and repairs fully documented?                                                                                                                                                                       | 1              |              |
|      | c. Are all repairs made by personnel fully trained and experienced in relief valve maintenance?                                                                                                                            | 1              |              |

|              |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     | Possible Score        | Actual Score |
|--------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------|--------------|
| 8.17         | Does the preventive maintenance program used at the facility meet the following criteria?<br><br>a. All safety-critical items and other key equipment, such as electrical switchgear and rotating equipment, are specifically addressed.<br>b. Check lists and inspection sheets are being used.<br>c. Work is being completed on time.<br>d. The program is continuously modified based on inspection feedback.<br>e. Repairs are identified, tracked and completed as a result of the PM program. | 1<br>1<br>1<br>1<br>1 |              |
| 8.18         | Does the facility have a quality assurance program for construction and maintenance to ensure that:<br><br>a. Proper materials of construction are used?<br>b. Fabrication and inspection procedures are proper?<br>c. Equipment is maintained in compliance with codes and standards?<br>d. Flanges are properly assembled and tightened?<br>e. Replacement and maintenance materials are properly specified, inspected and stored?                                                                | 1<br>1<br>1<br>1<br>1 |              |
| 8.19         | Is there a permanent and progressive record for all pressure vessels that includes all of the following?<br><br>a. Manufacturers' data reports and other pertinent data records.<br>b. Vessel identification numbers.<br>c. Relief valve information.<br>d. Results of all inspections, repairs, alterations, or re-ratings that have occurred to date.                                                                                                                                             | 5                     |              |
| 8.20         | Are systems in place, such as written requirements, supervisor sign off, sufficient to ensure that all design repair and alteration done on any pressure vessel or piping system be done in accordance with the code to which the item was built, or in-service repair and inspection code?                                                                                                                                                                                                         |                       |              |
| Total Points |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     | 120                   |              |

| 9. Pre-Startup Safety Review |                                                                                                                                                                                                                                                                                                                                                                                                                                                                        | Possible Score | Actual Score |
|------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------|--------------|
| 9.1                          | Does company policy require a formal Process Hazard Analysis at the conception and/or design stages of all new development, construction, and major modification projects?                                                                                                                                                                                                                                                                                             | 10             |              |
| 9.2                          | Is there a written procedure requiring that all of the following items have been accomplished before the startup of new or significantly modified facilities?<br><br>a. Written operating procedures have been issued.<br>b. Training has been completed for all personnel involved in the process.<br>c. Adequate maintenance, inspection, safety and emergency procedures are in place.<br>d. Any recommendations resulting from the formal PHA have been completed. | 10             |              |

|              |                                                                                                                                                                                                                | Possible Score | Actual Score |
|--------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------|--------------|
| 9.3          | Is there a written procedure requiring that all equipment be inspected prior to startup to confirm that it has been installed in accordance with the design specifications and manufacturer's recommendations? | 10             |              |
|              | a. Does the procedure require formal inspection reports at each appropriate stage of fabrication and construction?                                                                                             | 5              |              |
|              | b. Does the procedure define the corrective action and follow-up needed when deficiencies are found?                                                                                                           | 5              |              |
| 9.4          | In the pre-startup safety review, is it required that physical checks be made to confirm:                                                                                                                      |                |              |
|              | a. Leak tightness of all mechanical equipment prior to the introduction of highly hazardous chemicals to the process?                                                                                          | 5              |              |
|              | b. Proper operation of all control equipment prior to startup?                                                                                                                                                 | 5              |              |
|              | c. Proper installation and operation of all safety equipment (relief valves, interlocks, leak detection equipment, etc.)?                                                                                      | 5              |              |
| 9.5          | Is there a requirement to formally document the completion of the items in Questions 9.1, 9.2, 9.3, and 9.4 prior to startup, with a copy of the certification going to facility management?                   | 5              |              |
| Total Points |                                                                                                                                                                                                                | 60             |              |

| 10. Emergency Response |                                                                                                                                                                     | Possible Score | Actual Score |
|------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------|--------------|
| 10.1                   | Does the facility have an emergency plan in writing to address all probable emergencies?                                                                            | 10             |              |
| 10.2                   | Is there a requirement to formally review and update the emergency plan on a specified schedule?                                                                    |                |              |
|                        | a. Does the facility's Management of Change procedure include a requirement to consider possible impact on the facility emergency plan?                             | 2              |              |
|                        | b. Are the results of all new or updated PHA's reviewed to determine whether any newly identified hazards will necessitate a change in the facility emergency plan? | 2              |              |
| 10.3                   | Does the emergency plan include at least the following?                                                                                                             |                |              |
|                        | a. Procedures to designate one individual as Coordinator in an emergency situation, with a clear statement of his or her responsibilities.                          | 2              |              |
|                        | b. Emergency escape procedures and emergency escape route assignments.                                                                                              | 2              |              |
|                        | c. Procedures to be followed by employees who remain to perform critical plant operations before they evacuate.                                                     | 2              |              |
|                        | d. Procedures to account for all employees after emergency evacuation has been completed.                                                                           | 2              |              |
|                        | e. Rescue and medical duties for those employees who are to perform them.                                                                                           | 2              |              |
|                        | f. Preferred means of reporting fires and other emergencies.                                                                                                        | 2              |              |
|                        | g. Procedures for control of hazardous materials.                                                                                                                   | 2              |              |
|                        | h. A search and rescue plan.                                                                                                                                        | 2              |              |
|                        | i. An all-clear and re-entry procedure.                                                                                                                             | 2              |              |



|              |                                                                                                                                                                                                                                                                                                                                       | Possible Score       | Actual Score |
|--------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------|--------------|
| 10.4         | Has an emergency control center been designated for the facility?<br><br>Does it have the following minimum resources?<br><br>a. Emergency power source.<br><br>b. Adequate communication facilities.<br><br>c. Copies of P&IDs, SOPs, MSDS, Plot Plans, and other critical safety information for all process units at the facility. | 5<br><br>2<br>2<br>2 |              |
| 10.5         | Have persons been designated who can be contacted for further information or explanation of duties under the emergency plan?<br><br>Is this list of names posted in all appropriate locations (control rooms, security office, emergency control center, etc.)?                                                                       | 5<br><br>2           |              |
| 10.6         | Are regular drills conducted to evaluate and reinforce the emergency plan?                                                                                                                                                                                                                                                            | 10                   |              |
| Total Points |                                                                                                                                                                                                                                                                                                                                       | 65                   |              |

| 11.  | Incident Investigation                                                                                                                                                                                                                                                                                                                                                                                                              | Possible Score        | Actual Score |
|------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------|--------------|
| 11.1 | Is there a written incident/accident investigation procedure that includes both accidents and near misses?<br><br>Does the procedure require that findings and recommendations of investigations be addressed and resolved promptly?                                                                                                                                                                                                | 10<br><br>5           |              |
| 11.2 | Does the procedure require that the investigation team include:<br><br>a. A member trained in accident investigation techniques?<br><br>b. The line supervisor or someone equally familiar with the process?                                                                                                                                                                                                                        | 3<br><br>3            |              |
| 11.3 | Indicate whether the investigation procedure requires an investigation of the following items by the immediate supervisor with the results recorded on a standard form:<br><br>a. Fire and explosions.<br><br>b. Property losses at or above an established cost base.<br><br>c. All non-disabling injuries and occupational illnesses.<br><br>d. Hazardous substance discharge.<br><br>e. Other accidents/incidents (near-misses). | 2<br>2<br>2<br>2<br>2 |              |
| 11.4 | Is there a standard form for accident/incident investigation that includes the following information?:<br><br>a. Date of incident.<br><br>b. Date investigation began.<br><br>c. Description of the incident.<br><br>d. Underlying causes of the incident.<br><br>e. Evaluation of the potential severity and probable frequency of recurrence.                                                                                     | 2<br>2<br>2<br>2<br>2 |              |
|      | f. Recommendations to prevent recurrence.                                                                                                                                                                                                                                                                                                                                                                                           | 2                     |              |

|              |                                                                                                                                                                                                                                                   | Possible Score | Actual Score |
|--------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------|--------------|
| 11.5         | Based on a review of plant records, to what degree does it appear that the established incident investigation procedures are being followed?                                                                                                      | 5              |              |
| 11.6         | If the incident/accident involved a failure of a component or piece of equipment, are appropriate inspection or engineering people required to be involved in a failure analysis to identify the conditions or practices that caused the failure? | 10             |              |
| 11.7         | Are incident investigation reports reviewed with all affected personnel whose job tasks are relevant to the incident findings, including contract employees, where applicable?                                                                    | 5              |              |
| 11.8         | During the last 12-month period, have any incident or accident reports or report conclusions been transmitted to other sites that operate similar facilities within the company?                                                                  | 6              |              |
| 11.9         | Do the procedures for incident reporting and/or process hazard analysis require that the findings from all applicable incident reports be reviewed and incorporated into future PHAs?                                                             | 6              |              |
| Total Points |                                                                                                                                                                                                                                                   | 75             |              |

| 12. Contractors |                                                                                                                                                                                                                                                                                                                                                                                                                                                             | Possible Score       | Actual Score |
|-----------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------|--------------|
| 12.1            | Do contractor selection procedures include the following prior to awarding the contract?<br><ul style="list-style-type: none"> <li>a. A review of the contractor's existing safety and health programs.</li> <li>b. A review of the contractor's previous loss experience data.</li> <li>c. A review of the documentation of the experience and skills necessary to reasonably expect the contractor to perform the work safely and efficiently.</li> </ul> | <br>3<br>3<br>3      |              |
| 12.2            | Before the start of work, is the contract employer advised in writing of:<br><ul style="list-style-type: none"> <li>a. All known potential hazards of the process and of the contractor's work?</li> <li>b. Plant safe-work practices?</li> <li>c. Entry/access controls?</li> <li>d. All applicable provisions of the emergency response plan?</li> </ul>                                                                                                  | <br>2<br>2<br>2<br>2 |              |
| 12.3            | Are pre-job meetings held with contractors to review the scope of contract work activity plus the company's requirements for safety, quality assurance, and performance?                                                                                                                                                                                                                                                                                    | 9                    |              |
| 12.4            | Are periodic assessments performed to ensure that the contract employer is providing to his or her employees the training, instruction, monitoring, etc., required to ensure the contract employees abide by all facility safe-work practices?                                                                                                                                                                                                              | 9                    |              |
| 12.5            | Are all contractors who perform maintenance or repair, turnaround, major renovation or specialty work covered by all the procedures addressed in this section?                                                                                                                                                                                                                                                                                              | 10                   |              |
| Total Points    |                                                                                                                                                                                                                                                                                                                                                                                                                                                             | 45                   |              |

| 13.          | Management System Assessments                                                                                                                                                      | Possible Score       | Actual Score |
|--------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------|--------------|
| 13.1         | How often is a formal written assessment conducted of the facility's Process Safety Management system? (Choose one)<br><br>___ Every year<br>___ Every three years<br>___ Not done | 10<br><br>7<br><br>0 |              |
| 13.2         | Has an action plan been developed to meet program needs as indicated by the last assessment?                                                                                       | 10                   |              |
| 13.3         | Based on the most recent assessment, did the assessment team include people with the following skills:                                                                             |                      |              |
|              | a. Formal training in assessment techniques?                                                                                                                                       | 5                    |              |
|              | b. In-depth knowledge of the process being assessed?                                                                                                                               | 5                    |              |
| 13.4         | Based on a review of the most recent assessment, was the breadth and depth of the assessment appropriate for the facility?                                                         | 10                   |              |
| Total Points |                                                                                                                                                                                    | 40                   |              |

**APPENDIX E—OSHA 1910 AND EPA HAZARDOUS CHEMICALS LIST****List of Highly Hazardous Chemicals, Toxics and Reactives.  
(Mandatory) (OSHA 1910.119, Appendix A)**

This Appendix contains a listing of toxic and reactive highly hazardous chemicals that present a potential for a catastrophic event at or above the threshold quantity.

| CHEMICAL NAME                                      | CAS No. <sup>a</sup> | Total Quantity (lbs.) <sup>b</sup> |
|----------------------------------------------------|----------------------|------------------------------------|
| Acetaldehyde                                       | 75-07-0              | 2,500                              |
| Acrolein (2-Propenal)                              | 107-02-8             | 150                                |
| Acrylyl Chloride                                   | 814-68-6             | 250                                |
| Allyl Chloride                                     | 107-05-1             | 1,000                              |
| Allylamine                                         | 107-11-9             | 1,000                              |
| Alkylaluminums                                     | Varies               | 5,000                              |
| Ammonia, Anhydrous                                 | 7664-41-7            | 10,000                             |
| Ammonia solutions (> 44% ammonia by weight)        | 7664-41-7            | 15,000                             |
| Ammonium Perchlorate                               | 7790-98-9            | 7,500                              |
| Ammonium Permanganate                              | 7787-36-2            | 7,500                              |
| Arsine (also called Arsenic Hydride)               | 7784-42-1            | 100                                |
| Bis(Chloromethyl) Ether                            | 542-88-1             | 100                                |
| Boron Trichloride                                  | 10294-34-5           | 2,500                              |
| Boron Trifluoride                                  | 7637-07-2            | 250                                |
| Bromine                                            | 7726-95-6            | 1,500                              |
| Bromine Chloride                                   | 13863-41-7           | 1,500                              |
| Bromine Pentafluoride                              | 7789-30-2            | 2,500                              |
| Bromine Trifluoride                                | 7787-71-5            | 15,000                             |
| 3-Bromopropyne (also called Propargyl Bromide)     | 106-96-7             | 100                                |
| Butyl Hydroperoxide (Tertiary)                     | 75-91-2              | 5,000                              |
| Butyl Perbenzoate (Tertiary)                       | 614-45-9             | 7,500                              |
| Carbonyl Chloride (see Phosgene)                   | 75-44-5              | 100                                |
| Carbonyl Fluoride                                  | 353-50-4             | 2,500                              |
| Cellulose Nitrate (concentration > 12.6% nitrogen) | 9004-70-0            | 2,500                              |
| Chlorine                                           | 7782-50-5            | 1,500                              |
| Chlorine Dioxide                                   | 10049-04-4           | 1,000                              |
| Chlorine Pentafluoride                             | 13637-63-3           | 1,000                              |
| Chlorine Trifluoride                               | 7790-91-2            | 1,000                              |
| Chloromethyl Methyl Ether                          | 107-30-2             | 500                                |
| Chloropicrin                                       | 76-06-2              | 500                                |
| Chloropicrin and Methyl Bromide mixture            | None                 | 1,500                              |
| Chloropicrin and Methyl Chloride mixture           | None                 | 1,500                              |
| Cumene Hydroperoxide                               | 80-15-9              | 5,000                              |
| Cyanogen                                           | 460-19-5             | 2,500                              |
| Cyanogen Chloride                                  | 506-77-4             | 500                                |
| Cyanuric Fluoride                                  | 675-14-9             | 100                                |
| Diacetyl Peroxide (concentration > 70%)            | 10-22-5              | 5,000                              |
| Diazomethane                                       | 334-88-3             | 500                                |
| Dibenzoyl Peroxide                                 | 94-36-0              | 7,500                              |
| Diborane                                           | 19287-45-7           | 100                                |
| Dibutyl Peroxide (Tertiary)                        | 110-05-4             | 5,000                              |
| Dichloro Acetylene                                 | 7572-29-4            | 250                                |

<sup>a</sup>Chemical Abstract Service Number

<sup>b</sup>Threshold Quantity in Pounds (Amount necessary to be covered by this standard.)

| CHEMICAL NAME                                                                            | CAS No. <sup>a</sup> | Total Quantity (lbs.) <sup>b</sup> |
|------------------------------------------------------------------------------------------|----------------------|------------------------------------|
| Dichlorosilane                                                                           | 4109-96-0            | 2,500                              |
| Diethylzinc                                                                              | 57-20-0              | 10,000                             |
| Diisopropyl Peroxydicarbonate                                                            | 105-64-6             | 7,500                              |
| Dilauroyl Peroxide                                                                       | 105-74-8             | 7,500                              |
| Dimethyldichlorosilane                                                                   | 75-78-5              | 1,000                              |
| Dimethylhydrazine, 1,1-                                                                  | 57-14-7              | 1,000                              |
| Dimethylamine, Anhydrous                                                                 | 124-40-3             | 2,500                              |
| 2,4-Dinitroaniline                                                                       | 97-02-9              | 5,000                              |
| Ethyl Methyl Ketone Peroxide (also Methyl Ethyl Ketone Peroxide;<br>concentration > 60%) | 1338-23-4            | 5,000                              |
| ethyl Nitrite                                                                            | 109-95-5             | 5,000                              |
| Ethylamine                                                                               | 75-04-7              | 7,500                              |
| Ethylene Fluorohydrin                                                                    | 371-62-0             | 100                                |
| Ethylene Oxide                                                                           | 75-21-8              | 5,000                              |
| Ethyleneimine                                                                            | 151-56-4             | 1,000                              |
| Fluorine                                                                                 | 7782-41-4            | 1,000                              |
| Formaldehyde (Formalin)                                                                  | 50-00-0              | 1,000                              |
| Furan                                                                                    | 110-00-9             | 500                                |
| Hexafluoroacetone                                                                        | 684-16-2             | 5,000                              |
| Hydrochloric Acid, Anhydrous                                                             | 7647-01-0            | 5,000                              |
| Hydrofluoric Acid, Anhydrous                                                             | 7664-39-3            | 1,000                              |
| Hydrogen Bromide                                                                         | 10035-10-6           | 5,000                              |
| Hydrogen Chloride                                                                        | 7647-01-0            | 5,000                              |
| Hydrogen Cyanide, Anhydrous                                                              | 74-90-8              | 1,000                              |
| Hydrogen Fluoride                                                                        | 7664-39-3            | 1,000                              |
| Hydrogen Peroxide (52% by weight or greater)                                             | 7722-84-1            | 7,500                              |
| Hydrogen Selenide                                                                        | 7783-07-5            | 150                                |
| Hydrogen Sulfide                                                                         | 7783-06-4            | 1,500                              |
| Hydroxylamine                                                                            | 7803-49-8            | 2,500                              |
| Iron, Pentacarbonyl                                                                      | 13463-40-6           | 250                                |
| Isopropylamine                                                                           | 75-31-0              | 5,000                              |
| Ketene                                                                                   | 463-51-4             | 100                                |
| Methacrylaldehyde                                                                        | 78-85-3              | 1,000                              |
| Methacryloyl Chloride                                                                    | 920-46-7             | 150                                |
| Methacryloyloxyethyl Isocyanate                                                          | 30674-80-7           | 100                                |
| Methyl Acrylonitrile                                                                     | 126-98-7             | 250                                |
| Methylamine, Anhydrous                                                                   | 74-89-5              | 1,000                              |
| Methyl Bromide                                                                           | 74-83-9              | 2,500                              |
| Methyl Chloride                                                                          | 74-87-31             | 5,000                              |
| Methyl Chloroformate                                                                     | 79-22-1              | 500                                |
| Methyl Ethyl Ketone Peroxide (concentration > 60%)                                       | 1338-23-4            | 5,000                              |
| Methyl Fluoroacetate                                                                     | 453-18-9             | 100                                |
| Methyl Fluorosulfate                                                                     | 421-20-5             | 100                                |
| Methyl Hydrazine                                                                         | 60-34-4              | 100                                |
| Methyl Iodide                                                                            | 74-88-4              | 7,500                              |
| Methyl Isocyanate                                                                        | 624-83-9             | 250                                |
| Methyl Mercaptan                                                                         | 74-93-1              | 5,000                              |
| Methyl Vinyl Ketone                                                                      | 79-84-4              | 100                                |
| Methyltrichlorosilane                                                                    | 75-79-6              | 500                                |
| Nickel Carbonyl (Nickel Tetracarbonyl)                                                   | 13463-39-3           | 150                                |

<sup>a</sup>Chemical Abstract Service Number<sup>b</sup>Threshold Quantity in Pounds (Amount necessary to be covered by this standard.)

| CHEMICAL NAME                                                                                          | CAS No. <sup>a</sup> | Total Quantity (lbs.) <sup>b</sup> |
|--------------------------------------------------------------------------------------------------------|----------------------|------------------------------------|
| Nitric Acid (94.5% by weight or greater)                                                               | 7697-37-2            | 500                                |
| Nitric Oxide                                                                                           | 10102-43-9           | 250                                |
| Nitroaniline (para Nitroaniline)                                                                       | 100-01-6             | 5,000                              |
| Nitromethane                                                                                           | 75-52-5              | 2,500                              |
| Nitrogen Dioxide                                                                                       | 10102-44-0           | 250                                |
| Nitrogen Oxides (NO; NO <sub>2</sub> ; N <sub>2</sub> O <sub>4</sub> ; N <sub>2</sub> O <sub>3</sub> ) | 10102-44-0           | 250                                |
| Nitrogen Tetroxide (also called Nitrogen Peroxide)                                                     | 10544-72-6           | 250                                |
| Nitrogen Trifluoride                                                                                   | 7783-54-2            | 5,000                              |
| Nitrogen Trioxide                                                                                      | 10544-73-7           | 250                                |
| Oleum (65% to 80% by weight; also called Fuming Sulfuric Acid)                                         | 8014-94-7            | 1,000                              |
| Osmium Tetroxide                                                                                       | 20816-12-0           | 100                                |
| Oxygen Difluoride (Fluorine Monoxide)                                                                  | 7783-41-7            | 100                                |
| Ozone                                                                                                  | 10028-15-6           | 100                                |
| Pentaborane                                                                                            | 19624-22-7           | 100                                |
| Peracetic Acid (concentration > 60% Acetic Acid; also called Peroxyacetic Acid)                        | 79-21-0              | 1,000                              |
| Perchloric Acid (concentration > 60% by weight)                                                        | 7601-90-3            | 5,000                              |
| Perchloromethyl Mercaptan                                                                              | 594-42-3             | 150                                |
| Perchloryl Fluoride                                                                                    | 7616-94-6            | 5,000                              |
| Peroxyacetic Acid (concentration > 60% Acetic Acid; also called Peracetic Acid)                        | 79-21-0              | 1,000                              |
| Phosgene (also called Carbonyl Chloride)                                                               | 75-44-5              | 100                                |
| Phosphine (Hydrogen Phosphide)                                                                         | 7803-51-2            | 100                                |
| Phosphorus Oxychloride (also called Phosphoryl Chloride)                                               | 10025-87-3           | 1,000                              |
| Phosphorus Trichloride                                                                                 | 7719-12-2            | 1,000                              |
| Phosphoryl Chloride (also called Phosphorus Oxychloride)                                               | 10025-87-3           | 1,000                              |
| Propargyl Bromide                                                                                      | 106-96-7             | 100                                |
| Propyl Nitrate                                                                                         | 627-3-4              | 2,500                              |
| Sarin                                                                                                  | 107-44-8             | 100                                |
| Selenium Hexafluoride                                                                                  | 7783-79-1            | 1,000                              |
| Stibine (Antimony Hydride)                                                                             | 7803-52-3            | 500                                |
| Sulfur Dioxide (liquid)                                                                                | 7446-09-5            | 1,000                              |
| Sulfur Pentafluoride                                                                                   | 5714-22-7            | 250                                |
| Sulfur Tetrafluoride                                                                                   | 7783-60-0            | 250                                |
| Sulfur Trioxide (also called Sulfuric Anhydride)                                                       | 7446-11-9            | 1,000                              |
| Sulfuric Anhydride (also called Sulfur Trioxide)                                                       | 7446-11-9            | 1,000                              |
| Tellurium Hexafluoride                                                                                 | 7783-80-4            | 250                                |
| Tetrafluoroethylene                                                                                    | 116-14-3             | 5,000                              |
| Tetrafluorohydrazine                                                                                   | 10036-47-2           | 5,000                              |
| Tetramethyl Lead                                                                                       | 75-74-1              | 1,000                              |
| Thionyl Chloride                                                                                       | 7719-09-7            | 250                                |
| Trichloro (chloromethyl) Silane                                                                        | 1558-25-4            | 100                                |
| Trichloro (dichlorophenyl) Silane                                                                      | 27137-85-5           | 2,500                              |
| Trichlorosilane                                                                                        | 10025-78-2           | 5,000                              |
| Trifluorochloroethylene                                                                                | 79-38-9              | 10,000                             |
| Trimethoxysilane                                                                                       | 2487-90-3            | 1,500                              |

<sup>a</sup>Chemical Abstract Service Number<sup>b</sup>Threshold Quantity in Pounds (Amount necessary to be covered by this standard.)

Table E-1—List of Regulated Substances and Thresholds for Accidental Release Prevention—Requirements for Petitions under Section 112(r) of the Clean Air Act as Amended

| Chemical Name                                      | CAS No.    | Threshold Quantity (lb) | Basis for Listing |
|----------------------------------------------------|------------|-------------------------|-------------------|
| Acetone cyanohydrin                                | 75-86-5    | 5,000                   | (b)               |
| Acrolein                                           | 107-02-8   | 1,000                   | (b)               |
| Acrylonitrile                                      | 107-13-1   | 10,000                  | (b)               |
| Acrylyl chloride                                   | 814-68-6   | 1,000                   | (b)               |
| Allyl alcohol                                      | 107-18-6   | 5,000                   | (b)               |
| Allylamine                                         | 107-11-9   | 1,000                   | (b)               |
| Ammonia (anhydrous)                                | 7664-41-7  | 1,000                   | (a, b)            |
| Ammonia (aqueous solution, conc 20% or greater)    | 7664-41-7  | 5,000                   | (a, b)            |
| Aniline                                            | 62-53-3    | 5,000                   | (b)               |
| Antimony pentafluoride                             | 7783-70-2  | 1,000                   | (b)               |
| Arsenous trichloride                               | 7784-34-1  | 5,000                   | (b)               |
| Arsine                                             | 7784-42-1  | 500                     | (b)               |
| Benzal chloride                                    | 98-87-3    | 1,000                   | (b)               |
| Benzenamine, 3-(trifluoromethyl)-                  | 98-16-8    | 1,000                   | (b)               |
| Benzotrichloride                                   | 98-07-7    | 500                     | (b)               |
| Benzyl chloride                                    | 100-44-7   | 1,000                   | (b)               |
| Benzyl cyanide                                     | 140-29-4   | 1,000                   | (b)               |
| Boron trichloride                                  | 10294-34-5 | 1,000                   | (b)               |
| Boron trifluoride                                  | 7637-07-2  | 1,000                   | (b)               |
| Boron trifluoride compound with methyl ether (1:1) | 353-42-4   | 5,000                   | (b)               |
| Bromine                                            | 7726-95-6  | 1,000                   | (b)               |
| Carbon disulfide                                   | 75-15-0    | 10,000                  | (b)               |
| Chlorine                                           | 7782-50-5  | 1,000                   | (a, b)            |
| Chlorine dioxide                                   | 10049-04-4 | 500                     | (d)               |
| Chloroethanol                                      | 107-07-3   | 1,000                   | (b)               |
| Chloroform                                         | 67-66-3    | 10,000                  | (b)               |
| Chloromethyl ether                                 | 542-88-1   | 500                     | (b)               |
| Chloromethyl methyl ether                          | 107-30-2   | 1,000                   | (b)               |
| Crotonaldehyde                                     | 4170-30-3  | 10,000                  | (b)               |
| Crotonaldehyde, (E)-                               | 123-73-9   | 10,000                  | (b)               |
| Cyanogen chloride                                  | 506-77-4   | 1,000                   | (d)               |
| Trans-1,4-dichlorobutene                           | 110-57-6   | 1,000                   | (b)               |
| Dichloroethyl ether                                | 111-44-4   | 10,000                  | (b)               |
| Dimethyldichlorosilane                             | 75-78-5    | 1,000                   | (b)               |
| Dimethylhydrazine                                  | 57-14-7    | 5,000                   | (b)               |
| Dimethyl phosphorochloridothioate                  | 2524-03-0  | 1,000                   | (b)               |
| Epichlorohydrin                                    | 106-89-8   | 10,000                  | (b)               |
| Ethylenediamine                                    | 107-15-3   | 10,000                  | (b)               |
| Ethyleneimine                                      | 151-56-4   | 1,000                   | (b)               |
| Ethylene oxide                                     | 75-21-8    | 5,000                   | (a, b)            |
| Fluorine                                           | 7782-41-4  | 500                     | (b)               |
| Formaldehyde                                       | 50-00-0    | 500                     | (b)               |
| Formaldehyde cyanohydrin                           | 107-16-4   | 5,000                   | (b)               |
| Furan                                              | 110-00-9   | 1,000                   | (b)               |
| Hydrazine                                          | 302-01-2   | 5,000                   | (b)               |
| Hydrochloric acid (solution, conc. 25% or greater) | 7647-01-0  | 5,000                   | (e)               |
| Hydrocyanic acid                                   | 74-90-8    | 500                     | (a, b)            |
| Hydrogen chloride (anhydrous)                      | 7647-01-0  | 1,000                   | (a, b)            |
| Hydrogen fluoride                                  | 7664-39-3  | 500                     | (a, b)            |
| Hydrogen peroxide (conc. > 52%)                    | 7722-84-1  | 5,000                   | (b)               |
| Hydrogen selenide                                  | 7783-07-5  | 500                     | (b)               |
| Hydrogen sulfide                                   | 7783-06-4  | 1,000                   | (a, b)            |

Table E-1—List of Regulated Substances and Thresholds for Accidental Release Prevention—Requirements for Petitions under Section 112(r) of the Clean Air Act as Amended (Continued)

|                                           |            |        |        |
|-------------------------------------------|------------|--------|--------|
| Iron, pentacarbonyl-                      | 13463-40-6 | 500    | (b)    |
| Isobutyronitrile                          | 78-82-0    | 10,000 | (b)    |
| Isopropyl chloroformate                   | 108-23-6   | 5,000  | (b)    |
| Lactonitrile                              | 78-97-7    | 5,000  | (b)    |
| Methacrylonitrile                         | 126-98-7   | 1,000  | (b)    |
| Methyl bromide                            | 74-83-9    | 5,000  | (b)    |
| Methyl chloride                           | 74-87-3    | 10,000 | (a)    |
| Methyl chloroformate                      | 79-22-1    | 1,000  | (b)    |
| Methyl hydrazine                          | 60-34-4    | 5,000  | (b)    |
| Methyl isocyanate                         | 624-83-9   | 1,000  | (a, b) |
| Methyl mercaptan                          | 74-93-1    | 1,000  | (b)    |
| Methyl thiocyanate                        | 556-64-9   | 10,000 | (b)    |
| Methyltrichlorosilane                     | 75-79-6    | 1,000  | (b)    |
| Nickel carbonyl                           | 13463-39-3 | 500    | (b)    |
| Nitric acid                               | 7697-37-2  | 5,000  | (b)    |
| Nitric oxide                              | 10102-43-9 | 1,000  | (b)    |
| Nitrobenzene                              | 98-95-3    | 10,000 | (c)    |
| Parathion                                 | 56-38-2    | 1,000  | (c)    |
| Peracetic acid                            | 79-21-0    | 1,000  | (b)    |
| Perchloromethylmercaptan                  | 594-42-3   | 1,000  | (b)    |
| Phenol (liquid)                           | 108-95-2   | 10,000 | (c)    |
| Phosgene                                  | 75-44-5    | 500    | (a, b) |
| Phosphine                                 | 7803-51-2  | 1,000  | (b)    |
| Phosphorus oxychloride                    | 10025-87-3 | 1,000  | (b)    |
| Phosphorus trichloride                    | 7719-12-2  | 5,000  | (b)    |
| Piperidine                                | 110-89-4   | 5,000  | (b)    |
| Propionitrile                             | 107-12-0   | 1,000  | (b)    |
| Propyl chloroformate                      | 109-61-5   | 5,000  | (b)    |
| Propyleneimine                            | 75-55-8    | 10,000 | (b)    |
| Propylene oxide                           | 75-56-9    | 10,000 | (b)    |
| Pyridine, 2-methyl-5-vinyl-               | 140-76-1   | 1,000  | (b)    |
| Sulfur dioxide                            | 7446-09-5  | 1,000  | (a, b) |
| Sulfuric acid                             | 7664-93-9  | 5,000  | (c)    |
| Sulfur tetrafluoride                      | 7783-60-0  | 1,000  | (b)    |
| Sulfur trioxide                           | 7446-11-9  | 1,000  | (a, b) |
| Tetramethyllead                           | 75-74-1    | 1,000  | (b)    |
| Tetranitromethane                         | 509-14-8   | 1,000  | (b)    |
| Thiophenol                                | 108-98-5   | 1,000  | (b)    |
| Titanium tetrachloride                    | 7550-45-0  | 500    | (b)    |
| Toluene 2,4-diisocyanate                  | 584-84-9   | 1,000  | (a)    |
| Toluene 2,6-diisocyanate                  | 91-08-7    | 1,000  | (a)    |
| Toluene diisocyanate (unspecified isomer) | 26471-62-5 | 1,000  | (a)    |
| Trichloroethylsilane                      | 115-21-9   | 1,000  | (b)    |
| Trimethylchlorosilane                     | 75-77-4    | 1,000  | (b)    |
| Vinyl acetate monomer                     | 108-05-4   | 5,000  | (b)    |
| Vinyl chloride                            | 75-01-4    | 10,000 | (a)    |

## Basis for Listing:

- (a) Mandated for listing by Congress.
- (b) On EHS list, vapor pressure 0.5 mmHg or greater.
- (c) On EHS list, vapor pressure less than 0.5 mmHg, but has been involved in accidents resulting in death or injury.
- (d) Toxic gas.
- (e) Listed based on toxicity of hydrogen chloride, potential to release hydrogen chloride, and history of accidents.



Table E-2—List of Regulated Toxic Substances and Threshold Quantities for Accidental Release Prevention—CAS Number Order—100 Substances

| CAS No.  | Chemical Name                    | Threshold Quantity (lb) | Basis for Listing |
|----------|----------------------------------|-------------------------|-------------------|
| 50-00-0  | Formaldehyde                     | 500                     | (b)               |
| 56-38-2  | Parathion                        | 1,000                   | (c)               |
| 57-14-7  | Dimethylhydrazine                | 5,000                   | (b)               |
| 60-34-4  | Methyl hydrazine                 | 5,000                   | (b)               |
| 62-53-3  | Aniline                          | 5,000                   | (b)               |
| 67-66-3  | Chloroform                       | 10,000                  | (b)               |
| 74-83-9  | Methyl bromide                   | 5,000                   | (b)               |
| 74-87-3  | Methyl chloride                  | 10,000                  | (a)               |
| 74-90-8  | Hydrocyanic acid                 | 500                     | (a, b)            |
| 74-93-1  | Methyl mercaptan                 | 1,000                   | (b)               |
| 75-01-4  | Vinyl chloride                   | 10,000                  | (a)               |
| 75-15-0  | Carbon disulfide                 | 10,000                  | (b)               |
| 75-21-8  | Ethylene oxide                   | 5,000                   | (a, b)            |
| 75-44-5  | Phosgene                         | 500                     | (a, b)            |
| 75-55-8  | Propyleneimine                   | 10,000                  | (b)               |
| 75-56-9  | Propylene oxide                  | 10,000                  | (b)               |
| 75-74-1  | Tetramethyllead                  | 1,000                   | (b)               |
| 75-77-4  | Trimethylchlorosi lane           | 1,000                   | (b)               |
| 75-78-5  | Dimethyldichlorosi lane          | 1,000                   | (b)               |
| 75-79-6  | Methyltrichlorosi lane           | 1,000                   | (b)               |
| 75-86-5  | Acetone cyanohydrin              | 5,000                   | (b)               |
| 78-82-0  | Isobutyronitrile                 | 10,000                  | (b)               |
| 78-97-7  | Lactonitrile                     | 5,000                   | (b)               |
| 79-21-0  | Peracetic acid                   | 1,000                   | (b)               |
| 79-22-1  | Methyl chloroformate             | 1,000                   | (b)               |
| 91-08-7  | Toluene 2,6-diisocyanate         | 1,000                   | (a)               |
| 98-07-7  | Benzotrithloride                 | 500                     | (b)               |
| 98-16-8  | Benzenamine, 3-(trifluoromethyl) | 1,000                   | (b)               |
| 98-87-3  | Benzal chloride                  | 1,000                   | (b)               |
| 98-95-3  | Nitrobenzene                     | 10,000                  | (c)               |
| 100-44-7 | Benzyl chloride                  | 1,000                   | (b)               |
| 106-89-8 | Epichlorohydrin                  | 10,000                  | (b)               |
| 107-02-8 | Acrolein                         | 1,000                   | (b)               |
| 107-07-3 | Chloroethanol                    | 1,000                   | (b)               |
| 107-11-9 | Allylamine                       | 1,000                   | (b)               |
| 107-12-0 | Propionitrile                    | 1,000                   | (b)               |
| 107-16-4 | Formaldehyde cyanohydrin         | 5,000                   | (b)               |
| 107-18-6 | Allyl alcohol                    | 5,000                   | (b)               |
| 107-30-2 | Chloromethyl methyl ether        | 1,000                   | (b)               |
| 108-05-4 | Vinyl acetate monomer            | 5,000                   | (b)               |
| 108-23-6 | Isopropyl chloroformate          | 5,000                   | (b)               |
| 108-91-8 | Cyclohexylamine                  | 5,000                   | (b)               |
| 108-95-2 | Phenol (liquid)                  | 10,000                  | (c)               |
| 108-98-5 | Thiophenol                       | 1,000                   | (b)               |
| 109-61-5 | Propyl chloroformate             | 5,000                   | (b)               |
| 110-00-9 | Furan                            | 1,000                   | (b)               |
| 110-57-6 | Trans-1,4-dichlorobutene         | 1,000                   | (b)               |
| 110-89-4 | Piperidine                       | 5,000                   | (b)               |
| 111-44-4 | Dichloroethyl ether              | 10,000                  | (b)               |
| 115-21-9 | Trichloroethylsi lane            | 1,000                   | (b)               |
| 123-73-9 | Crotonaldehyde, (E)              | 10,000                  | (b)               |
| 126-98-7 | Methacrylonitrile                | 1,000                   | (b)               |

Table E-2—List of Regulated Toxic Substances and Threshold Quantities for Accidental Release Prevention—CAS Number Order—100 Substances (Continued)

| CAS No     | Chemical Name                                      | Threshold Quantity (lbs.) | Basis for Listing |
|------------|----------------------------------------------------|---------------------------|-------------------|
| 140-29-4   | Benzyl cyanide                                     | 1,000                     | (b)               |
| 140-76-1   | Pyridine, 2-methyl-5-vinyl                         | 1,000                     | (b)               |
| 151-56-4   | Ethyleneimine                                      | 1,000                     | (b)               |
| 302-01-2   | Hydrazine                                          | 5,000                     | (b)               |
| 353-42-4   | Boron trifluoride compound with methyl ether (1:1) | 5,000                     | (b)               |
| 506-77-4   | Cyanogen chloride                                  | 1,000                     | (d)               |
| 509-14-8   | Tetranitromethane                                  | 1,000                     | (b)               |
| 542-88-1   | Chloromethyl ether                                 | 500                       | (b)               |
| 556-64-9   | Methyl thiocyanate                                 | 10,000                    | (b)               |
| 584-84-9   | Toluene 2,4-diisocyanate                           | 1,000                     | (a)               |
| 594-42-3   | Perch-loromethylmer-captan                         | 1,000                     | (b)               |
| 624-83-9   | Methyl isocyanate                                  | 1,000                     | (a, b)            |
| 814-68-6   | Acrylyl chloride                                   | 1,000                     | (b)               |
| 2524-03-0  | Dimethylphosphorochloridothioate                   | 1,000                     | (b)               |
| 4170-30-3  | Crotonaldehyde                                     | 10,000                    | (b)               |
| 7446-09-5  | Sulfur dioxide                                     | 1,000                     | (a, b)            |
| 7446-11-9  | Sulfur trioxide                                    | 1,000                     | (a, b)            |
| 7550-45-0  | Titanium tetrachloride                             | 500                       | (b)               |
| 7637-07-2  | Boron trifluoride                                  | 1,000                     | (b)               |
| 7647-01-0  | Hydrogen chloride (anhydrous)                      | 1,000                     | (a, b)            |
| 7647-01-0  | Hydrochloric acid (solution, conc 25% or greater)  | 5,000                     | (e)               |
| 7664-39-3  | Hydrogen fluoride                                  | 500                       | (a, b)            |
| 7664-41-7  | Ammonia (anhydrous)                                | 1,000                     | (a, b)            |
| 7664-41-7  | Ammonia (aqueous solution, conc. 20% or greater)   | 5,000                     | (a, b)            |
| 7664-93-9  | Sulfuric acid                                      | 5,000                     | (c)               |
| 7697-37-2  | Nitric acid                                        | 5,000                     | (b)               |
| 7719-12-2  | Phosphorus trichloride                             | 5,000                     | (b)               |
| 7722-84-1  | Hydrogen peroxide (conc. > 52%)                    | 5,000                     | (b)               |
| 7726-95-6  | Bromine                                            | 1,000                     | (a, b)            |
| 7782-41-4  | Fluorine                                           | 500                       | (b)               |
| 7782-50-5  | Chlorine                                           | 1,000                     | (a, b)            |
| 7783-06-4  | Hydrogen sulfide                                   | 1,000                     | (a, b)            |
| 7783-07-5  | Hydrogen selenide                                  | 500                       | (b)               |
| 7783-60-0  | Sulfur tetrafluoride                               | 1,000                     | (b)               |
| 7783-70-2  | Antimony pentafluoride                             | 1,000                     | (b)               |
| 7784-34-1  | Arsenous trichloride                               | 5,000                     | (b)               |
| 7784-42-1  | Arsine                                             | 500                       | (b)               |
| 7803-51-2  | Phosphine                                          | 1,000                     | (b)               |
| 10025-87-3 | Phosphorus oxychloride                             | 1,000                     | (b)               |
| 10049-04-4 | Chlorine dioxide                                   | 500                       | (d)               |
| 10102-43-9 | Nitric oxide                                       | 1,000                     | (b)               |
| 10294-34-5 | Boron trichloride                                  | 1,000                     | (b)               |
| 13463-39-3 | Nickel carbonyl                                    | 500                       | (b)               |
| 13463-40-6 | Iron, pentacarbonyl                                | 500                       | (b)               |
| 19287-45-7 | Diborane                                           | 500                       | (b)               |
| 26471-62-5 | Toluene diisocyanate (unspecified isomer)          | 1,000                     | (a)               |

## Basis for Listing:

- (a) Mandated for listing by Congress.
- (b) On EHS list, vapor pressure 0.5 mmHg or greater.
- (c) On EHS list, vapor pressure less than 0.5 mmHg, but has been involved in accidents resulting in death or injury.
- (d) Toxic gas.
- (e) Listed based on toxicity of hydrogen chloride, potential to release hydrogen chloride, and history of accidents.

Table E-3—List of Regulated Flammable Substances and Threshold Quantities for Accidental Release Prevention

| Chemical Name         | CAS No.    | Threshold Quantity (lb) | Basis for Listing |
|-----------------------|------------|-------------------------|-------------------|
| Acetaldehyde          | 75-07-0    | 10,000                  | (g)               |
| Acetylene             | 74-86-2    | 10,000                  | (f)               |
| Bromotrifluorethylene | 598-73-2   | 10,000                  | (f)               |
| 1,3-Butadiene         | 106-99-0   | 10,000                  | (f)               |
| Butane                | 106-97-8   | 10,000                  | (f)               |
| 1-Butene              | 106-98-9   | 10,000                  | (f)               |
| 2-Butene              | 107-01-7   | 10,000                  | (f)               |
| Butene                | 25167-67-3 | 10,000                  | (f)               |
| 2-Butene-cis          | 590-18-1   | 10,000                  | (f)               |
| 2-Butene-trans        | 624-64-6   | 10,000                  | (f)               |
| Carbon oxysulfide     | 463-58-1   | 10,000                  | (f)               |
| Chlorine monoxide     | 7791-21-1  | 10,000                  | (f)               |
| 2-Chloropropylene     | 557-98-2   | 10,000                  | (g)               |
| 1-Chloropropylene     | 590-21-6   | 10,000                  | (g)               |
| Cyanogen              | 460-19-5   | 10,000                  | (f)               |
| Cyclopropane          | 75-19-4    | 10,000                  | (f)               |
| Dichlorosilane        | 4109-96-0  | 10,000                  | (f)               |
| Difluoroethane        | 75-37-6    | 10,000                  | (f)               |
| Dimethylamine         | 124-40-3   | 10,000                  | (f)               |
| 2,2-Dimethylpropane   | 463-82-1   | 10,000                  | (f)               |
| Ethane                | 74-84-0    | 10,000                  | (f)               |
| Ethyl acetylene       | 107-00-6   | 10,000                  | (f)               |
| Ethylamine            | 75-04-7    | 10,000                  | (f)               |
| Ethyl chloride        | 75-00-3    | 10,000                  | (f)               |
| Ethylene              | 74-85-1    | 10,000                  | (f)               |
| Ethyl ether           | 60-29-7    | 10,000                  | (g)               |
| Ethyl mercaptan       | 75-08-1    | 10,000                  | (g)               |
| Ethyl nitrite         | 109-95-5   | 10,000                  | (f)               |
| Hydrogen              | 1333-74-0  | 10,000                  | (f)               |
| Isobutane             | 75-28-5    | 10,000                  | (f)               |
| Isopentane            | 78-78-4    | 10,000                  | (g)               |
| Isoprene              | 78-79-5    | 10,000                  | (g)               |
| Isopropylamine        | 75-31-0    | 10,000                  | (g)               |
| Isopropyl chloride    | 75-29-6    | 10,000                  | (g)               |
| Methane               | 74-82-8    | 10,000                  | (f)               |
| Methylamine           | 74-89-5    | 10,000                  | (f)               |
| Methyl ether          | 115-10-6   | 10,000                  | (f)               |
| Methyl formate        | 107-31-3   | 10,000                  | (g)               |
| 2-Methylpropene       | 115-11-7   | 10,000                  | (f)               |

Table E-3—List of Regulated Flammable Substances and Threshold Quantities for  
Accidental Release Prevention (Continued)

| Chemical Name            | CAS No.    | Threshold Quantity (lb) | Basis for Listing |
|--------------------------|------------|-------------------------|-------------------|
| 1,3-Pentadiene           | 504-60-9   | 10,000                  | (f)               |
| Pentane                  | 109-66-0   | 10,000                  | (g)               |
| 1-Pentene                | 109-67-1   | 10,000                  | (g)               |
| 2-Pentene, (E)-          | 646-04-8   | 10,000                  | (g)               |
| 2-Pentene, (Z)-          | 627-20-3   | 10,000                  | (g)               |
| Propadiene               | 463-49-0   | 10,000                  | (f)               |
| Propane                  | 74-98-6    | 10,000                  | (f)               |
| Propylene                | 115-07-1   | 10,000                  | (f)               |
| Propyne                  | 74-99-7    | 10,000                  | (f)               |
| Silane                   | 7803-62-5  | 10,000                  | (f)               |
| Tetrafluoroethylene      | 116-14-3   | 10,000                  | (f)               |
| Tetramethylsilane        | 75-76-3    | 10,000                  | (g)               |
| Trichlorosilane          | 10025-78-2 | 10,000                  | (g)               |
| Trifluoro-chloroethylene | 79-38-9    | 10,000                  | (f)               |
| Trimethylamine           | 75-50-3    | 10,000                  | (f)               |
| Vinyl acetylene          | 689-97-4   | 10,000                  | (f)               |
| Vinyl ethyl ether        | 109-92-2   | 10,000                  | (g)               |
| Vinyl fluoride           | 75-02-5    | 10,000                  | (f)               |
| Vinylidene chloride      | 75-35-4    | 10,000                  | (g)               |
| Vinylidene fluoride      | 75-38-7    | 10,000                  | (f)               |
| Vinyl methyl ether       | 107-25-5   | 10,000                  | (f)               |

## Basis for Listing:

(f) Flammable gas.

(g) Volatile flammable liquid.

Table E-4—List of Regulated Flammable Substances and Threshold Quantities for Accidental Release Prevention—CAS Number Order—62 Substances

| CAS No.  | Chemical Name           | Threshold Quantity (lb) | Basis for Listing |
|----------|-------------------------|-------------------------|-------------------|
| 60-29-7  | Ethyl ether             | 10,000                  | (g)               |
| 74-82-8  | Methane                 | 10,000                  | (f)               |
| 74-84-0  | Ethane                  | 10,000                  | (f)               |
| 74-85-1  | Ethylene                | 10,000                  | (f)               |
| 74-86-2  | Acetylene               | 10,000                  | (f)               |
| 74-89-5  | Methylamine             | 10,000                  | (f)               |
| 74-98-6  | Propane                 | 10,000                  | (f)               |
| 74-99-7  | Propyne                 | 10,000                  | (f)               |
| 75-00-3  | Ethyl chloride          | 10,000                  | (f)               |
| 75-02-5  | Vinyl fluoride          | 10,000                  | (f)               |
| 75-04-7  | Ethylamine              | 10,000                  | (f)               |
| 75-07-0  | Acetaldehyde            | 10,000                  | (g)               |
| 75-08-1  | Ethyl mercaptan         | 10,000                  | (g)               |
| 75-19-4  | Cyclopropane            | 10,000                  | (f)               |
| 75-28-5  | Isobutane               | 10,000                  | (f)               |
| 75-29-6  | Isopropyl chloride      | 10,000                  | (g)               |
| 75-31-0  | Isopropylamine          | 10,000                  | (g)               |
| 75-35-4  | Vinylidene chloride     | 10,000                  | (g)               |
| 75-37-6  | Difluoroethane          | 10,000                  | (f)               |
| 75-38-7  | Vinylidene fluoride     | 10,000                  | (f)               |
| 75-50-3  | Trimethylamine          | 10,000                  | (f)               |
| 75-76-3  | Tetramethylsilane       | 10,000                  | (g)               |
| 78-78-4  | Isopentane              | 10,000                  | (g)               |
| 78-79-5  | Isoprene                | 10,000                  | (g)               |
| 79-38-9  | Trifluorochloroethylene | 10,000                  | (f)               |
| 106-97-8 | Butane                  | 10,000                  | (f)               |
| 106-98-9 | 1-Butene                | 10,000                  | (f)               |
| 106-99-0 | 1,3-Butadiene           | 10,000                  | (f)               |
| 107-00-6 | Ethyl acetylene         | 10,000                  | (f)               |
| 107-01-7 | 2-Butene                | 10,000                  | (f)               |
| 107-25-5 | Vinyl methyl ether      | 10,000                  | (f)               |
| 107-31-3 | Methyl formate          | 10,000                  | (g)               |
| 109-66-0 | Pentane                 | 10,000                  | (g)               |
| 109-67-1 | 1-Pentene               | 10,000                  | (g)               |
| 109-92-2 | Vinyl ethyl ether       | 10,000                  | (g)               |
| 109-95-5 | Ethyl nitrite           | 10,000                  | (f)               |
| 115-11-7 | 2-Methylpropene         | 10,000                  | (f)               |
| 116-14-3 | Tetrafluoroethylene     | 10,000                  | (f)               |
| 124-40-3 | Dimethylamine           | 10,000                  | (f)               |

Table E-4—List of Regulated Flammable Substances and Threshold Quantities for  
Accidental Release Prevention—CAS Number Order—62 Substances (Continued)

| CAS No.    | Chemical Name         | Threshold Quantity (lb) | Basis for Listing |
|------------|-----------------------|-------------------------|-------------------|
| 460-19-5   | Cyanogen              | 10,000                  | (f)               |
| 463-49-0   | Propadiene            | 10,000                  | (f)               |
| 463-58-1   | Carbon oxysulfide     | 10,000                  | (f)               |
| 463-82-1   | 2,2-Dimethylpropane   | 10,000                  | (f)               |
| 504-60-9   | 1,3-Pentadiene        | 10,000                  | (f)               |
| 557-98-2   | 2-Chloropropylene     | 10,000                  | (g)               |
| 563-45-1   | 3-Methyl-1-butene     | 10,000                  | (f)               |
| 563-46-2   | 2-Methyl-1-butene     | 10,000                  | (g)               |
| 590-18-1   | 2-Butene-cis          | 10,000                  | (f)               |
| 590-21-6   | 1-Chloropropylene     | 10,000                  | (g)               |
| 598-73-2   | Bromotrifluorethylene | 10,000                  | (f)               |
| 624-64-6   | 2-Butene-trans        | 10,000                  | (f)               |
| 627-20-3   | 2-Pentene, (Z)        | 10,000                  | (g)               |
| 646-04-8   | 2-Pentene, (E)        | 10,000                  | (g)               |
| 689-97-4   | Vinyl acetylene       | 10,000                  | (f)               |
| 1333-74-0  | Hydrogen              | 10,000                  | (f)               |
| 4109-96-0  | Dichlorosilane        | 10,000                  | (f)               |
| 7791-21-1  | Chlorine monoxide     | 10,000                  | (f)               |
| 7803-62-5  | Silane                | 10,000                  | (f)               |
| 10025-78-2 | Trichlorosilane       | 10,000                  | (g)               |
| 25167-67-3 | Butene                | 10,000                  | (f)               |

**Basis for Listing:**

(f) Flammable gas.

(g) Volatile flammable liquid.

## APPENDIX F—COMPARISON OF API AND ASME RISK-BASED INSPECTION

### F.1 Summary

This appendix summarizes the differences and similarities between the API Risk-Based Inspection Base Resource Document (BRD) and the ASME documents. The ASME documents reviewed were:

- Volume 1: General Document.
- Volume 2: Part 1. Light Water Reactor (LWR) Nuclear Power Plant Components.
- Volume 3: Fossil Fuel Fired Electric Power Generating Station Applications.

There are no philosophical differences between the API and the ASME approaches to Risk-Based Inspection; however, the final documents from the projects are notably different. The differences arise from the different scopes and goals of the two projects. The ASME projects were research efforts to determine risk-based methods for developing guidelines for inspection. The API project was intended to develop usable tools and methodologies that are understandable at a plant inspection level. The API project built upon the methods outlined in the ASME documents, but with considerable simplification where appropriate.

#### F.1.1 API RBI

The API BRD aims to be understandable and usable at the plant staff level. Application tools are needed (and are under development) to fully gain the benefit of risk based inspection, since even with the use of simplified models, there is a large database to be manipulated in a typical refinery or chemical plant. The BRD provides a good start to demonstrate the feasibility and value of the technology.

#### F.1.2 ASME RBI

The ASME effort aims to the highest levels of technical development, since it is intended to be a research project. This approach provides much value to others who wish to develop applications using these methods, however, the technology as presented in the ASME documents is understandable and usable only by integrated team of high level specialists. The ASME documents set high standards for future RBI development.

### F.2 Scope

#### F.2.1 API RBI

The API BRD was intended to develop usable tools and methodologies that are understandable at a plant inspection level. The project attempted to identify the limitations of the techniques used due to simplification of complex models,

while identifying opportunities for increased levels of sophistication where appropriate.

#### F.2.2 ASME RBI

The ASME projects were research efforts to determine risk based methods for developing guidelines for inspection. They did not necessarily develop those guidelines. The ASME approach considers and includes all levels of complexity:

- a. Technical.
- b. Component level.
- c. Fault/Event Tree analysis.
- d. Decision tree analysis.

### F.3 Qualitative Risk-Based Inspection

Both the API and ASME documents use qualitative and quantitative approaches to Risk-Based Inspection, although not necessarily in the same fashion. The ASME matrix is shown in Figure F-1.

#### F.3.1 API RBI

In the BRD, the qualitative approach is intended for use as a screening tool at the operating unit level. This will allow the user to quickly focus on those areas of the plant that have the highest contribution to risk. The approach is intended to be easy to use:

- a. Adds factors contributing to high risk.
- b. Subtracts factors contributing to risk management.

The results are presented in a 5 x 5 matrix of likelihood and consequence. This approach can be extended to the equipment item level, and a current project is underway for this development (Phase 2).

#### F.3.2 ASME RBI

The ASME approach to qualitative risk assessment can be extended to the component level if desired. In the ASME approach, "qualitative" means "judgmental", i.e. based on the opinions of experts. Several methods for gleaning these opinions are presented:

- a. FMEA (Failure Modes & Effects Analysis).
- b. HAZOP (Hazard & Operability Study).
- c. FTA (Fault Tree Analysis).
- d. MLD (Master Logic Diagram).
- e. What-if (Question sets).

Similar to the API approach, qualitative analysis results are presented in a 5 x 5 matrix.

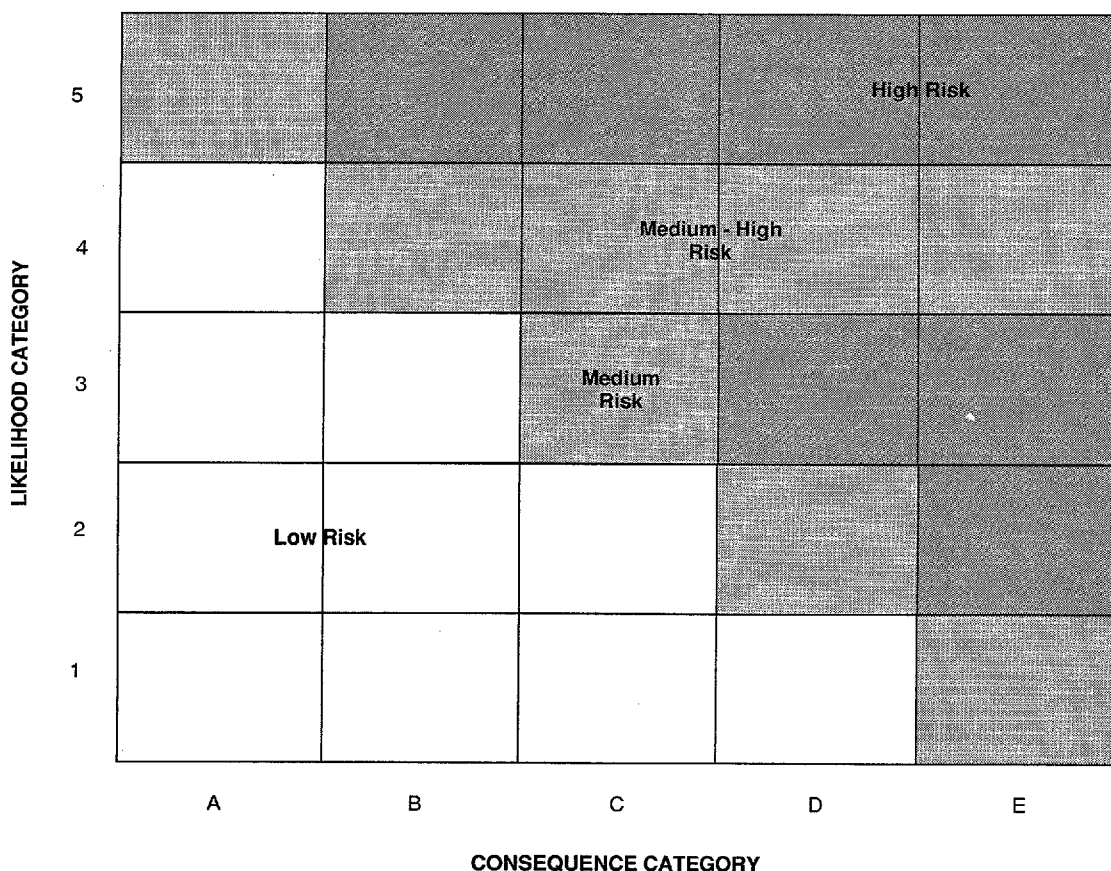


Figure F-1—ASME Qualitative Risk Matrix

The API matrix is shown in Figure F-2. Note that the shaded risk categories are skewed to account for the effects of risk aversion in the face of high consequences.

## F.4 Quantitative Risk-Based Inspection

### F.4.1 LIKELIHOOD OF FAILURE

#### F.4.1.1 API RBI

The API BRD uses a database of “generic” failure frequencies to establish base failure rates (events/yr) of different types of equipment common to the process industries. This approach has the advantage of providing a starting point for the application of RBI, but has the disadvantage that the database is not specific to any one type of industry. These “generic” frequencies are modified to account for various damage mechanisms using Probabilistic Structural Mechanics to evaluate the effect of varying degrees of damage on the probability of failure. Simplified mechanistic models are used to match the available data. The API approach uses a Bayesian updating technique to account for the reduction in proba-

bility of failure due to inspection based on the effectiveness of the inspection technique at finding the damage before failure.

#### F.4.1.2 ASME RBI

The ASME approach is illustrated in the referenced documents by the use of historical databases that are available for the Power industries. This greatly simplifies the approach if such data is available. The ASME documents also illustrate the use of Probabilistic Structural Mechanics (referred to as Structural Reliability and Risk Assessment, SRRA in the ASME documents). The illustrations of these techniques in the ASME documents in each case use the same demonstration: fatigue crack growth evaluated via rigorous elastic plastic fracture mechanics. This illustration is used because there are available models for crack growth, probability of detection, and probabilistic evaluation of the impact of the damage on structural reliability (probability of failure). However, the ASME approach does not address how to proceed in the absence of such models and data, except to rely on expert judgment of the POF in determined in a formal method.



|                      |   |                    |   |             |   |   |
|----------------------|---|--------------------|---|-------------|---|---|
| LIKELIHOOD CATEGORY  | 5 | Medium - High Risk |   | High Risk   |   |   |
|                      | 4 |                    |   |             |   |   |
|                      | 3 |                    |   |             |   |   |
|                      | 2 | Low Risk           |   | Medium Risk |   |   |
|                      | 1 |                    |   |             |   |   |
|                      |   | A                  | B | C           | D | E |
| CONSEQUENCE CATEGORY |   |                    |   |             |   |   |

Figure F-2—API Qualitative Risk Matrix

## F.4.2 CONSEQUENCES

### F.4.2.1 API RBI

The API BRD provides methods to quantify any of the following types of consequences:

- Flammable/Explosive.
- Toxicity.
- Environmental.
- Business Interruption.

The calculations are based on technical models of release scenarios.

### F.4.2.2 ASME RBI

The ASME approach uses various techniques for determination of consequences. For LWR nuclear power plants, the consequences are expressed as likelihood of core damage per event. The actual modeling of release scenarios is not attempted in this case. For fossil-fuel-fired power plants (FFFPP), the consequences are taken directly from an industry database giving the cost of purchased replacement power for given failure events. The use of Fault Trees/Event Trees

for determination of consequences in the fossil fuel fired plant case is provided as a demonstration of the techniques, but is extremely complex.

## F.4.3 QUANTITATIVE RISK ASSESSMENT

### F.4.3.1 API RBI

The final results from the API BRD present the risk as one or more of the following measures:

- Business Interruption (\$/yr).
- Equipment Damage (square feet/yr).
- Health Effects (square feet/yr).
- Environmental impact (\$/yr).

### F.4.3.2 ASME RBI

The final results from the ASME documents present the risk as one or more of the following measures:

- Likelihood of Core Damage per year.
- Economic Loss (FFFPP) (\$/yr).
- Casualties—FFFPP (Small—result of boiler rupture).

## F.5 Conclusions

The ASME research studies present the groundwork necessary to develop Risk-Based Inspection Guidelines, but do not actually provide such guidelines. The API BRD project builds

upon the earlier ASME efforts to develop usable tools that can provide the benefits of Risk-Based Inspection with a reasonable expenditure of effort.

## APPENDIX G—THINNING TECHNICAL MODULE

### G.1 Scope

This module establishes a technical module subfactor (likelihood of failure modifier) for process equipment subject to damage by mechanisms that result in thinning. General thinning and localized thinning (which includes pitting and erosion-corrosion) are within the scope of the module. If thinning rates have not been established from thickness inspection data, Supplements are available in this module to provide conservative estimates of thinning rates for damage mechanisms that result in thinning. Expert advice may also be used to establish expected rates of thinning in the absence of measured data.

### G.2 Technical Module Screening Questions

There are no screening questions to bypass the Technical Module on thinning. All equipment must enter this Technical Module.

### G.3 Basic Data

#### G.3.1 REQUIRED DATA

The basic data listed in Table G-1 are the minimum required to determine a technical module subfactor for thinning when a corrosion rate has been established by one or more effective inspections.

#### G.3.2 ADDITIONAL DATA

If a corrosion rate has not been established on the basis of thickness measurements obtained during one or more effective inspections, the steps in Table G-2 will be required to determine which thinning mechanisms are potentially active and to determine estimated corrosion rates.

### G.4 Basic Assumptions

This Technical Module assumes that the thinning mechanism has resulted in an average rate of thinning over the time period defined in the basic data that is fairly constant. The likelihood of failure is estimated by examining the possibility that the rate of thinning is greater than what is expected. The likelihood of these higher rates is determined by the amount of inspection and on-line monitoring that has been performed. The more thorough the inspection, and the greater the number of inspections and continued use of on-line monitoring, the less likely is the chance that the rate of thinning is greater than anticipated.

This Technical Module assumes that thinning would eventually result in failure by ductile overload. The likelihood of

failure is determined via reliability index methods for the limit state function given in Table G-3.

### G.5 Determination of Technical Module Subfactors

A flow chart of the steps required to determine the technical module subfactors for thinning is presented in Figure G-1. These steps are discussed below, along with the required tables.

#### G.5.1 DETERMINATION OF CORROSION RATE

The corrosion rate should be calculated from thickness data available from equipment inspection(s). If a calculated corrosion rate is available, it should be used in the determination of  $ar/t$  (proceed to F.5.2).

If a calculated corrosion rate is not available, estimated corrosion rates should be determined for each potential thinning mechanism using the supplements to this Technical Module. Screening questions are used to determine which of the thinning mechanism sections apply. These applicable sections will be entered to determine conservative estimated corrosion rates for possible thinning mechanisms. The estimated corrosion rate will then be used to determine  $ar/t$ . Alternatively, expert advice may be used to establish the maximum expected corrosion rate to be used to determine  $ar/t$ .

The screening questions listed in Table G-4 are used to select the applicable thinning mechanism.

#### G.5.2 CALCULATION OF $AR/T$

Calculate  $ar/t$  from the time ( $a$ ), corrosion rate ( $r$ ), and thickness ( $t$ ) data outlined in Table G-1. This number is equivalent to the fraction of wall loss due to thinning.

#### G.5.3 DETERMINATION OF TYPE OF THINNING

The results of effective inspections that have been performed on the equipment/piping should be used to designate the type of thinning (i.e., general versus localized). If this information is not known, then Table G-5 lists the type of thinning (general or localized) expected for various thinning mechanisms. If both general and localized thinning mechanisms are possible, then designate the type of thinning as localized. The type of thinning designated will be used to determine the effectiveness of inspection performed.

#### G.5.4 INSPECTION EFFECTIVENESS CATEGORY

Inspections are ranked according to their expected effectiveness at detecting thinning and correctly predicting the rate of thinning. The actual effectiveness of a given inspection technique depends on the characteristics of the thinning mechanism, (i.e., whether it is general or localized).

Table G-1—Basic Data Required for Thinning Analysis (Corrosion Rate Established)

| Basic Data                                                                                        | Comments                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
|---------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Thickness (inches)                                                                                | The actual measured thickness upon being placed in the current service, or the minimum construction thickness. The thickness used must be the thickness at the beginning of the time in service reported below.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| Time (years)                                                                                      | The number of years that the equipment has been exposed to the current process conditions that produced the corrosion rate used below. The default is the equipment age. However, if the corrosion rate changed significantly, perhaps as a result of changes in process conditions, the time period and the thickness should be adjusted accordingly. The time period will be from the time of the change, and the thickness will be the minimum wall thickness at the time of the change (which may be different from the original wall thickness).                                                                                                                                                                                                                                                                                               |
| Corrosion Allowance (inches)                                                                      | The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current service.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| Corrosion Rate (inches/year)                                                                      | The current rate of thinning calculated from thickness data, if available. Corrosion rates calculated from thickness data typically vary from one inspection to another. These variations may be due to variations in the wall thickness, or they may indicate a change in the actual corrosion rate. If the "short term" rate (calculated from the difference between the current thickness and the previous thickness) is significantly different from the "long term" rate (calculated from the difference between the current thickness and the original thickness), the equipment can be evaluated using the short term rate, but the appropriate time and thickness must be used. If the corrosion rate has not been established by inspection, estimated corrosion rates may be determined from the applicable Supplements or expert advice. |
| Thinning Type<br>(General or Localized)                                                           | Determine whether the thinning is general or localized for inspection results of effective inspections. General corrosion is defined as affecting more than 10% of the surface area and the wall thickness variation is less than 50 mils. Localized corrosion is defined as affecting less than 10% of the surface area or a wall thickness variation greater than 50 mils.                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| Operating Temperature (°F)                                                                        | The highest expected operating temperature expected during operation (consider normal and unusual operating conditions).                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| Operating Pressure (psi)                                                                          | The highest expected operating pressure (may be the relief valve set pressure unless pressures that high are unlikely).                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| MAWP (psi)                                                                                        | The pressure used to determine the minimum allowable wall thickness. If MAWP is not available, design pressure may be used for this input.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
| Inspection Effectiveness Category<br>(Highly, Usually, Fairly, Poorly, or Ineffective)            | The effectiveness category of each inspection that has been performed on the equipment during the time period (specified above). See Tables TM1.6A, B, and TM1.11 for guidelines to assign inspection effectiveness categories for general thinning, localized thinning, and CUI, respectively.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| Number of Inspections                                                                             | The number of inspections in each effectiveness category that have been performed during the time period (specified above).                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
| On-Line Monitoring<br>(Coupons, Probes, Process Variables, or Combinations)                       | The types of proactive on-line monitoring methods or tools employed, such as corrosion probes, coupons, process variables, etc.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| Thinning Mechanism                                                                                | If credit is to be taken for on-line monitoring, the potential thinning mechanisms must be known. Consult a knowledgeable materials/corrosion engineer for this information.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| Material of Construction<br>(Carbon steel, Low Alloy Steel, other Stainless Steel, or High Alloy) | The material of construction of the equipment/piping.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| Presence of Injection/Mix Point<br>(Yes or No)                                                    | For piping, determine if there is an injection or mix point in the circuit.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
| Type of Injection/Mix Point Inspection<br>(Highly Effective, or Not Highly Effective)             | For piping circuits which contain an injection or mix point, determine whether or not a highly effective inspection designed to detect local corrosion at these points has been performed.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
| Presence of a Deadleg<br>(Yes or No)                                                              | For piping, determine if there is a deadleg in the circuit.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
| Type of Inspection for Deadleg Corrosion<br>(Highly Effective or Not Highly Effective)            | For piping circuits which contain a deadleg, determine whether or not a highly effective inspection designed to detect local corrosion in deadlegs has been performed.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |

Table G-2—Steps to Determine Estimated Corrosion Rates (Corrosion Rate Not Established)

| Step | Action                                                                                         |
|------|------------------------------------------------------------------------------------------------|
| 1.   | Collect data for screening questions listed in Table G-4.                                      |
| 2.   | Answer screening questions in Table G-4.                                                       |
| 3.   | Collect data in Basic Data tables for each of the applicable Supplements identified in step 2. |

Table G-3—Limit State Function for Ductile Overload

| Expression                                                                     |                              | Description                   |                |
|--------------------------------------------------------------------------------|------------------------------|-------------------------------|----------------|
| $g_2 = s_f \left( 1 - \frac{\Delta t}{t} \right) - \frac{pD}{2t} 1$ (see note) |                              | $g_2 =$ Limit state function. |                |
| Variable                                                                       | Description                  | Variable                      | Description    |
| $s_f$                                                                          | Flow stress = $(s_y + UT)/2$ | $P$                           | Pressure       |
| $D$                                                                            | Diameter                     | $t$                           | Wall thickness |
| $\Delta t$                                                                     | Change in thickness          |                               |                |

Note: This limit state function applies to internal pressure only (not vacuum collapse).

Tables G-6A and B provide examples of inspection activities for general and localized thinning, respectively, that are both intrusive (requires entry into the equipment) and non-intrusive (can be performed externally). Note that the effectiveness category assigned to the inspection activity differs depending on whether the thinning is general or localized.

For localized thinning, selection of locations for examination must be based on a thorough understanding of the damage mechanism in the specific process. Guidance may be available in the following sections of this module.

### G.5.5 DETERMINATION OF NUMBER OF HIGHEST EFFECTIVENESS INSPECTIONS

The effectiveness of each inspection performed within the designated time period must be characterized in accordance with Tables G-6A and B, as appropriate. The number of highest effectiveness inspections will be used to determine the technical module subfactor. If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with the following relationships:

- “Usually Effective” inspections = 1 “Highly Effective” inspection.
- “Fairly Effective” inspections = 1 “Usually Effective” inspection.

### G.5.6 DETERMINATION OF TECHNICAL MODULE SUBFACTOR (TMSF)

The calculated  $ar/t$  and the number of highest effective inspections should be used to determine the technical module subfactor for thinning in Table G-7.

### G.5.7 ADJUSTMENT TO TMSF FOR OVERDESIGN

If equipment operates well below its maximum allowable working pressure (MAWP), this could significantly decrease the likelihood of failure. Therefore, a credit may be taken for significant overdesign.

Using the MAWP and operating pressure (OP), calculate the ratio MAWP/OP. Alternatively, the overdesign factor can be determined by calculating the ratio of the actual thickness ( $T_{act}$ ) divided by  $T_{act} -$  remaining corrosion allowance (CA) or  $T_{act}/(T_{act} - CA)$ . Use these ratios to determine the overdesign factor as indicated in Table G-8.

Multiply the TMSF by this overdesign factor to obtain an adjusted TMSF.

### G.5.8 ADJUSTMENT TO TMSF FOR ON-LINE MONITORING

In addition to inspection, on-line monitoring of corrosion (or key process variables affecting corrosion) is commonly used in many processes to prevent corrosion failures. The advantage of on-line monitoring is that changes in corrosion rates as a result of process changes can be detected long before periodic inspections. This earlier detection usually permits more timely action to be taken that should decrease the likelihood of failure. Various methods are employed, ranging from corrosion probes, corrosion coupons, and monitoring of key process variables. The BRD method acknowledges that if on-line monitoring is employed, credit should be given to reflect higher confidence in the predicted thinning rate. However, these methods have a varying degree of success depending on the specific thinning mechanism.

Using knowledge of the thinning mechanism and the type of on-line monitoring, determine the on-line monitoring

Table G-2—Steps to Determine Estimated Corrosion Rates (Corrosion Rate Not Established)

| Step | Action                                                                                         |
|------|------------------------------------------------------------------------------------------------|
| 1.   | Collect data for screening questions listed in Table G-4.                                      |
| 2.   | Answer screening questions in Table G-4.                                                       |
| 3.   | Collect data in Basic Data tables for each of the applicable Supplements identified in step 2. |

Table G-3—Limit State Function for Ductile Overload

| Expression                                                                     |                              | Description                   |                |
|--------------------------------------------------------------------------------|------------------------------|-------------------------------|----------------|
| $g_2 = s_f \left( 1 - \frac{\Delta t}{t} \right) - \frac{pD}{2t} 1$ (see note) |                              | $g_2 =$ Limit state function. |                |
| Variable                                                                       | Description                  | Variable                      | Description    |
| $s_f$                                                                          | Flow stress = $(s_y + UT)/2$ | $P$                           | Pressure       |
| $D$                                                                            | Diameter                     | $t$                           | Wall thickness |
| $\Delta t$                                                                     | Change in thickness          |                               |                |

Note: This limit state function applies to internal pressure only (not vacuum collapse).

Tables G-6A and B provide examples of inspection activities for general and localized thinning, respectively, that are both intrusive (requires entry into the equipment) and non-intrusive (can be performed externally). Note that the effectiveness category assigned to the inspection activity differs depending on whether the thinning is general or localized.

For localized thinning, selection of locations for examination must be based on a thorough understanding of the damage mechanism in the specific process. Guidance may be available in the following sections of this module.

### G.5.5 DETERMINATION OF NUMBER OF HIGHEST EFFECTIVENESS INSPECTIONS

The effectiveness of each inspection performed within the designated time period must be characterized in accordance with Tables G-6A and B, as appropriate. The number of highest effectiveness inspections will be used to determine the technical module subfactor. If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with the following relationships:

- “Usually Effective” inspections = 1 “Highly Effective” inspection.
- “Fairly Effective” inspections = 1 “Usually Effective” inspection.

### G.5.6 DETERMINATION OF TECHNICAL MODULE SUBFACTOR (TMSF)

The calculated  $ar/t$  and the number of highest effective inspections should be used to determine the technical module subfactor for thinning in Table G-7.

### G.5.7 ADJUSTMENT TO TMSF FOR OVERDESIGN

If equipment operates well below its maximum allowable working pressure (MAWP), this could significantly decrease the likelihood of failure. Therefore, a credit may be taken for significant overdesign.

Using the MAWP and operating pressure (OP), calculate the ratio MAWP/OP. Alternatively, the overdesign factor can be determined by calculating the ratio of the actual thickness ( $T_{act}$ ) divided by  $T_{act} -$  remaining corrosion allowance (CA) or  $T_{act}/(T_{act} - CA)$ . Use these ratios to determine the overdesign factor as indicated in Table G-8.

Multiply the TMSF by this overdesign factor to obtain an adjusted TMSF.

### G.5.8 ADJUSTMENT TO TMSF FOR ON-LINE MONITORING

In addition to inspection, on-line monitoring of corrosion (or key process variables affecting corrosion) is commonly used in many processes to prevent corrosion failures. The advantage of on-line monitoring is that changes in corrosion rates as a result of process changes can be detected long before periodic inspections. This earlier detection usually permits more timely action to be taken that should decrease the likelihood of failure. Various methods are employed, ranging from corrosion probes, corrosion coupons, and monitoring of key process variables. The BRD method acknowledges that if on-line monitoring is employed, credit should be given to reflect higher confidence in the predicted thinning rate. However, these methods have a varying degree of success depending on the specific thinning mechanism.

Using knowledge of the thinning mechanism and the type of on-line monitoring, determine the on-line monitoring

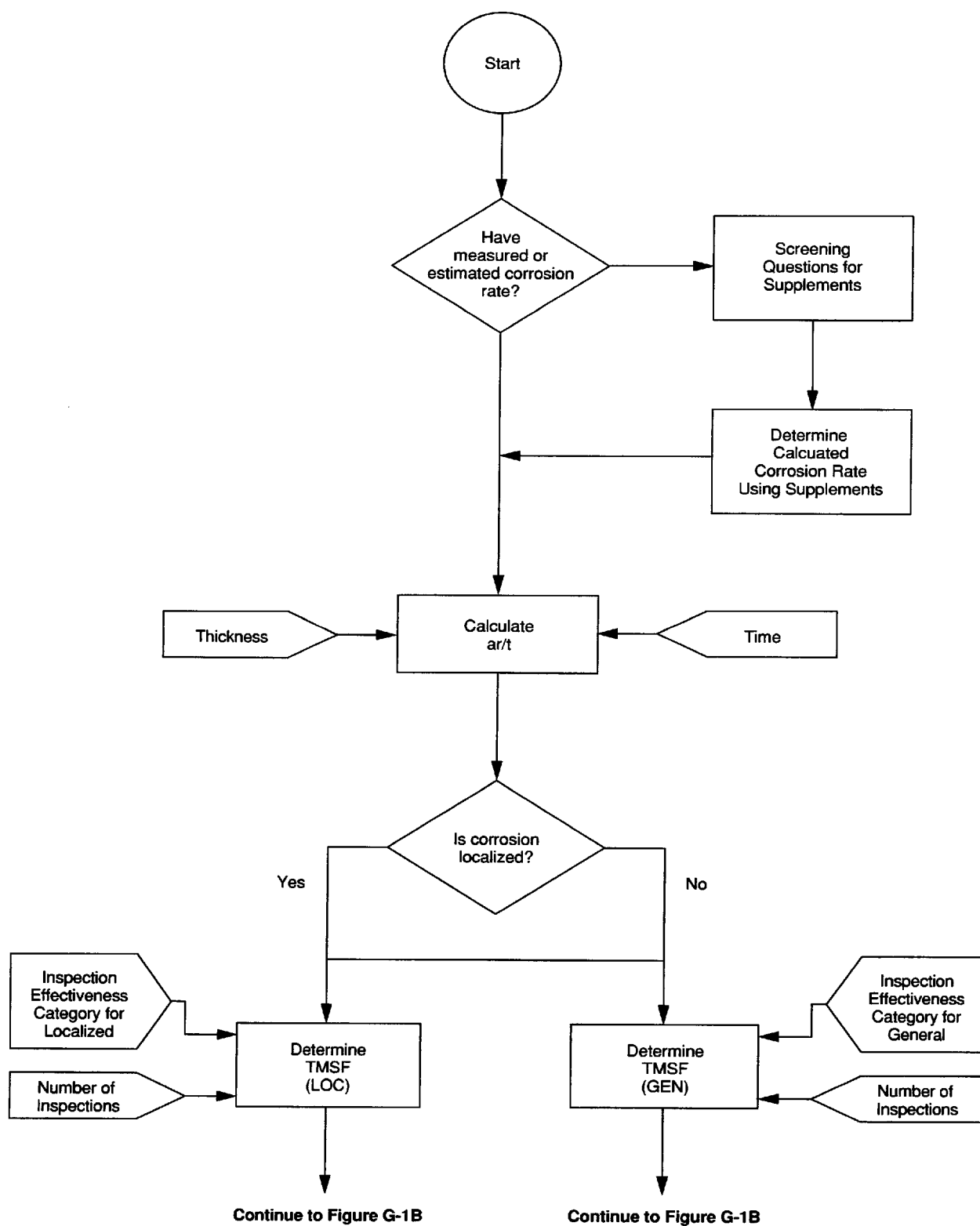
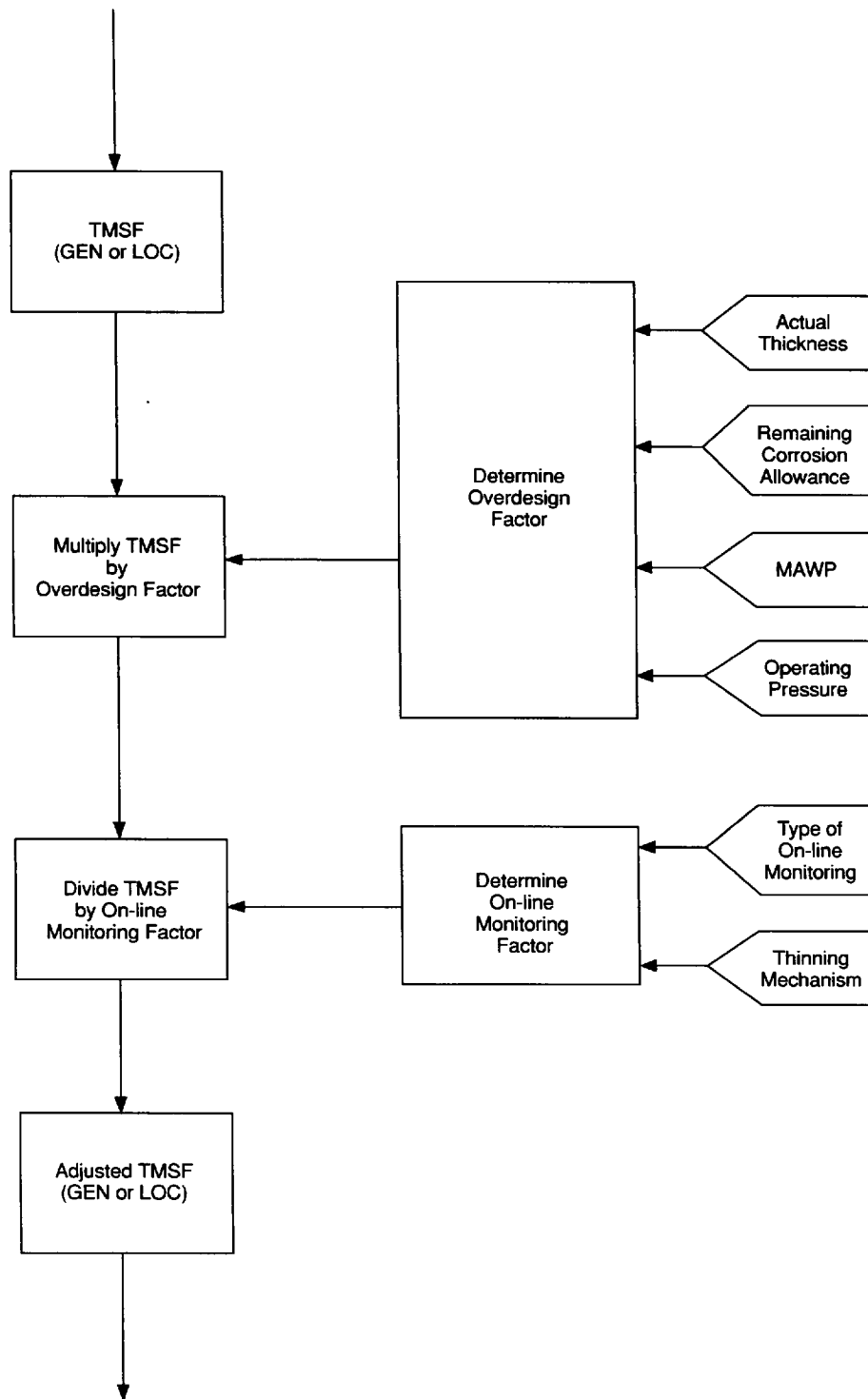


Figure G-1A—Determination of Technical Module Subfactors for Thinning

Continued from Figure G-1A



Continue to Figure G-1C

Figure G-1B—Determination of Technical Module Subfactors for Thinning



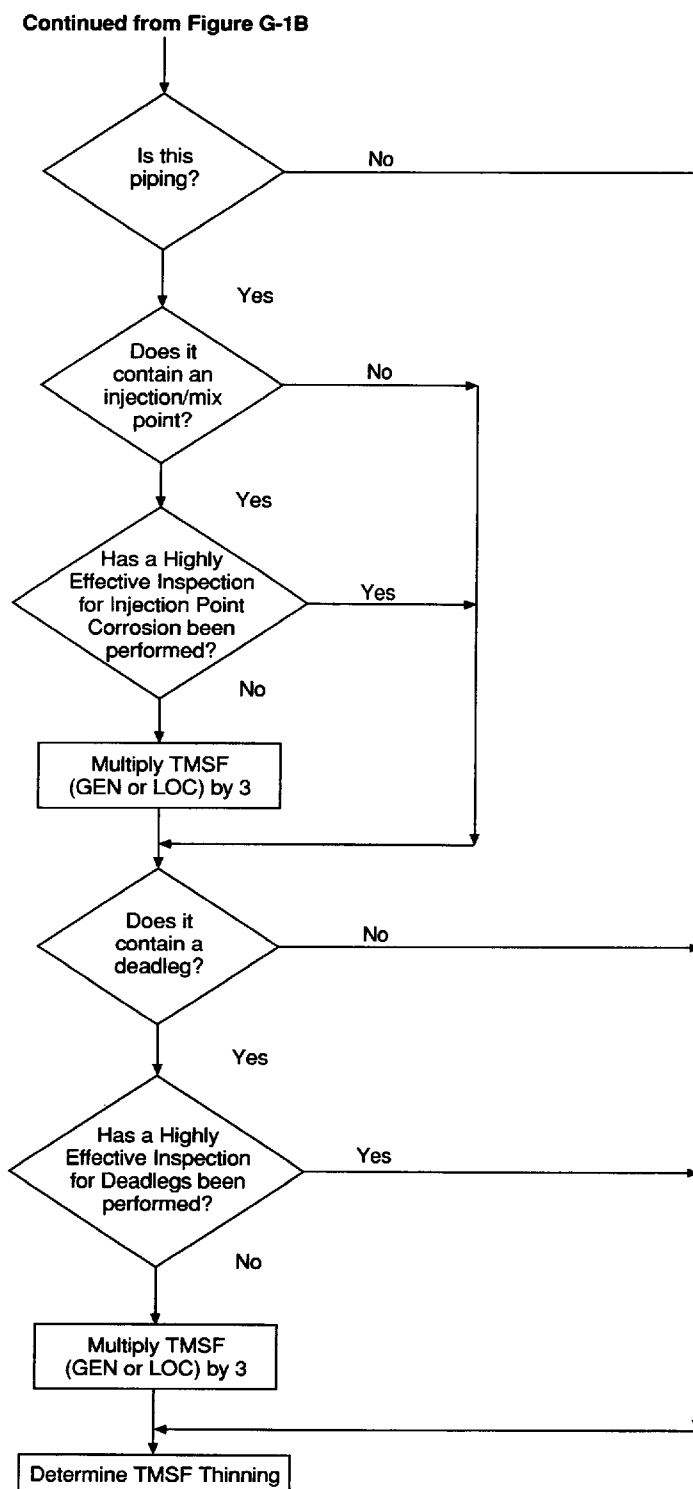


Figure G-1C—Determination of Technical Module Subfactors for Thinning

Table G-4—Screening Questions for Thinning Mechanisms

| Screening Questions                                                                                                                                                                | Action                           |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------|
| 1. Hydrochloric Acid (HCl) Corrosion<br>Does the process contain HCl?<br>Is free water present in the process stream (including initial condensing condition)?<br>Is the pH < 7.0? | If Yes to all, proceed to G.6.   |
| 2. High Temperature Sulfidic/Naphthenic Acid Corrosion<br>Does the process contain oil with sulfur compounds?<br>Is the operating temperature > 400°F?                             | If Yes to both, proceed to G.7.  |
| 3. High Temperature H <sub>2</sub> S/H <sub>2</sub> Corrosion<br>Does the process contain H <sub>2</sub> S and hydrogen?<br>Is the operating temperature > 400°F?                  | If Yes to both, proceed to G.8.  |
| 4. Sulfuric Acid (H <sub>2</sub> SO <sub>4</sub> ) Corrosion<br>Does the process contain H <sub>2</sub> SO <sub>4</sub> ?                                                          | If Yes, proceed to G.9.          |
| 5. Hydrofluoric Acid (HF) Corrosion<br>Does the process stream contain HF?                                                                                                         | If Yes, proceed to G.10.         |
| 6. Sour Water Corrosion<br>Is free water with H <sub>2</sub> S present?                                                                                                            | If Yes, proceed to G.11.         |
| 7. Amine Corrosion<br>Is equipment exposed to acid gas treating amines (MEA, DEA, DIPA, MDEA)?                                                                                     | If Yes, proceed to G.12.         |
| 8. High Temperature Oxidation<br>Is the temperature ≥ 900 °F?<br>Is there oxygen present?                                                                                          | If Yes to both, proceed to G.13. |

Table G-5—Type of Thinning

| Thinning Mechanism                                                                                        | Type of Thinning       |
|-----------------------------------------------------------------------------------------------------------|------------------------|
| Hydrochloric Acid (HCl) Corrosion                                                                         | Localized              |
| High Temperature Sulfidic/Naphthenic Acid Corrosion                                                       |                        |
| TAN ≤ 0.5                                                                                                 | General                |
| TAN > 0.5                                                                                                 | Localized              |
| High Temperature H <sub>2</sub> S/H <sub>2</sub> Corrosion                                                | General                |
| Sulfuric Acid (H <sub>2</sub> SO <sub>4</sub> ) Corrosion                                                 |                        |
| Low Velocity<br><= 2 ft/sec for carbon steel,<br><= 4 ft/sec for SS, and<br><= 6 ft/sec for higher alloys | General                |
| High Velocity<br>> 2 ft/sec for carbon steel,<br>> 4 ft/sec for SS, and<br>> 6 ft/sec for higher alloys   | Localized              |
| Hydrofluoric Acid (HF) Corrosion                                                                          | Localized              |
| Sour Water Corrosion                                                                                      |                        |
| Low Velocity<br><= 20 ft/sec                                                                              | General                |
| High Velocity<br>> 20 ft/sec                                                                              | Localized              |
| Amine Corrosion                                                                                           |                        |
| Low Velocity<br>< 5 fps rich amine<br>< 20 fps lean amine                                                 | General<br>General     |
| High Velocity<br>> 5 fps rich amine<br>> 20 fps lean amine                                                | Localized<br>Localized |
| High Temperature Oxidation                                                                                | General                |

Table G-6A—Guidelines for Assigning Inspection Effectiveness—General Thinning

| Inspection Effectiveness Category | Example:<br>Intrusive Inspection                                                                           | Example:<br>Nonintrusive Inspection                                                                                                             |
|-----------------------------------|------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | 50–100% examination of the surface (partial internals removed), and accompanied by thickness measurements. | 50–100% ultrasonic scanning coverage (automated or manual) or profile radiography                                                               |
| Usually Effective                 | Nominally 20% examination (no internals removed), and spot external ultrasonic thickness measurements.     | Nominally 20% ultrasonic scanning coverage (automated or manual), or profile radiography, or external spot thickness (statistically validated). |
| Fairly Effective                  | Visual examination without thickness measurements.                                                         | 2–3% examination, spot external ultrasonic thickness measurements, and little or no internal visual examination.                                |
| Poorly Effective                  | External spot thickness readings only.                                                                     | Several thickness measurements, and a documented inspection planning system.                                                                    |
| Ineffective                       | No inspection.                                                                                             | Several thickness measurements taken only externally, and a poorly documented inspection planning system.                                       |

Table G-6B—Guidelines for Assigning Inspection Effectiveness—Localized Thinning

| Inspection Effectiveness Category | Example:<br>Intrusive Inspection                                                                                             | Example:<br>Nonintrusive Inspection                                                                                                                                                                         |
|-----------------------------------|------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | 100% visual examination (with removal of internal packing, trays, etc.) and thickness measurements.                          | 50–100% coverage using automated ultrasonic scanning, or profile radiography in areas specified by a corrosion engineer or other knowledgeable specialist.                                                  |
| Usually Effective                 | 100% visual examination (with partial removal of the internals) including manways, nozzles, etc. and thickness measurements. | 20% coverage using automated ultrasonic scanning, or 50% manual ultrasonic scanning, or 50% profile radiography in areas specified by a corrosion engineer or other knowledgeable specialist.               |
| Fairly Effective                  | Nominally 20% visual examination and spot ultrasonic thickness measurements.                                                 | Nominally 20% coverage using automated or manual ultrasonic scanning, or profile radiography, and spot thickness measurements at areas specified by a corrosion engineer or other knowledgeable specialist. |
| Poorly Effective                  | No inspection.                                                                                                               | Spot ultrasonic thickness measurements or profile radiography without areas being specified by a corrosion engineer or other knowledgeable specialist.                                                      |
| Ineffective                       | No inspection.                                                                                                               | Spot ultrasonic thickness measurements without areas being specified by a corrosion engineer or other knowledgeable specialist.                                                                             |

factor from Table G-9. If more than one monitoring method is used, only the highest monitoring factor should be used (the factors are not additive). Divide the TMSF by this factor. Do not apply this factor if the TMSF is 1.

### G.5.9 ADJUSTMENT FOR INJECTION/MIX POINTS

An injection/mix point is defined as a point where a chemical (including water) is being added to the main flow stream. For this technical module, a corrosive mix point is defined as: a) mixing of vapor and liquid streams where vaporization of the liquid stream can occur; b) water is present in either or both streams; or c) temperature of the mixed streams is below the water dew point of the combined stream. If this is a piping circuit that contains an injection/mix point, then an adjust-

ment should be made to the TMSF to account for the higher likelihood of thinning activity at this location. The adjustment is made by multiplying the TMSF (the greater of general or localized TMSF) by a factor of 3. If a highly effective inspection specifically for injection/mix point corrosion within the injection point circuit (according to API 570) is performed, no adjustment is necessary.

### G.5.10 ADJUSTMENT FOR DEADLEGS

A deadleg is defined as a section of piping or piping circuit that is used only during intermittent service such as start-ups, shutdowns, or regeneration cycles rather than continuous service. If this is a piping circuit that contains a deadleg, then an adjustment should be made to the TMSF to account for the

Table G-7—Thinning Technical Module Subfactors

| Number of Inspections | 1                        |        |        |         | 2                        |        |        |         | 3                        |        |        |         | 4                        |        |        |         | 5                        |        |        |         | 6                        |        |        |         |        |
|-----------------------|--------------------------|--------|--------|---------|--------------------------|--------|--------|---------|--------------------------|--------|--------|---------|--------------------------|--------|--------|---------|--------------------------|--------|--------|---------|--------------------------|--------|--------|---------|--------|
|                       | Inspection Effectiveness |        |        |         | Inspection Effectiveness |        |        |         | Inspection Effectiveness |        |        |         | Inspection Effectiveness |        |        |         | Inspection Effectiveness |        |        |         | Inspection Effectiveness |        |        |         |        |
| ar/t                  | No Inspect.              | Poorly | Fairly | Usually | Highly                   | Poorly | Fairly | Usually | Highly                   | Poorly | Fairly | Usually | Highly                   | Poorly | Fairly | Usually | Highly                   | Poorly | Fairly | Usually | Highly                   | Poorly | Fairly | Usually | Highly |
| 0.02                  | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1      |
| 0.04                  | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1      |
| 0.06                  | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1      |
| 0.08                  | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1      |
| 0.10                  | 2                        | 2      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1                        | 1      | 1      | 1       | 1      |
| 0.12                  | 6                        | 5      | 3      | 2       | 1                        | 4      | 2      | 1       | 1                        | 3      | 1      | 1       | 1                        | 2      | 1      | 1       | 1                        | 2      | 1      | 1       | 1                        | 1      | 1      | 1       | 1      |
| 0.14                  | 20                       | 17     | 10     | 6       | 1                        | 13     | 6      | 1       | 1                        | 10     | 3      | 1       | 1                        | 7      | 2      | 1       | 1                        | 5      | 1      | 1       | 1                        | 4      | 1      | 1       | 1      |
| 0.16                  | 90                       | 70     | 50     | 20      | 3                        | 50     | 20     | 4       | 1                        | 40     | 10     | 1       | 1                        | 30     | 5      | 1       | 1                        | 20     | 2      | 1       | 1                        | 14     | 1      | 1       | 1      |
| 0.18                  | 250                      | 200    | 130    | 70      | 7                        | 170    | 70     | 10      | 1                        | 130    | 35     | 3       | 1                        | 100    | 15     | 1       | 1                        | 70     | 7      | 1       | 1                        | 50     | 3      | 1       | 1      |
| 0.20                  | 400                      | 300    | 210    | 110     | 15                       | 290    | 120    | 20      | 1                        | 260    | 60     | 5       | 1                        | 180    | 20     | 2       | 1                        | 120    | 10     | 1       | 1                        | 100    | 6      | 1       | 1      |
| 0.25                  | 520                      | 450    | 290    | 150     | 20                       | 350    | 170    | 30      | 2                        | 240    | 80     | 6       | 1                        | 200    | 30     | 2       | 1                        | 150    | 15     | 2       | 1                        | 120    | 7      | 1       | 1      |
| 0.30                  | 650                      | 550    | 400    | 200     | 30                       | 400    | 200    | 40      | 4                        | 320    | 110    | 9       | 2                        | 240    | 50     | 4       | 2                        | 180    | 25     | 3       | 2                        | 150    | 10     | 2       | 2      |
| 0.35                  | 750                      | 650    | 550    | 300     | 80                       | 600    | 300    | 80      | 10                       | 540    | 150    | 20      | 5                        | 440    | 90     | 10      | 4                        | 350    | 70     | 6       | 4                        | 280    | 40     | 5       | 4      |
| 0.40                  | 900                      | 800    | 700    | 400     | 130                      | 700    | 400    | 120     | 30                       | 600    | 200    | 50      | 10                       | 500    | 140    | 20      | 8                        | 400    | 110    | 10      | 8                        | 350    | 90     | 9       | 8      |
| 0.45                  | 1050                     | 900    | 810    | 500     | 200                      | 800    | 500    | 160     | 40                       | 700    | 270    | 60      | 20                       | 600    | 200    | 30      | 15                       | 500    | 160    | 20      | 15                       | 400    | 130    | 20      | 15     |
| 0.50                  | 1200                     | 1100   | 970    | 600     | 270                      | 1000   | 600    | 200     | 60                       | 900    | 360    | 80      | 40                       | 800    | 270    | 50      | 40                       | 700    | 210    | 40      | 40                       | 600    | 180    | 40      | 40     |
| 0.55                  | 1350                     | 1200   | 1130   | 700     | 350                      | 1100   | 750    | 300     | 100                      | 1000   | 500    | 130     | 90                       | 900    | 350    | 100     | 90                       | 800    | 260    | 90      | 90                       | 700    | 240    | 90      | 90     |
| 0.60                  | 1500                     | 1400   | 1250   | 850     | 500                      | 1300   | 900    | 400     | 230                      | 1200   | 620    | 250     | 210                      | 1000   | 450    | 220     | 210                      | 900    | 360    | 210     | 210                      | 800    | 300    | 210     | 210    |
| 0.65                  | 1900                     | 1700   | 1400   | 1000    | 700                      | 1600   | 1105   | 670     | 530                      | 1300   | 880    | 550     | 500                      | 1200   | 700    | 530     | 500                      | 1100   | 640    | 500     | 500                      | 1000   | 600    | 500     | 500    |

**Instructions:**

1. Find the row with the calculated ar/t value or the next higher value, or interpolation may be used between rows.
2. Determine subfactor under appropriate column for number of inspections of the highest inspection effectiveness.

Table G-8—Guidelines for Determining the Overdesign Factor

| MAWP/OP<br>$T_{act} / (T_{act} - CA)$ | Overdesign Factor |
|---------------------------------------|-------------------|
| 1.0 to 1.5                            | 1.0               |
| > 1.5                                 | 0.5               |

higher likelihood of thinning activity at this location. The adjustment is made by multiplying the TMSF (the greater of general or localized TMSF) by a factor of 3. If a highly effective inspection method is used to address the potential of localized corrosion in the deadleg, no adjustment is necessary.

## G.6 Hydrochloric Acid (HCl) Corrosion

### G.6.1 DESCRIPTION OF DAMAGE

Hydrochloric acid (HCl) corrosion is a concern in some of the most common refining process units. HCl is aggressive to many common materials of construction across a wide range

of concentrations and is often localized in nature, particularly when it is associated with localized or "shock" condensation or the deposition of chloride containing ammonia or amine salts. Austenitic stainless steels will often suffer pitting attack and may experience crevice corrosion and/or chloride stress corrosion cracking. Some of the nickel-based alloys may experience accelerated corrosion if oxidizing agents are present or if the alloys are not in the solution annealed heat treatment condition.

The primary refining units where HCl corrosion is a concern are crude distillation, hydrotreating, and catalytic reforming. HCl forms in crude units by the hydrolysis of magnesium and calcium chloride salts and results in dilute HCl in the overhead system. In hydrotreating units, HCl may form by hydrogenation of organic chlorides in the feed or can enter the unit with hydrocarbon feed or hydrogen and condense with water in the effluent train. In catalytic reforming units, chlorides may be stripped off of the catalyst and hydrogenate resulting in HCl corrosion in the effluent train or regeneration systems.

Table G-9—On-Line Monitoring Adjustment Factor Table

| Thinning Mechanism                                                                                                     | Key Process Variables                    | Corrosometer Probes | Corrosion Coupons |
|------------------------------------------------------------------------------------------------------------------------|------------------------------------------|---------------------|-------------------|
| Hydrochloric Acid (HCl) Corrosion                                                                                      | 10<br>(20 if in conjunction with Probes) | 10                  | 2                 |
| High Temperature Sulfidic/Naphthenic Acid Corrosion                                                                    | 10                                       | 10                  | 2                 |
| High Temperature H <sub>2</sub> S/H <sub>2</sub> Corrosion                                                             | 1                                        | 10                  | 1                 |
| Sulfuric Acid (H <sub>2</sub> S/H <sub>2</sub> ) Corrosion                                                             |                                          |                     |                   |
| Low Velocity<br>≤ 3 fps for CS,<br>≤ 5 fps for SS,<br>≤ 7 fps for higher alloys                                        | 20                                       | 10                  | 2                 |
| High Velocity<br>(20 if in conjunction with Probes)<br>> 3 fps for CS,<br>> 5 fps for SS,<br>> 7 fps for higher alloys | 10                                       | 10                  | 1                 |
| Hydrofluoric Acid (HF) Corrosion                                                                                       | 10                                       | 1                   | 1                 |
| Sour Water Corrosion                                                                                                   | 20                                       | 10                  | 2                 |
| Low Velocity<br>≤ 20 fps                                                                                               | 20                                       | 10                  | 2                 |
| High Velocity<br>> 20 fps                                                                                              | 10                                       | 2                   | 2                 |
| Amine                                                                                                                  |                                          |                     |                   |
| Low Velocity                                                                                                           | 20                                       | 10                  | 2                 |
| High Velocity                                                                                                          | 10                                       | 10                  | 1                 |
| Oxidation                                                                                                              | 20                                       | 1                   | 1                 |

Factors are not additive unless noted. This table assumes that an organized on-line monitoring plan is in place that recognizes the potential corrosion mechanism. Key process variables are, for example, oxygen, pH, water content, velocity, Fe content, temperature, pressure, H<sub>2</sub>S content, CN levels, etc. The applicable variable(s) should be monitored at an appropriate interval, as determined by a knowledgeable specialist. For example: Coupons may be monitored quarterly while pH, chlorides, etc. may be monitored weekly.

## G.6.2 BASIC DATA

The data listed in Table G-10 are required to estimate the rate of corrosion in dilute hydrochloric acid. More concentrated acid is outside the scope of this section. Figure G-2 illustrates the steps required to determine the corrosion rate. If precise data have not been measured, a knowledgeable process specialist should be consulted.

## G.6.3 DETERMINATION OF HYDROCHLORIC ACID CORROSION RATE

Tables G-12, G-13, G-14, and G-15 should be used to estimate the corrosion rates of various materials exposed to dilute hydrochloric acid.

### References

1. *Metals Handbook*, Vol. 13, "Corrosion," ASM International.
2. T. S. Lee, III, and F.G. Hodge, *Resistance of Hastelloy Alloys to Corrosion by Inorganic Acids*, *Materials Performance*, September 1976, pp. 29.
3. *Corrosion Resistance of Hastelloy Alloys*, Haynes International, Inc., 1984.

4. *Resistance to Corrosion*, Inco Alloys International, Inc.
5. "Resistance of Nickel and High Nickel Alloys to Corrosion by Hydrochloric Acid, Hydrogen Chloride and Chlorine," *Corrosion Engineering Bulletin CEB-3*, The International Nickel Company, Inc., 1969.
6. L. Colombier and J. Hochmann, *Stainless and Heat Resisting Steels*, St. Martins Press, New York, NY.

## G.7 High Temperature Sulfidic and Naphthenic Acid Corrosion

### G.7.1 DESCRIPTION OF DAMAGE

High temperature sulfidic corrosion is a form of normally uniform corrosion which can occur at temperatures typically above about 400°F. This form of corrosion sometimes occurs along with naphthenic acid corrosion depending on the oil being processed. Naphthenic acid corrosion, when it occurs, is normally localized.

Sulfur species occur naturally in most crude oils but their concentrations vary from crude-to-crude. These naturally occurring compounds may be corrosive themselves as well as when they are converted to hydrogen sulfide through thermal

Table G-10—Basic Data Required for Analysis of HCl Corrosion

| Basic Data                              | Comments                                                                                                                                                                                                                                                                                            |
|-----------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Material of Construction                | Determine the material of construction of the equipment/piping.                                                                                                                                                                                                                                     |
| pH                                      | pH is preferred for estimating the corrosion rate at dilute concentrations for carbon steel and 300 series stainless steels. Table G-11 can be used to estimate pH from the Cl <sup>-</sup> concentration if it is known. Note that the presence of neutralizing agents may elevate the pH however. |
| OR                                      | Note: The pH used should be of the separated acid phase within this equipment or nearest equipment downstream, e.g. the overhead accumulator boot water downstream of the overhead condenser.                                                                                                       |
| Maximum Temperature (°F)                | For high alloy materials, Cl <sup>-</sup> concentration is used to estimate the corrosion rate.                                                                                                                                                                                                     |
| Presence of Air or Oxidants (Yes or No) | Determine the maximum temperature present in this equipment/piping. This may be the maximum process temperature, but local heating condition such as effect of the sun or heat tracing should be considered.                                                                                        |
|                                         | Presence of air (oxygen) may increase corrosion rates, particularly for Alloy 400 and Alloy B-2. Other oxidants such as ferric and cupric ions will have a similar effect on these alloys.                                                                                                          |

Table G-11—Determination of pH from Cl<sup>-</sup> Concentration<sup>a</sup>

| Cl <sup>-</sup> Concentration (wppm) | pH  |
|--------------------------------------|-----|
| 3,601 – 12,000                       | 0.5 |
| 1,201 – 3600                         | 1.0 |
| 361 – 1,200                          | 1.5 |
| 121 – 360                            | 2.0 |
| 36 – 120                             | 2.5 |
| 16 – 35                              | 3.0 |
| 6 – 15                               | 3.5 |
| 3 – 5                                | 4.0 |
| 1 – 2                                | 4.5 |
| < 1                                  | 5.0 |

<sup>a</sup>Assumes no alkaline agent present (NH<sub>3</sub>, neutralizing amines or caustic)

Table G-12—Estimated Corrosion Rates for Carbon Steel (mpy)

| pH        | Temperature (°F) |           |           |       |
|-----------|------------------|-----------|-----------|-------|
|           | 100              | 100 – 150 | 151 – 200 | > 200 |
| ≤ 0.5     | 999              | 999       | 999       | 999   |
| 0.6 – 1.0 | 900              | 999       | 999       | 999   |
| 1.1 – 1.5 | 400              | 999       | 999       | 999   |
| 1.6 – 2.0 | 200              | 700       | 999       | 999   |
| 2.1 – 2.5 | 100              | 300       | 400       | 560   |
| 2.6 – 3.0 | 60               | 130       | 200       | 280   |
| 3.1 – 3.5 | 40               | 70        | 100       | 140   |
| 3.6 – 4.0 | 30               | 50        | 90        | 125   |
| 4.1 – 4.5 | 20               | 40        | 70        | 100   |
| 4.6 – 5.0 | 10               | 30        | 50        | 70    |
| 5.1 – 5.5 | 7                | 20        | 30        | 40    |
| 5.6 – 6.0 | 4                | 1         | 20        | 30    |
| 6.1 – 6.5 | 3                | 10        | 15        | 20    |
| 6.6 – 7.0 | 2                | 5         | 7         | 10    |

Note: These rates are 10 times the general corrosion rates to account for localized pitting corrosion.

Table G-13—Estimated Corrosion Rates for 300 Series Stainless Steels (mpy)

| pH        | Temperature (°F) |           |           |       |
|-----------|------------------|-----------|-----------|-------|
|           | 100              | 100 – 150 | 151 – 200 | > 200 |
| ≤ 0.5     | 900              | 999       | 999       | 999   |
| 0.6 – 1.0 | 500              | 999       | 999       | 999   |
| 1.1 – 1.5 | 300              | 500       | 700       | 999   |
| 1.6 – 2.0 | 150              | 260       | 400       | 500   |
| 2.1 – 2.5 | 80               | 140       | 200       | 250   |
| 2.6 – 3.0 | 50               | 70        | 100       | 120   |
| 3.1 – 3.5 | 30               | 40        | 50        | 65    |
| 3.6–4.0   | 20               | 25        | 30        | 35    |
| 4.1 – 4.5 | 10               | 15        | 20        | 25    |
| 4.6 – 5.0 | 5                | 7         | 10        | 12    |
| 5.1 – 5.5 | 4                | 5         | 6         | 7     |
| 5.6 – 6.0 | 3                | 4         | 5         | 6     |
| 6.1 – 6.5 | 2                | 3         | 4         | 5     |
| 6.6 – 7.0 | 1                | 2         | 2         | 4     |

Note: These rates are 10 times the general corrosion rates to account for localized pitting corrosion.

Table G-14—Estimated Corrosion Rates for Alloys 825, 20, 625, C-276

| Alloy                  | Cl- Concentration (wt%) | Temperature (°F) |           |           |       |
|------------------------|-------------------------|------------------|-----------|-----------|-------|
|                        |                         | < 100            | 100 – 150 | 151 – 200 | > 200 |
| Alloy 825 and Alloy 20 | ≤ 0.5                   | 1                | 3         | 40        | 200   |
|                        | 0.5 – 1                 | 2                | 5         | 80        | 400   |
|                        | > 1 – 5                 | 10               | 70        | 300       | 999   |
| Alloy 625              | ≤ 0.5                   | 1                | 2         | 15        | 75    |
|                        | 0.5 – 1                 | 1                | 5         | 25        | 125   |
|                        | > 1 – 5                 | 2                | 70        | 200       | 400   |
| Alloy C-276            | ≤ 0.5                   | 1                | 2         | 8         | 30    |
|                        | 0.5 – 1                 | 1                | 2         | 15        | 75    |
|                        | > 1 – 5                 | 2                | 10        | 60        | 300   |

Table G-15—Estimated Corrosion Rates for Alloy B-2 and Alloy 400

| Alloy     | Cl- Concentration<br>(wt%) | Temperature (°F)         |    |           |     |           |     |       |     |
|-----------|----------------------------|--------------------------|----|-----------|-----|-----------|-----|-------|-----|
|           |                            | 100                      |    | 100 – 150 |     | 151 – 200 |     | > 200 |     |
|           |                            | Oxygen/Oxidants Present? |    |           |     |           |     |       |     |
|           |                            | N                        | Y  | N         | Y   | N         | Y   | N     | Y   |
| Alloy B-2 | ≤ 0.5                      | 1                        | 4  | 1         | 4   | 2         | 8   | 4     | 16  |
|           | 0.5 – 1                    | 1                        | 4  | 1         | 4   | 5         | 20  | 20    | 80  |
|           | > 1 – 5                    | 2                        | 8  | 5         | 20  | 10        | 40  | 25    | 100 |
| Alloy 400 | ≤ 0.5                      | 1                        | 4  | 3         | 12  | 30        | 120 | 300   | 999 |
|           | 0.5 – 1                    | 2                        | 10 | 5         | 20  | 80        | 320 | 800   | 999 |
|           | > 1 – 5                    | 19                       | 40 | 25        | 100 | 150       | 600 | 900   | 999 |

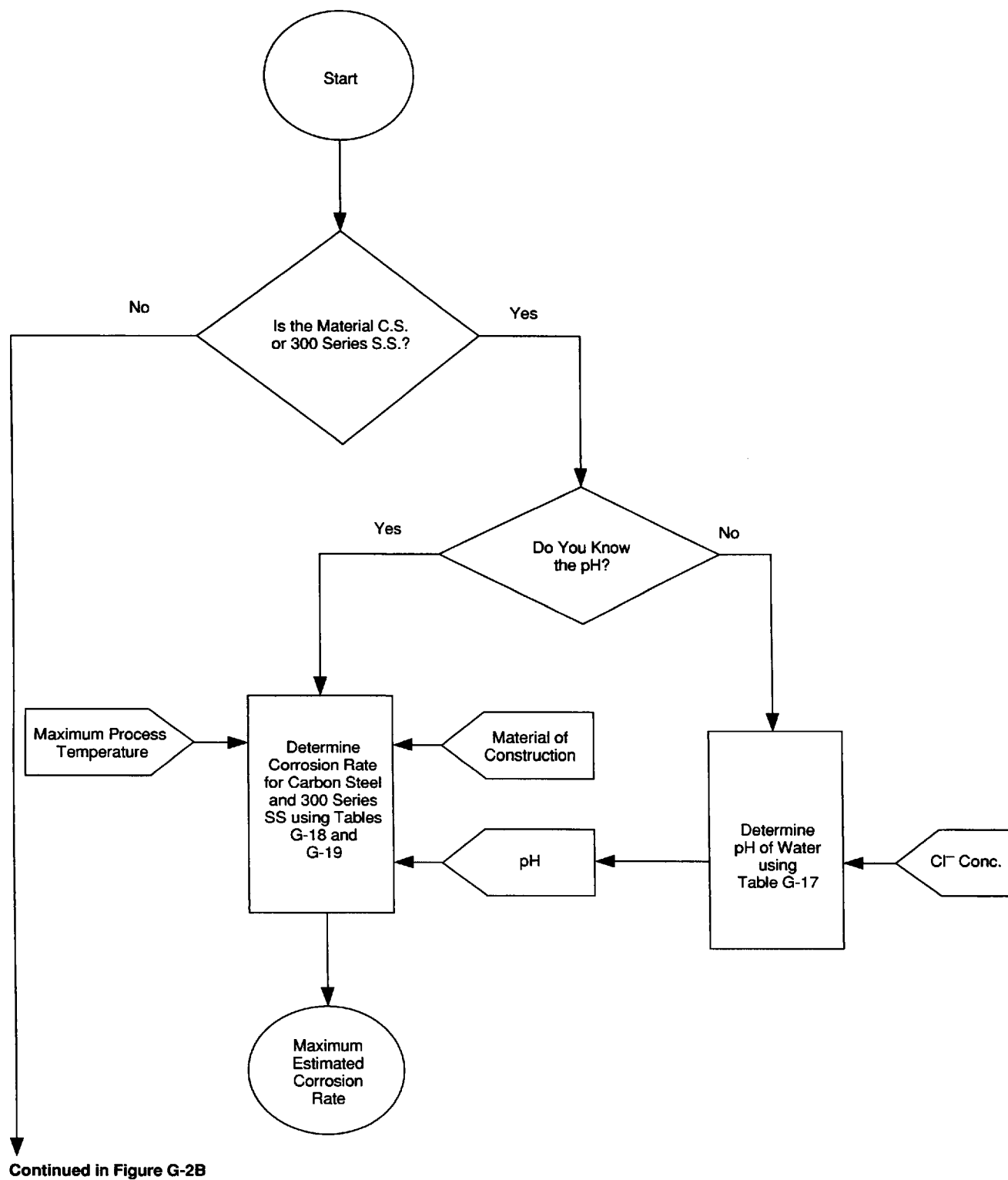


Figure G-2A—Determination of HCl Corrosion Rates



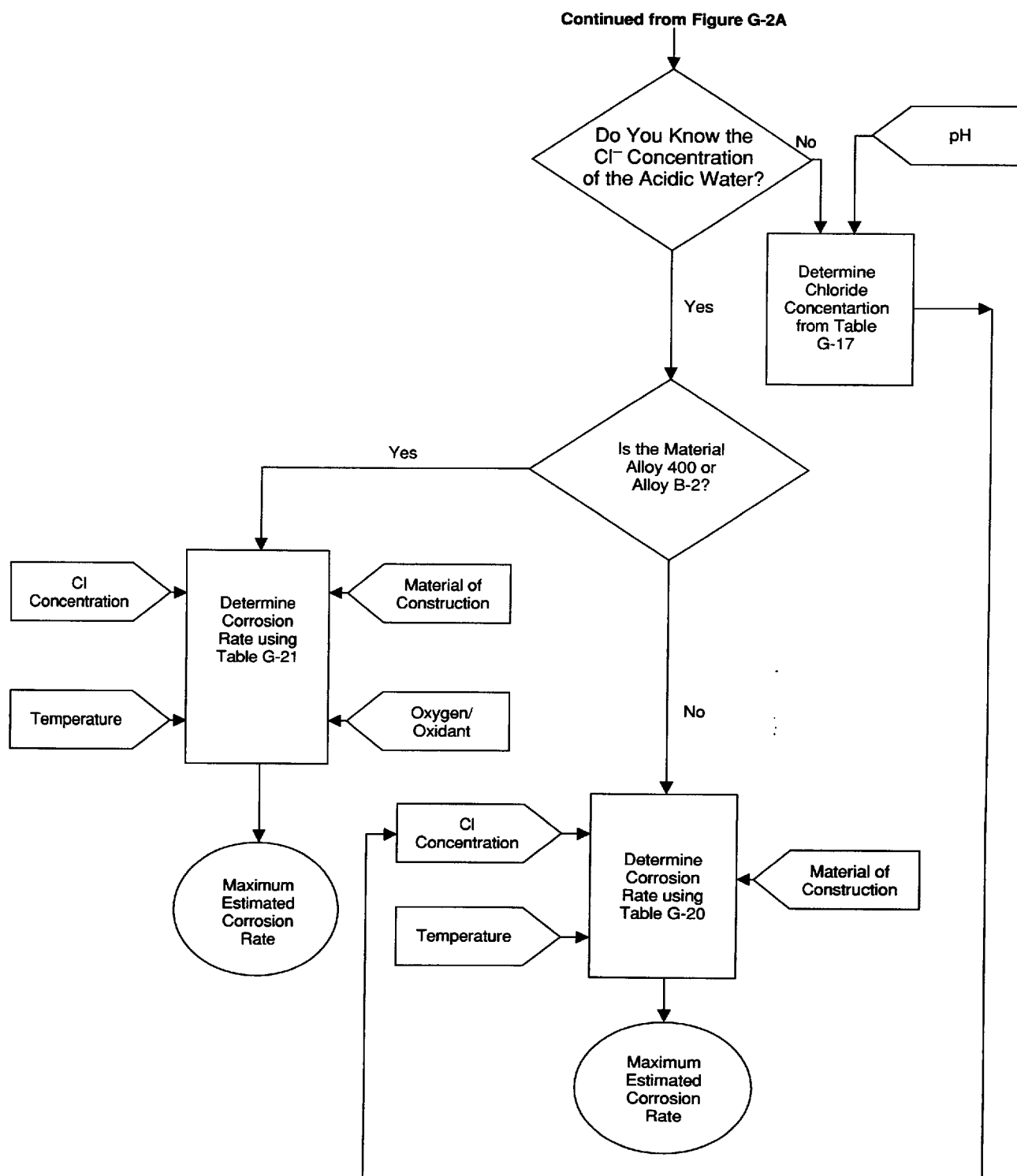


Figure G-2B—Determination of HCl Corrosion Rates

decomposition. Catalytic conversion of sulfur compounds to  $H_2S$  occurs in the presence of hydrogen and a catalyst bed in hydroprocessing units. Corrosion in vapor streams containing both  $H_2S$  and hydrogen is covered in G.8.

As with sulfur compounds, naphthenic acids occur naturally in some crude oils. During distillation, these acids tend to concentrate in higher boiling point fractions such as heavy atmospheric gas oil, atmospheric resid, and vacuum gas oils. The acids may also be present in vacuum resid, but often many of the more corrosive ones will have distilled into the vacuum sidestreams. Lower boiling point streams are usually low in naphthenic acids. Corrosion may appear either as pitting, more common at lower acid levels, or grooving and gouging at higher acid levels and, particularly, at higher velocities. Naphthenic acids may modify or destabilize protective films (sulfides or oxides) on the material and thus allow a high sulfidation corrosion rate to continue or it may itself directly attack the base material.

The corrosion rate in high temperature sulfidic environments is a function of the material, temperature, and the concentration of the sulfur compound(s) present. The presence of naphthenic acid in sufficient amounts, however, can dramatically decrease a material's corrosion resistance where it might otherwise have suitable corrosion resistance. The following summarize the key variables in corrosion:

- a. In high temperature sulfidic environments, materials such as carbon and low alloy steels form sulfide corrosion products. The extent to which these are protective depends on the environmental factors mentioned. At high enough temperatures and/or sulfur levels, the corrosion products may become less protective so corrosion can occur at an accelerated rate.
- b. Moderate additions of chromium to carbon steel increase the material's corrosion resistance. Alloys containing 5%, 7% and 9% Cr are often sufficient to provide acceptable material performance in these environments. Lower alloys such as  $1\frac{1}{4}$  and  $2\frac{1}{4}$  Cr generally do not offer sufficient benefits over carbon steel to justify their use. Stainless steels such as 12% Cr (410, 410S, 405SS) and Type 304 SS may be required at particularly high sulfur levels and temperatures.
- c. Sulfidation corrosion is related to the amount of sulfur present in the stream and is usually reported simply as wt.% sulfur. Corrosion generally increases with increasing sulfur content.
- d. High temperature sulfidic corrosion occurs at temperatures greater than about 400°F. Naphthenic acid corrosion typically has been observed in the 400–750°F temperature range although corrosion which exhibits naphthenic acid characteristics has been reported outside this temperature range. Above 750°F, the naphthenic acids either break down or distill into the vapor phase. While sulfidation will occur in both liquid and vapor phases, naphthenic acid corrosion occurs only where liquid phase is present.

e. The materials most vulnerable to naphthenic acid corrosion are carbon steel and the iron-chrome (5–12% Cr) alloys commonly used in corrosive refining services. 12% Cr may experience corrosion rates greater than that of carbon steel. Type 304 stainless steel offers some resistance to naphthenic acid corrosion at lower acid levels but normally the molybdenum containing austenitic stainless steels (Type 316 or Type 317 SS) are required for resistance to greater acid concentrations. It has been found that a minimum Mo content of 2.5% is required in Type 316 SS to provide the best resistance to naphthenic acids.

f. The amount of naphthenic acid present is most commonly indicated by a "neutralization number" or "total acid number" (TAN). The various acids which comprise the naphthenic acid family can have distinctly different corrosivities. The TAN is determined by an ASTM standard titration and is reported in mg KOH/g which is the amount of potassium hydroxide (KOH) required to neutralize the acidity of one gram of oil sample. While both colorimetric and potentiometric titration methods are available, the potentiometric method covered by ASTM D664 is the more commonly used one. It should be noted that the titration neutralizes all of the acids present and not just the naphthenic acids. For example, dissolved hydrogen sulfide will be represented in the TAN of a sample. From a corrosion standpoint, the TAN of the liquid hydrocarbon stream being evaluated rather than the TAN of the whole crude is the important parameter in determining susceptibility to naphthenic acid corrosion.

g. Another important factor in corrosion is the stream velocity, particularly where naphthenic acid is a factor in corrosion. Increased velocity increases the corrosivity by enhancing removal of protective sulfides. This effect is most pronounced in mixed liquid-vapor phase systems where velocities may be high.

h. At particularly low sulfur levels, naphthenic acid corrosion may be more severe, even at low TAN since protective sulfides may not readily form.

The process units where sulfidic and naphthenic acid corrosion is most commonly observed are atmospheric and vacuum crude distillation as well as the feed systems of downstream units such as hydrotreaters, catalytic crackers, and cokers. In hydrotreaters, naphthenic acid corrosion has not been reported downstream of the hydrogen addition point, even upstream of the reactor. Catalytic crackers and cokers thermally decompose naphthenic acids so this form of corrosion is also not normally reported in the fractionation sections of these units unless uncracked feed is carried in. Naphthenic acids can appear in high concentrations in lube extract oil streams when naphthenic acid containing feeds are processed. It should be noted that, where naphthenic acids may thermally decompose, lighter organic acids or carbon dioxide may form which can affect the corrosivity of condensed waters.

## G.7.2 BASIC DATA

The data listed in Table G-16 are required to determine the estimated rate of corrosion in high temperature sulfidic and naphthenic acid service. Figure G-16 illustrates the steps required to determine the corrosion rate. If precise data have not been measured, a knowledgeable process specialist should be consulted.

## G.7.3 DETERMINATION OF HIGH TEMPERATURE SULFIDIC AND NAPHTHENIC ACID CORROSION RATE

An estimation of corrosion rate may be determined from Tables G-17, G-18, G-19, G-20, G-21, G-22, G-23, G-24, and G-25. The corrosion rate in high temperature sulfidic environments in the absence of a naphthenic acid influence is based upon the modified McConomy curves. While various papers have been presented on naphthenic acid corrosion, no widely accepted correlations have yet been developed between corrosion rate and the various factors influencing it. Consequently, the corrosion rate to be used when naphthenic acid is a factor establish only an order-of-magnitude corrosion rate. Once a corrosion rate is selected from the appropriate table, it should be multiplied by a factor of 5 if the velocity is > 100 fps.

### References

1. F. McConomy, *High-Temperature Sulfidic Corrosion in Hydrogen-Free Environment*, API Division of Refining, Vol. 43 (III), 1963.
2. J. Gutzeit, *High Temperature Sulfidic Corrosion of Steels*, *Process Industries Corrosion*, NACE, Appendix 3, pg. 367.
3. *High Temperature Crude Oil Corrosivity Studies*, American Petroleum Institute, Publication 943, September 1974.
4. A. Derungs, "Naphthenic Acid Corrosion—An Old Enemy of the Petroleum Industry," *Corrosion*, Vol. 12 No. 12, pp. 41.
5. J. Gutzeit, "Naphthenic Acid Corrosion," NACE Paper No. 156, Corrosion/76.
6. Blanco and B. Hopkinson, "Experience with Naphthenic Acid Corrosion in Refinery Distillation Process Units," NACE Paper No. 99, Corrosion/93.
7. R. Piehl, "Naphthenic Acid Corrosion in Crude Distillation Units," *Materials Performance*, January, 1988.
8. H. L. Craig, Jr., "Naphthenic Acid Corrosion in the Refinery," NACE Paper No. 333, Corrosion/95.
9. S. Tebbal and R. D. Kane, "Review of Critical Factors Affecting Crude Corrosivity," NACE Paper No. 607, Corrosion/96.
10. H. L. Craig, Jr., "Temperature and Velocity Effects in Naphthenic Acid Corrosion," NACE Paper No. 608, Corrosion/96.

## G.8 High Temperature H<sub>2</sub>S/H<sub>2</sub> Corrosion

### G.8.1 DESCRIPTION OF DAMAGE

High temperature H<sub>2</sub>S/H<sub>2</sub> corrosion is a form of normally uniform corrosion which can occur at temperatures typically above about 400 °F. This form of sulfidation corrosion differs from high temperature sulfidic and naphthenic corrosion described in Supplement C. H<sub>2</sub>S/H<sub>2</sub> corrosion occurs in hydroprocessing units, e.g., hydrodesulfurizers and hydrocrackers, once sulfur compounds are converted to hydrogen sulfide via catalytic reaction with hydrogen. Conversion of sulfur compounds to H<sub>2</sub>S typically does not occur to a significant extent in the presence of hydrogen, even at elevated temperatures, unless a catalyst is present. The corrosion rate is a function of the material of construction, temperature, nature of the process stream and the concentration of H<sub>2</sub>S.

In H<sub>2</sub>S/H<sub>2</sub> environments, low levels of chromium (e.g., 5 to 9% Cr) provide only a modest increase the corrosion resistance of steel. A minimum of 12% Cr is needed to provide a significant decrease in corrosion rate. Further addition of chromium and nickel provides a substantial increase in corrosion resistance.

The nature of the process stream is a factor in determining the corrosion rate. In H<sub>2</sub>S/H<sub>2</sub> environments alone (all vapor), corrosion rates may be as much as 50% greater than in the presence of hydrocarbons as suggested by the referenced NACE committee report. Nevertheless, the correlations developed by Couper and Gorman are used for estimating corrosion rates in both hydrocarbon free and hydrocarbon containing services. The predicted rates in both services are very high at high H<sub>2</sub>S levels and temperatures and the one set of data are satisfactory for risk based inspection assessment purposes of either situation.

### G.8.2 BASIC DATA

The data listed in Table G-26 are required to determine the rate of corrosion in high temperature H<sub>2</sub>S/H<sub>2</sub> service. Figure G-4 illustrates the steps required to determine the corrosion rate. If precise data have not been measured, a knowledgeable process specialist should be consulted.

### G.8.3 DETERMINATION OF HIGH TEMPERATURE H<sub>2</sub>S/ H<sub>2</sub> CORROSION RATE

The estimated corrosion rate in H<sub>2</sub>S/H<sub>2</sub> environments is determined using Tables G-27, G-28, G-29, G-30, G-31, and G-32 which contain data from the correlations developed by Cooper and Gorman.

### References

1. "High Temperature Hydrogen Sulfide Corrosion of Stainless Steel," NACE Technical Committee Report, *Corrosion*, January 1958.
2. "Iso-Corrosion Rate Curves for High Temperature Hydrogen-Hydrogen Sulfide," NACE Technical Committee Report, *Corrosion*, Vol. 15, March 1959.

Table G-16—Basic Data Required for Analysis of High Temperature and Naphthenic Corrosion

| Basic Data                                             | Comments                                                                                                                                                                               |
|--------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Material of Construction                               | Determine the material of construction of the equipment/piping.<br><br>For 316 SS, if the Mo content is not known, assume it is < 2.5 wt. %.                                           |
| Maximum Temperature, (°F)                              | Determine maximum temperature of the process stream.                                                                                                                                   |
| Sulfur Content of the Stream                           | Determine the Sulfur content of the stream that is in this piece of equipment. If Sulfur content is not known, contact knowledgeable process engineer for an estimate.                 |
| Total Acid Number (TAN)<br>(TAN = mg KOH/g oil sample) | The TAN of importance is that of the liquid hydrocarbon phase present in the equipment/piping being evaluated. If not known, consult a knowledgeable process engineer for an estimate. |
| Velocity                                               | Determine the maximum velocity in this equipment/piping. Although conditions in a vessel may be essentially stagnant, the velocity in flowing nozzles should be considered.            |

Table G-17—Estimated Corrosion Rates for Carbon Steel (mpy)

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |           |           |           |           |           |           |      |
|------------------|---------------|------------------|-----------|-----------|-----------|-----------|-----------|-----------|------|
|                  |               | <450             | 451 - 500 | 501 - 550 | 551 - 600 | 601 - 650 | 651 - 700 | 701 - 750 | >750 |
| ≤ 0.2            | ≤ 0.3         | 1                | 3         | 7         | 15        | 20        | 35        | 50        | 60   |
|                  | 0.31 - 1.0    | 5                | 15        | 25        | 35        | 45        | 55        | 65        | 75   |
|                  | 1.1 - 2.0     | 20               | 25        | 35        | 65        | 120       | 150       | 180       | 200  |
|                  | 2.1 - 4.0     | 30               | 60        | 60        | 120       | 150       | 160       | 240       | 240  |
|                  | > 4.0         | 40               | 80        | 100       | 160       | 180       | 200       | 280       | 300  |
| 0.21-0.6         | ≤ 0.5         | 1                | 4         | 10        | 20        | 30        | 50        | 70        | 80   |
|                  | 0.51 - 1.0    | 5                | 10        | 15        | 25        | 40        | 60        | 80        | 90   |
|                  | 1.1 - 2.0     | 8                | 15        | 25        | 35        | 50        | 75        | 90        | 110  |
|                  | 2.1 - 4.0     | 10               | 20        | 35        | 50        | 70        | 100       | 120       | 130  |
|                  | > 4.0         | 20               | 30        | 50        | 70        | 90        | 120       | 140       | 160  |
| 0.61 - 1.0       | ≤ 0.5         | 1                | 5         | 10        | 25        | 40        | 60        | 90        | 100  |
|                  | 0.51 - 1.0    | 5                | 10        | 15        | 30        | 50        | 80        | 110       | 130  |
|                  | 1.1 - 2.0     | 10               | 185       | 30        | 50        | 80        | 100       | 130       | 150  |
|                  | 2.1 - 4.0     | 15               | 30        | 50        | 80        | 100       | 120       | 140       | 170  |
|                  | > 4.0         | 25               | 40        | 60        | 100       | 120       | 150       | 180       | 200  |
| 1.1 - 2.0        | ≤ 0.5         | 2                | 5         | 15        | 30        | 50        | 80        | 110       | 130  |
|                  | 0.51 - 1.0    | 7                | 10        | 20        | 35        | 55        | 100       | 130       | 50   |
|                  | 1.1 - 2.0     | 15               | 20        | 35        | 55        | 100       | 120       | 140       | 170  |
|                  | 2.1 - 4.0     | 20               | 30        | 55        | 85        | 110       | 150       | 170       | 200  |
|                  | > 4.0         | 30               | 45        | 75        | 120       | 140       | 180       | 200       | 260  |
| 2.1 - 3.0        | ≤ 0.5         | 2                | 7         | 20        | 35        | 55        | 95        | 130       | 150  |
|                  | 0.51-1.0      | 7                | 10        | 30        | 45        | 60        | 120       | 140       | 170  |
|                  | 1.1 - 2.0     | 15               | 20        | 40        | 60        | 75        | 140       | 170       | 200  |
|                  | 2.1 - 4.0     | 20               | 35        | 60        | 90        | 120       |           |           |      |
|                  | > 4.0         | 35               | 50        | 80        | 120       | 150       | 200       | 260       | 280  |
| > 3.0            | ≤ 0.5         | 2                | 8         | 20        | 40        | 60        | 100       | 140       | 160  |
|                  | 0.51-1.0      | 8                | 15        | 25        | 45        | 65        | 120       | 150       | 170  |
|                  | 1.1 -2.0      | 20               | 25        | 35        | 65        | 120       | 150       | 180       | 200  |
|                  | 2.1 - 4.0     | 30               | 60        | 60        | 120       | 150       | 160       | 240       | 240  |
|                  | > 4.0         | 40               | 80        | 100       | 160       | 180       | 200       | 280       | 300  |

Table G-18—Estimated Corrosion Rates for 1<sup>1</sup>/<sub>4</sub> and 2<sup>1</sup>/<sub>4</sub> Cr Steel (mpy)

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |         |         |         |         |         |         |       |
|------------------|---------------|------------------|---------|---------|---------|---------|---------|---------|-------|
|                  |               | ≤ 450            | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | > 750 |
| ≤ 0.2            | ≤ 0.3         | 1                | 1       | 4       | 7       | 13      | 21      | 25      | 30    |
|                  | 0.31-1.0      | 3                | 8       | 15      | 20      | 25      | 30      | 35      | 40    |
|                  | 1.1-2.0       | 10               | 15      | 20      | 30      | 60      | 75      | 90      | 100   |
|                  | 2.1-4.0       | 15               | 30      | 30      | 60      | 75      | 85      | 120     | 120   |
|                  | > 4.0         | 20               | 40      | 50      | 80      | 100     | 120     | 140     | 160   |
| 0.21–0.6         | ≤ 0.5         | 1                | 2       | 5       | 10      | 20      | 30      | 35      | 40    |
|                  | 0.51 - 1.0    | 2                | 5       | 8       | 15      | 20      | 30      | 40      | 45    |
|                  | 1.1 - 2.0     | 4                | 8       | 15      | 20      | 25      | 40      | 45      | 55    |
|                  | 2.1 - 4.0     | 5                | 10      | 20      | 25      | 35      | 50      | 60      | 65    |
|                  | > 4.0         | 10               | 15      | 25      | 35      | 45      | 60      | 70      | 80    |
| 0.61–1.0         | ≤ 0.5         | 1                | 3       | 6       | 15      | 25      | 40      | 45      | 50    |
|                  | 0.51 - 1.0    | 3                | 5       | 8       | 20      | 30      | 45      | 55      | 60    |
|                  | 1.1-2.0       | 5                | 8       | 15      | 25      | 40      | 50      | 65      | 75    |
|                  | 2.1 - 4.0     | 7                | 15      | 25      | 40      | 50      | 60      | 70      | 85    |
|                  | > 4.0         | 12               | 20      | 30      | 50      | 60      | 75      | 90      | 100   |
| 1.1–2.0          | ≤ 0.5         | 2                | 3       | 8       | 15      | 30      | 50      | 55      | 65    |
|                  | 0.51 - 1.0    | 4                | 5       | 10      | 20      | 40      | 55      | 65      | 75    |
|                  | 1.1 - 2.0     | 6                | 10      | 20      | 30      | 50      | 65      | 70      | 80    |
|                  | 2.1-4.0       | 10               | 15      | 30      | 45      | 60      | 75      | 85      | 100   |
|                  | > 4.0         | 15               | 20      | 35      | 60      | 75      | 90      | 100     | 130   |
| 2.1–3.0          | ≤ 0.5         | 2                | 4       | 9       | 20      | 35      | 55      | 65      | 75    |
|                  | 0.51 - 1.0    | 4                | 5       | 15      | 25      | 40      | 60      | 70      | 80    |
|                  | 1.1 - 2.0     | 7                | 10      | 20      | 30      | 45      | 70      | 80      | 100   |
|                  | 2.1-4.0       | 10               | 15      | 30      | 45      | 60      | 80      | 100     | 120   |
|                  | > 4.0         | 15               | 25      | 40      | 60      | 80      | 100     | 120     | 140   |
| > 3.0            | ≤ 0.5         | 2                | 4       | 10      | 20      | 35      | 60      | 70      | 80    |
|                  | 0.51-1.0      | 5                | 8       | 15      | 25      | 40      | 70      | 75      | 85    |
|                  | 1.1-2.0       | 10               | 15      | 20      | 30      | 60      | 75      | 90      | 100   |
|                  | 2.1 - 4.0     | 15               | 30      | 30      | 60      | 75      | 85      | 120     | 120   |
|                  | > 4.0         | 20               | 40      | 50      | 80      | 100     | 120     | 140     | 160   |

Table G-19—Estimated Corrosion Rates for 5% Cr Steel (mpy)

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |         |         |         |         |         |         |      |
|------------------|---------------|------------------|---------|---------|---------|---------|---------|---------|------|
|                  |               | 450              | 451-500 | 501-550 | 551-600 | 601-650 | 651-700 | 701-750 | >750 |
| ≤0.2             | ≤0.7          | 1                | 1       | 2       | 4       | 6       | 8       | 10      | 15   |
|                  | 0.71-1.5      | 2                | 3       | 4       | 6       | 10      | 10      | 15      | 20   |
|                  | 1.6-2.0       | 7                | 10      | 15      | 20      | 25      | 35      | 45      | 50   |
|                  | 2.1-4.0       | 10               | 15      | 20      | 30      | 40      | 45      | 50      | 60   |
|                  | >4.0          | 15               | 20      | 30      | 40      | 50      | 60      | 70      | 80   |
| 0.2-0.6          | ≤0.7          | 1                | 2       | 3       | 5       | 8       | 10      | 15      | 20   |
|                  | 0.71 - 1.5    | 2                | 3       | 4       | 6       | 10      | 15      | 20      | 25   |
|                  | 1.6 - 2.0     | 2                | 4       | 6       | 8       | 15      | 20      | 25      | 30   |
|                  | 2.1 - 4.0     | 4                | 6       | 8       | 10      | 15      | 20      | 30      | 35   |
|                  | >4.0          | 6                | 8       | 10      | 10      | 20      | 25      | 35      | 40   |
| 0.61-1.0         | ≤0.7          | 1                | 2       | 4       | 6       | 10      | 15      | 23      | 25   |
|                  | 0.71 - 1.5    | 2                | 4       | 6       | 8       | 15      | 20      | 25      | 30   |
|                  | 1.6 - 2.0     | 4                | 6       | 8       | 10      | 15      | 20      | 30      | 35   |
|                  | 2.1 - 4.0     | 6                | 8       | 10      | 10      | 20      | 25      | 35      | 40   |
|                  | >4.0          | 8                | 10      | 10      | 15      | 20      | 30      | 40      | 50   |
| 1.1-2.0          | ≤0.7          | 1                | 2       | 5       | 8       | 15      | 20      | 30      | 35   |
|                  | 0.71-1.5      | 3                | 5       | 10      | 15      | 20      | 30      | 35      | 40   |
|                  | 1.6-2.0       | 5                | 10      | 15      | 20      | 30      | 35      | 40      | 45   |
|                  | 2.1-4.0       | 10               | 15      | 20      | 30      | 35      | 40      | 45      | 50   |
|                  | >4.0          | 15               | 20      | 30      | 35      | 40      | 50      | 60      | 70   |
| 2.1-3.0          | ≤0.7          | 1                | 3       | 6       | 9       | 15      | 20      | 35      | 40   |
|                  | 0.71-1.5      | 5                | 7       | 10      | 15      | 20      | 25      | 40      | 45   |
|                  | 1.6-2.0       | 7                | 10      | 15      | 20      | 25      | 35      | 45      | 50   |
|                  | 2.1 - 4.0     | 10               | 15      | 20      | 30      | 40      | 45      | 50      | 60   |
|                  | >4.0          | 15               | 20      | 30      | 40      | 50      | 60      | 70      | 80   |
| >3.0             | ≤0.7          | 2                | 3       | 6       | 10      | 15      | 25      | 35      | 40   |
|                  | 0.71-1.5      | 5                | 7       | 10      | 15      | 20      | 30      | 40      | 45   |
|                  | 1.6-2.0       | 7                | 10      | 15      | 20      | 25      | 35      | 45      | 50   |
|                  | 2.1-4.0       | 10               | 15      | 20      | 30      | 40      | 45      | 50      | 60   |
|                  | >4.0          | 15               | 20      | 30      | 40      | 50      | 60      | 70      | 80   |

Table G-20—Estimated Corrosion Rates for 7% Cr Steel (mpy)

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |         |         |         |         |         |         |       |
|------------------|---------------|------------------|---------|---------|---------|---------|---------|---------|-------|
|                  |               | ≤ 450            | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | > 750 |
| ≤ 0.2            | ≤ 0.7         | 1                | 1       | 1       | 2       | 4       | 6       | 7       | 8     |
|                  | 0.71-1.5      | 1                | 2       | 3       | 5       | 7       | 8       | 10      | 15    |
|                  | 1.6-2.0       | 4                | 7       | 10      | 15      | 20      | 25      | 30      | 35    |
|                  | 2.1-4.0       | 7                | 10      | 15      | 20      | 25      | 30      | 35      | 45    |
|                  | > 4.0         | 10               | 15      | 20      | 25      | 30      | 35      | 45      | 60    |
| 0.21–0.6         | ≤ 0.7         | 1                | 1       | 2       | 4       | 5       | 8       | 10      | 15    |
|                  | 0.71-1.5      | 1                | 2       | 4       | 5       | 8       | 10      | 15      | 15    |
|                  | 1.6-2.0       | 2                | 4       | 5       | 6       | 10      | 15      | 15      | 20    |
|                  | 2.1-4.0       | 3                | 5       | 6       | 9       | 12      | 15      | 20      | 20    |
|                  | > 4.0         | 4                | 6       | 9       | 10      | 15      | 20      | 20      | 25    |
| 0.61–1.0         | ≤ 0.7         | 1                | 1       | 3       | 4       | 6       | 10      | 15      | 15    |
|                  | 0.71-1.5      | 2                | 3       | 4       | 6       | 10      | 15      | 15      | 20    |
|                  | 1.6-2.0       | 3                | 4       | 6       | 10      | 12      | 15      | 20      | 25    |
|                  | 2.1-4.0       | 4                | 6       | 10      | 12      | 15      | 20      | 25      | 30    |
|                  | > 4.0         | 5                | 10      | 12      | 15      | 20      | 25      | 30      | 35    |
| 1.1–2.0          | ≤ 0.7         | 1                | 2       | 3       | 6       | 8       | 15      | 15      | 20    |
|                  | 0.71 - 1.5    | 2                | 3       | 6       | 10      | 15      | 15      | 20      | 25    |
|                  | 1.6-2.0       | 3                | 6       | 10      | 15      | 20      | 20      | 25      | 30    |
|                  | 2.1-4.0       | 6                | 10      | 15      | 20      | 20      | 25      | 30      | 35    |
|                  | > 4.0         | 10               | 15      | 20      | 20      | 25      | 30      | 35      | 45    |
| 2.1–3.0          | ≤ 0.7         | 1                | 2       | 4       | 6       | 9       | 15      | 20      | 25    |
|                  | 0.71-1.5      | 6                | 7       | 9       | 10      | 15      | 20      | 25      | 30    |
|                  | 1.6-2.0       | 7                | 9       | 10      | 15      | 20      | 25      | 30      | 35    |
|                  | 2.1-4.0       | 9                | 10      | 15      | 20      | 30      | 35      | 35      | 40    |
|                  | > 4.0         | 10               | 15      | 20      | 30      | 35      | 470     | 50      | 55    |
| > 3.0            | ≤ 0.7         | 1                | 2       | 4       | 7       | 10      | 15      | 20      | 25    |
|                  | > 0.7         | 1                | 2       | 4       | 7       | 10      | 15      | 20      | 25    |
|                  | 0.71 - 1.5    | 2                | 4       | 7       | 10      | 15      | 20      | 25      | 30    |
|                  | 1.60 - 2.0    | 4                | 7       | 10      | 15      | 20      | 25      | 30      | 35    |
|                  | 2.1 - 4.0     | 7                | 10      | 15      | 20      | 25      | 30      | 35      | 45    |
|                  | > 4.0         | 10               | 15      | 20      | 25      | 30      | 35      | 45      | 60    |

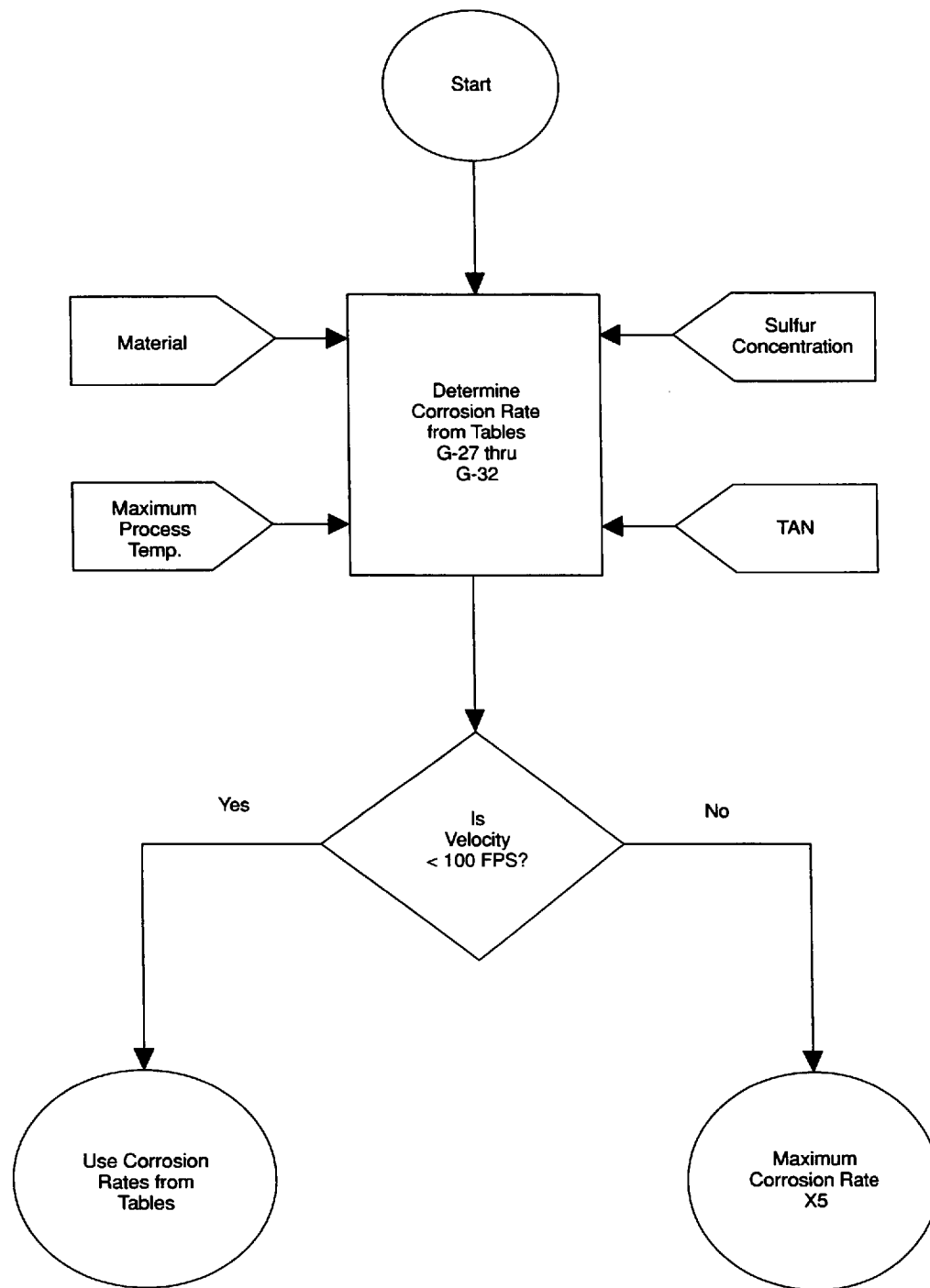


Figure G-3—Determination of High Temperature Sulfidic and Naphthenic Acid Corrosion Rates



Table G-21—Estimated Corrosion Rates for 9% Cr Steel (mpy)

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |         |         |         |         |         |         |       |
|------------------|---------------|------------------|---------|---------|---------|---------|---------|---------|-------|
|                  |               | ≤ 450            | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | > 750 |
| ≤ 0.2            | ≤ 0.7         | 1                | 1       | 1       | 2       | 3       | 4       | 5       | 6     |
|                  | 0.71-1.5      | 1                | 2       | 2       | 4       | 4       | 5       | 6       | 8     |
|                  | 1.6-2.1       | 2                | 4       | 5       | 8       | 10      | 15      | 15      | 20    |
|                  | 2.1-4.0       | 3                | 6       | 10      | 12      | 15      | 20      | 20      | 25    |
|                  | > 4.0         | 5                | 8       | 12      | 15      | 20      | 25      | 30      | 30    |
| 0.21–0.6         | ≤ 0.7         | 1                | 1       | 2       | 3       | 4       | 6       | 7       | 8     |
|                  | 0.71-1.5      | 1                | 1       | 2       | 4       | 5       | 7       | 8       | 10    |
|                  | 1.6-2.1       | 2                | 2       | 3       | 5       | 8       | 8       | 10      | 10    |
|                  | 2.1-4.0       | 3                | 3       | 5       | 8       | 10      | 10      | 12      | 15    |
|                  | > 4.0         | 4                | 5       | 8       | 10      | 10      | 12      | 15      | 15    |
| 0.61–1.0         | ≤ 0.7         | 1                | 1       | 2       | 3       | 5       | 8       | 9       | 10    |
|                  | 0.71-1.5      | 1                | 2       | 3       | 5       | 8       | 10      | 10      | 10    |
|                  | 1.6-2.1       | 2                | 3       | 5       | 8       | 10      | 10      | 10      | 15    |
|                  | 2.1-4.0       | 3                | 5       | 8       | 10      | 10      | 15      | 15      | 15    |
|                  | > 4.0         | 5                | 8       | 10      | 10      | 15      | 15      | 20      | 20    |
| 1.1–2.0          | ≤ 0.7         | 1                | 1       | 2       | 4       | 6       | 10      | 10      | 15    |
|                  | 0.71-1.5      | 1                | 2       | 3       | 5       | 7       | 10      | 15      | 15    |
|                  | 1.6-2.1       | 2                | 4       | 4       | 6       | 8       | 12      | 15      | 20    |
|                  | 2.1-4.0       | 3                | 6       | 5       | 8       | 10      | 15      | 20      | 20    |
|                  | > 4.0         | 5                | 8       | 10      | 12      | 15      | 20      | 20      | 25    |
| 2.1–3.0          | ≤ 0.7         | 1                | 1       | 3       | 5       | 7       | 10      | 15      | 15    |
|                  | 0.71-1.5      | 1                | 2       | 4       | 6       | 8       | 10      | 15      | 15    |
|                  | 1.6-2.1       | 2                | 4       | 5       | 8       | 10      | 15      | 15      | 20    |
|                  | 2.1-4.0       | 3                | 6       | 10      | 12      | 15      | 20      | 20      | 25    |
|                  | > 4.0         | 5                | 8       | 12      | 15      | 20      | 25      | 30      | 30    |
| > 3.0            | ≤ 0.7         | 1                | 1       | 2       | 5       | 8       | 10      | 15      | 15    |
|                  | 0.71-1.5      | 2                | 3       | 5       | 8       | 10      | 15      | 15      | 20    |
|                  | 1.6-2.1       | 3                | 5       | 10      | 12      | 15      | 20      | 20      | 25    |
|                  | 2.1-4.0       | 5                | 8       | 12      | 15      | 20      | 25      | 30      | 30    |
|                  | > 4.0         | 7                | 9       | 15      | 20      | 25      | 30      | 35      | 40    |

Table G-22—Estimated Corrosion Rates for 12% Cr Steel (mpy)

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |         |         |         |         |         |         |       |
|------------------|---------------|------------------|---------|---------|---------|---------|---------|---------|-------|
|                  |               | ≤ 450            | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | > 750 |
| ≤ 0.2            | ≤ 0.7         | 1                | 1       | 1       | 1       | 1       | 1       | 2       | 2     |
|                  | 0.71-1.5      | 1                | 1       | 1       | 1       | 1       | 2       | 4       | 5     |
|                  | 1.6-2.0       | 2                | 2       | 2       | 4       | 4       | 5       | 8       | 10    |
|                  | 2.1-4.0       | 5                | 10      | 15      | 20      | 25      | 30      | 25      | 40    |
|                  | > 4.0         | 10               | 15      | 20      | 25      | 30      | 25      | 40      | 45    |
| 0.2–0.6          | ≤ 0.7         | 1                | 1       | 1       | 1       | 1       | 2       | 3       | 3     |
|                  | 0.71-1.5      | 1                | 1       | 1       | 1       | 1       | 2       | 3       | 3     |
|                  | 1.6-2.0       | 1                | 2       | 2       | 2       | 2       | 4       | 5       | 5     |
|                  | 2.1-4.0       | 2                | 3       | 3       | 3       | 3       | 5       | 10      | 15    |
|                  | > 4.0         | 3                | 4       | 5       | 8       | 10      | 12      | 15      | 20    |
| 0.61–1.0         | ≤ 0.7         |                  | 1       | 1       | 1       | 1       | 2       | 3       | 4     |
|                  | 0.71-1.5      | 1                | 1       | 1       | 1       | 1       | 2       | 3       | 4     |
|                  | 1.6-2.0       | 2                | 2       | 4       | 5       | 6       | 6       | 7       | 8     |
|                  | 2.1-4.0       | 3                | 3       | 5       | 8       | 10      | 12      | 15      | 20    |
|                  | > 4.0         | 4                | 5       | 5       | 8       | 10      | 15      | 20      | 25    |
| 1.1–2.0          | ≤ 0.7         | 1                | 1       | 1       | 1       | 2       | 3       | 4       | 5     |
|                  | 0.71-1.5      | 1                | 1       | 1       | 1       | 2       | 3       | 4       | 5     |
|                  | 1.6-2.0       | 2                | 2       | 3       | 5       | 7       | 8       | 10      | 10    |
|                  | 2.1-4.0       | 3                | 3       | 5       | 8       | 10      | 12      | 15      | 20    |
|                  | > 4.0         | 5                | 8       | 10      | 12      | 15      | 20      | 25      | 30    |
| 2.1–3.0          | ≤ 0.7         | 1                | 1       | 1       | 1       | 2       | 3       | 5       | 6     |
|                  | 0.71-1.5      | 1                | 1       | 1       | 1       | 2       | 3       | 5       | 6     |
|                  | 1.6-2.0       | 2                | 5       | 7       | 9       | 10      | 12      | 15      | 15    |
|                  | 2.1-4.0       | 3                | 8       | 10      | 15      | 20      | 20      | 25      | 30    |
|                  | > 4.0         | 5                | 10      | 15      | 20      | 25      | 30      | 35      | 40    |
| > 3.0            | ≤ 0.7         | 1                | 1       | 1       | 1       | 2       | 3       | 5       | 6     |
|                  | 0.71-1.5      | 1                | 1       | 1       | 1       | 2       | 4       | 5       | 6     |
|                  | 1.6-2.0       | 3                | 5       | 7       | 9       | 10      | 12      | 15      | 15    |
|                  | 2.1-4.0       | 4                | 8       | 10      | 15      | 20      | 20      | 25      | 30    |
|                  | > 4.0         | 5                | 10      | 15      | 20      | 25      | 30      | 35      | 40    |

Table G-23—Estimated Corrosion Rates for Austenitic SS without Mo (mpy)<sup>a</sup>

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |         |         |         |         |         |         |       |
|------------------|---------------|------------------|---------|---------|---------|---------|---------|---------|-------|
|                  |               | ≤ 450            | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | > 750 |
| ≤ 0.2            | ≤ 1.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 1.1–2.0       | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 1       | 2       | 3       | 4       | 4     |
|                  | > 4.0         | 1                | 1       | 1       | 2       | 3       | 4       | 5       | 6     |
| 0.21–0.6         | ≤ 1.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 1.1–2.0       | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 1       | 2       | 3       | 4       | 4     |
|                  | > 4.0         | 1                | 1       | 1       | 2       | 3       | 4       | 5       | 6     |
| 0.61–1.0         | ≤ 1.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 1.1–2.0       | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 2       | 3       | 4       | 5       | 6     |
|                  | > 4.0         | 1                | 2       | 2       | 4       | 6       | 8       | 10      | 12    |
| 1.0–2.0          | ≤ 1.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 1.1–2.0       | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 2       | 3       | 4       | 5       | 6     |
|                  | > 4.0         | 1                | 2       | 2       | 4       | 6       | 8       | 10      | 12    |
| 2.1–3.0          | ≤ 1.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 1.1–2.0       | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 2       | 2       | 4       | 6       | 8       | 10      | 12    |
|                  | > 4.0         | 1                | 2       | 4       | 7       | 10      | 14      | 17      | 20    |
| > 3.0            | ≤ 1.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 2     |
|                  | 1.1–2.0       | 1                | 1       | 1       | 1       | 1       | 2       | 2       | 2     |
|                  | 2.1–4.0       | 1                | 2       | 2       | 4       | 6       | 8       | 10      | 12    |
|                  | > 4.0         | 1                | 2       | 4       | 7       | 10      | 14      | 17      | 20    |

<sup>a</sup>Austenitic stainless steels without Mo include 304, 304L, 321, 347, etc.

Table G-24—Estimated Corrosion Rates for 316 SS with < 2.5% Mo (mpy)<sup>a</sup>

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |         |         |         |         |         |         |       |
|------------------|---------------|------------------|---------|---------|---------|---------|---------|---------|-------|
|                  |               | ≤ 450            | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | > 750 |
| ≤ 0.2            | ≤ 0.2         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 1       | 1       | 2       | 2       | 2     |
|                  | > 4.0         | 1                | 1       | 1       | 2       | 4       | 5       | 7       | 10    |
| 0.21–0.6         | ≤ 0.2         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 1       | 2       | 2       | 2       | 2     |
|                  | > 4.0         | 1                | 1       | 2       | 3       | 4       | 5       | 7       | 10    |
| 0.61–1.0         | ≤ 0.2         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 1       | 2       | 2       | 2       | 3     |
|                  | > 4.0         | 1                | 1       | 2       | 3       | 5       | 5       | 7       | 10    |
| 1.1–2.0          | ≤ 0.2         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 1       | 3       | 3       | 3       | 4     |
|                  | > 4.0         | 1                | 1       | 3       | 5       | 5       | 5       | 7       | 10    |
| 2.1–3.0          | ≤ 0.2         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 2       | 3       | 3       | 4       | 5     |
|                  | > 4.0         | 1                | 1       | 3       | 5       | 5       | 6       | 8       | 10    |
| > 3.0            | ≤ 0.2         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 2     |
|                  | 2.1–4.0       | 1                | 1       | 1       | 2       | 4       | 5       | 5       | 6     |
|                  | > 4.0         | 1                | 2       | 3       | 5       | 5       | 6       | 8       | 10    |

<sup>a</sup>Includes stainless steels with < 2.5% Mo, for example 316, 316L, 316H, etc.

Table G-25—Estimated Corrosion Rates for 316 SS with ≥ 2.5% Mo and 317 SS (mpy)

| Sulfur<br>(wt.%) | TAN<br>(mg/g) | Temperature (°F) |         |         |         |         |         |         |       |
|------------------|---------------|------------------|---------|---------|---------|---------|---------|---------|-------|
|                  |               | ≤ 450            | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | > 750 |
| ≤ 0.2            | ≤ 4.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 4.1–6.0       | 1                | 1       | 1       | 1       | 1       | 2       | 4       | 5     |
|                  | > 6.0         | 1                | 1       | 1       | 2       | 4       | 5       | 7       | 10    |
| 0.21–0.6         | ≤ 4.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 4.1–6.0       | 1                | 1       | 1       | 1       | 2       | 4       | 4       | 5     |
|                  | > 6.0         | 1                | 1       | 2       | 3       | 4       | 5       | 7       | 10    |
| 0.61–1.0         | ≤ 4.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 4.1–6.0       | 1                | 1       | 1       | 1       | 2       | 4       | 4       | 5     |
|                  | > 6.0         | 1                | 1       | 2       | 3       | 4       | 5       | 7       | 10    |
| 1.1–2.0          | ≤ 4.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 4.1–6.0       | 1                | 1       | 1       | 1       | 2       | 3       | 5       | 7     |
|                  | > 6.0         | 1                | 1       | 3       | 5       | 5       | 5       | 7       | 10    |
| 2.1–3.0          | ≤ 4.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1     |
|                  | 4.1–6.0       | 1                | 1       | 1       | 2       | 3       | 4       | 5       | 7     |
|                  | > 6.0         | 1                | 1       | 3       | 5       | 5       | 6       | 8       | 10    |
| > 3.0            | ≤ 4.0         | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 2     |
|                  | 4.1–6.0       | 1                | 1       | 1       | 2       | 3       | 4       | 5       | 7     |
|                  | > 6.0         | 1                | 2       | 3       | 5       | 5       | 6       | 8       | 10    |

Table G-26—Basic Data Required for Analysis of High Temperature H<sub>2</sub>S/H<sub>2</sub> Corrosion

| Basic Data                                          | Comments                                                                                                                                                                                                    |
|-----------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Material of Construction                            | Determine the material of construction of the equipment/piping.                                                                                                                                             |
| Type of Hydrocarbon Present<br>(naphtha or gas oil) | Use “naphtha” for naphtha and light distillates (e.g. kerosene/diesel/jet). Use “gas oil” for all other hydrocarbons (atmospheric gas oils and heavier) and for H <sub>2</sub> without hydrocarbon present. |
| Maximum Temperature (°F)                            | Determine the maximum process temperature.                                                                                                                                                                  |
| H <sub>2</sub> S Content of the Vapor<br>(mole %)   | Determine the H <sub>2</sub> S content in the vapor.<br>Note that mole% = volume % (not wt.%)                                                                                                               |

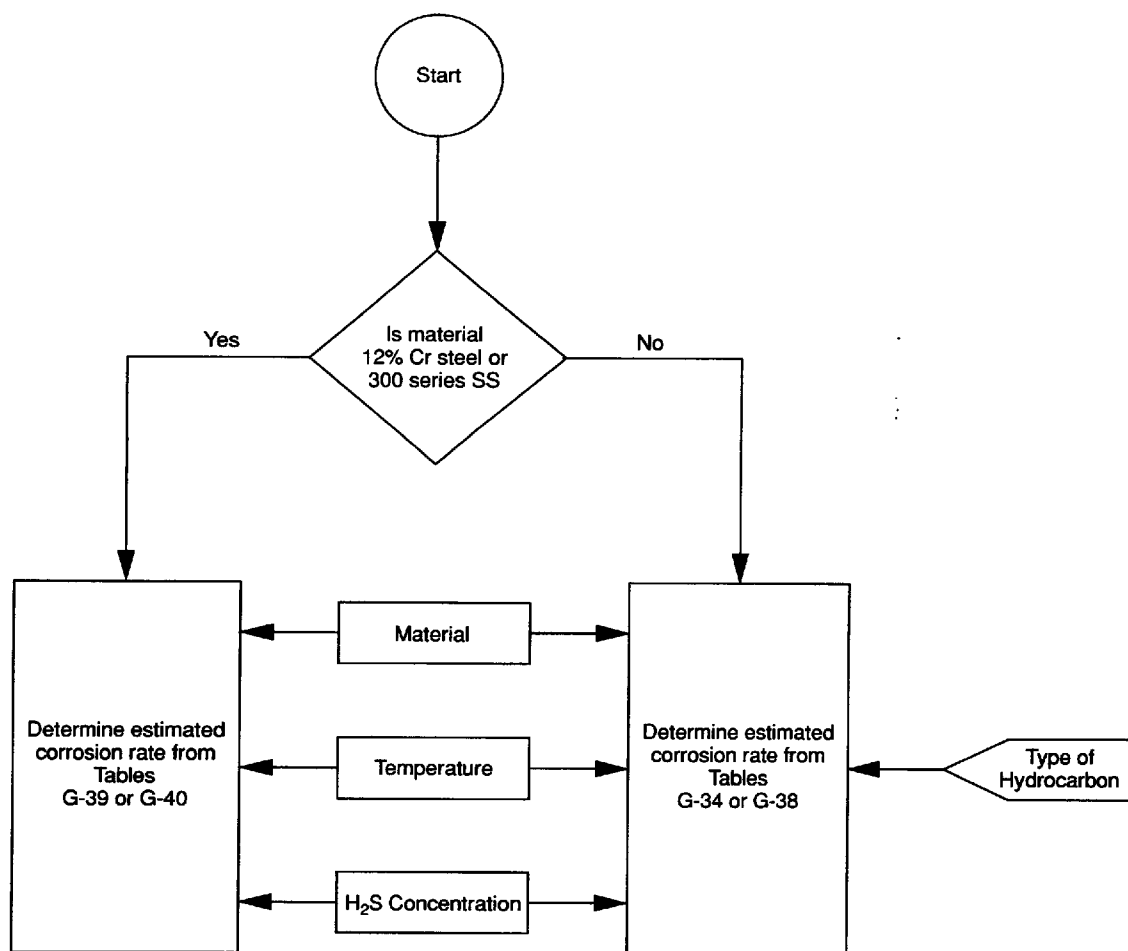


Figure G-4—Determination of High Temperature H<sub>2</sub>S/H<sub>2</sub> Corrosion Rates

Table G-27—Estimated Corrosion Rates for Carbon Steel, 1<sup>1</sup>/<sub>4</sub> Cr and 2<sup>1</sup>/<sub>4</sub> Cr Steels (mpy)

| H <sub>2</sub> S<br>(mole %) | Type of<br>Hydro-<br>Carbon | Temperature (°F) |         |         |         |         |         |         |         |         |         |         |          |
|------------------------------|-----------------------------|------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
|                              |                             | 400–450          | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | 751–800 | 801–850 | 851–900 | 901–950 | 951–1000 |
| < 0.002                      | Naphtha                     | 1                | 1       | 1       | 1       | 2       | 3       | 4       | 6       | 8       | 10      | 14      | 18       |
|                              | Gas Oil                     | 1                | 1       | 1       | 2       | 3       | 5       | 7       | 10      | 14      | 20      | 26      | 34       |
| 0.002 to<br>0.005            | Naphtha                     | 1                | 2       | 3       | 4       | 7       | 11      | 16      | 22      | 31      | 41      | 55      | 71       |
|                              | Gas Oil                     | 1                | 2       | 3       | 4       | 7       | 11      | 16      | 22      | 31      | 41      | 55      | 71       |
| 0.006 to<br>0.01             | Naphtha                     | 1                | 1       | 2       | 3       | 5       | 7       | 11      | 15      | 21      | 29      | 38      | 50       |
|                              | Gas Oil                     | 1                | 2       | 4       | 6       | 9       | 14      | 21      | 29      | 41      | 55      | 73      | 94       |
| 0.02 to<br>0.05              | Naphtha                     | 1                | 2       | 3       | 5       | 9       | 13      | 19      | 27      | 38      | 51      | 67      | 87       |
|                              | Gas Oil                     | 2                | 4       | 6       | 10      | 16      | 25      | 36      | 51      | 71      | 96      | 130     | 170      |
| 0.06 to<br>0.1               | Naphtha                     | 1                | 2       | 4       | 7       | 10      | 16      | 23      | 33      | 46      | 62      | 82      | 110      |
|                              | Gas Oil                     | 2                | 4       | 8       | 13      | 20      | 30      | 44      | 63      | 87      | 120     | 160     | 200      |
| 0.11 to<br>0.5               | Naphtha                     | 2                | 3       | 6       | 10      | 15      | 23      | 34      | 48      | 66      | 90      | 120     | 150      |
|                              | Gas Oil                     | 3                | 6       | 11      | 18      | 29      | 44      | 64      | 91      | 130     | 170     | 230     | 300      |
| 0.51 to 1                    | Naphtha                     | 2                | 4       | 7       | 11      | 17      | 26      | 38      | 54      | 75      | 100     | 130     | 170      |
|                              | Gas Oil                     | 4                | 7       | 12      | 21      | 32      | 49      | 72      | 100     | 140     | 190     | 250     | 330      |
| > 1                          | Naphtha                     | 3                | 5       | 8       | 13      | 21      | 32      | 47      | 67      | 93      | 130     | 170     | 220      |
|                              | Gas Oil                     | 5                | 9       | 15      | 26      | 40      | 61      | 89      | 130     | 180     | 240     | 310     | 410      |

Table G-28—Estimated Corrosion Rates for 5% Cr Steel (mpy)

| H <sub>2</sub> S<br>(mole %) | Type of<br>Hydro-<br>Carbon | Temperature (°F) |         |         |         |         |         |         |         |         |         |         |          |
|------------------------------|-----------------------------|------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
|                              |                             | 400–450          | 450–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | 751–800 | 801–850 | 851–900 | 901–950 | 951–1000 |
| < 0.002                      | Naphtha                     | 1                | 1       | 1       | 1       | 1       | 2       | 3       | 4       | 6       | 8       | 11      | 14       |
|                              | Gas Oil                     | 1                | 1       | 1       | 2       | 3       | 4       | 6       | 8       | 12      | 16      | 21      | 27       |
| 0.002 to<br>0.005            | Naphtha                     | 1                | 1       | 1       | 2       | 3       | 5       | 7       | 9       | 13      | 18      | 23      | 30       |
|                              | Gas Oil                     | 1                | 1       | 2       | 4       | 6       | 9       | 13      | 18      | 25      | 33      | 44      | 57       |
| 0.006 to<br>0.01             | Naphtha                     | 1                | 1       | 2       | 2       | 4       | 6       | 9       | 12      | 17      | 23      | 31      | 40       |
|                              | Gas Oil                     | 1                | 2       | 3       | 5       | 7       | 11      | 17      | 24      | 33      | 44      | 58      | 76       |
| 0.011 to<br>0.05             | Naphtha                     | 1                | 2       | 3       | 4       | 7       | 10      | 15      | 22      | 30      | 41      | 54      | 70       |
|                              | Gas Oil                     | 2                | 3       | 5       | 8       | 13      | 20      | 29      | 41      | 57      | 77      | 100     | 130      |
| 0.051 to<br>0.1              | Naphtha                     | 1                | 2       | 3       | 5       | 8       | 13      | 19      | 27      | 37      | 50      | 66      | 85       |
|                              | Gas Oil                     | 2                | 4       | 6       | 10      | 16      | 24      | 36      | 51      | 70      | 94      | 130     | 160      |
| 0.11 to<br>0.5               | Naphtha                     | 1                | 3       | 5       | 8       | 12      | 18      | 27      | 39      | 53      | 72      | 95      | 120      |
|                              | Gas Oil                     | 3                | 5       | 9       | 15      | 23      | 35      | 52      | 73      | 100     | 140     | 180     | 240      |
| 0.51 to 1                    | Naphtha                     | 2                | 3       | 5       | 9       | 14      | 21      | 31      | 44      | 60      | 81      | 110     | 140      |
|                              | Gas Oil                     | 3                | 6       | 10      | 17      | 26      | 40      | 58      | 82      | 110     | 150     | 200     | 270      |
| > 1                          | Naphtha                     | 2                | 4       | 7       | 11      | 17      | 26      | 38      | 54      | 75      | 100     | 130     | 170      |
|                              | Gas Oil                     | 4                | 7       | 12      | 21      | 32      | 49      | 72      | 100     | 140     | 190     | 250     | 330      |

Table G-29—Estimated Corrosion Rates for 7% Cr Steel (mpy)

| H <sub>2</sub> S<br>(mole%) | Type of<br>Hydro-<br>Carbon | Temperature (°F) |         |         |         |         |         |         |         |         |         |         |          |
|-----------------------------|-----------------------------|------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
|                             |                             | 400–450          | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | 751–800 | 801–850 | 851–900 | 901–950 | 951–1000 |
| < 0.002                     | Naphtha                     | 1                | 1       | 1       | 1       | 1       | 2       | 3       | 4       | 6       | 8       | 10      | 13       |
|                             | Gas Oil                     | 1                | 1       | 1       | 2       | 2       | 4       | 5       | 8       | 11      | 14      | 19      | 25       |
| 0.002 to<br>0.005           | Naphtha                     | 1                | 1       | 1       | 2       | 3       | 4       | 6       | 9       | 12      | 16      | 21      | 28       |
|                             | Gas Oil                     | 1                | 1       | 2       | 3       | 5       | 8       | 11      | 16      | 23      | 30      | 40      | 52       |
| 0.006 to<br>0.01            | Naphtha                     | 1                | 1       | 1       | 2       | 4       | 5       | 8       | 11      | 16      | 21      | 28      | 37       |
|                             | Gas Oil                     | 1                | 2       | 3       | 4       | 7       | 10      | 15      | 22      | 30      | 40      | 53      | 69       |
| 0.02 to<br>0.05             | Naphtha                     | 1                | 1       | 2       | 4       | 6       | 10      | 14      | 20      | 28      | 37      | 49      | 64       |
|                             | Gas Oil                     | 1                | 3       | 5       | 8       | 12      | 18      | 27      | 38      | 52      | 71      | 4       | 120      |
| 0.06 to<br>0.1              | Naphtha                     | 1                | 2       | 3       | 5       | 8       | 12      | 17      | 24      | 34      | 46      | 60      | 78       |
|                             | Gas Oil                     | 2                | 3       | 6       | 9       | 15      | 22      | 33      | 46      | 64      | 86      | 110     | 150      |
| 0.2 to 0.5                  | Naphtha                     | 1                | 2       | 4       | 7       | 11      | 17      | 25      | 35      | 49      | 66      | 87      | 110      |
|                             | Gas Oil                     | 3                | 5       | 8       | 13      | 21      | 32      | 47      | 67      | 93      | 130     | 170     | 220      |
| 0.6 to 1                    | Naphtha                     | 2                | 3       | 5       | 8       | 13      | 19      | 28      | 40      | 55      | 74      | 98      | 130      |
|                             | Gas Oil                     | 3                | 5       | 9       | 15      | 24      | 36      | 53      | 76      | 100     | 140     | 190     | 240      |
| > 1                         | Naphtha                     | 2                | 3       | 6       | 10      | 16      | 24      | 35      | 49      | 68      | 92      | 120     | 160      |
|                             | Gas Oil                     | 4                | 7       | 11      | 19      | 30      | 45      | 66      | 94      | 130     | 180     | 230     | 300      |

Table G-30—Estimated Corrosion Rates for 9% Cr Steel (mpy)

| H <sub>2</sub> S<br>(mole %) | Type of<br>Hydro-<br>Carbon | Temperature (°F) |         |         |         |         |         |         |         |         |         |         |          |
|------------------------------|-----------------------------|------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
|                              |                             | 400–450          | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | 751–800 | 801–850 | 851–900 | 901–950 | 951–1000 |
| < 0.002                      | Naphtha                     | 1                | 1       | 1       | 1       | 1       | 2       | 3       | 4       | 5       | 7       | 9       | 12       |
|                              | Gas Oil                     | 1                | 1       | 1       | 1       | 2       | 3       | 5       | 7       | 10      | 13      | 17      | 23       |
| 0.002 to<br>0.005            | Naphtha                     | 1                | 1       | 1       | 2       | 2       | 4       | 6       | 8       | 11      | 15      | 17      | 25       |
|                              | Gas Oil                     | 1                | 1       | 2       | 3       | 5       | 7       | 11      | 15      | 21      | 28      | 37      | 48       |
| 0.006 to<br>0.01             | Naphtha                     | 1                | 1       | 1       | 2       | 3       | 5       | 7       | 10      | 14      | 20      | 26      | 34       |
|                              | Gas Oil                     | 1                | 1       | 2       | 4       | 6       | 10      | 14      | 20      | 27      | 37      | 49      | 64       |
| 0.02 to<br>0.05              | Naphtha                     | 1                | 1       | 2       | 4       | 6       | 9       | 13      | 18      | 25      | 34      | 45      | 59       |
|                              | Gas Oil                     | 1                | 2       | 4       | 7       | 11      | 17      | 24      | 35      | 48      | 65      | 86      | 110      |
| 0.06 to<br>0.1               | Naphtha                     | 1                | 2       | 3       | 4       | 7       | 11      | 16      | 22      | 31      | 42      | 55      | 72       |
|                              | Gas Oil                     | 2                | 3       | 5       | 9       | 13      | 20      | 30      | 42      | 59      | 79      | 110     | 140      |
| 0.2 to 0.5                   | Naphtha                     | 1                | 2       | 4       | 7       | 10      | 16      | 23      | 32      | 45      | 61      | 80      | 100      |
|                              | Gas Oil                     | 2                | 4       | 7       | 12      | 19      | 30      | 43      | 61      | 85      | 120     | 150     | 200      |
| 0.6 to 1                     | Naphtha                     | 1                | 3       | 4       | 7       | 12      | 18      | 26      | 37      | 51      | 68      | 90      | 120      |
|                              | Gas Oil                     | 3                | 5       | 8       | 14      | 22      | 33      | 49      | 69      | 96      | 130     | 170     | 220      |
| > 1                          | Naphtha                     | 2                | 3       | 6       | 9       | 14      | 22      | 32      | 45      | 63      | 85      | 110     | 150      |
|                              | Gas Oil                     | 3                | 6       | 10      | 17      | 27      | 41      | 60      | 86      | 120     | 160     | 210     | 280      |

Table G-31—Estimated Corrosion Rates for 12% Cr Steel (mpy)

| H <sub>2</sub> S (mole %) | Temperature (°F) |         |         |         |         |         |         |         |         |         |         |          |
|---------------------------|------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
|                           | 400–450          | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | 751–800 | 801–850 | 851–900 | 901–950 | 951–1000 |
| < 0.002                   | 1                | 1       | 1       | 1       | 2       | 3       | 4       | 5       | 6       | 9       | 11      | 14       |
| 0.002 to 0.005            | 1                | 1       | 1       | 1       | 2       | 3       | 4       | 6       | 8       | 11      | 14      | 18       |
| 0.006 to 0.01             | 1                | 1       | 1       | 2       | 2       | 4       | 5       | 7       | 9       | 12      | 15      | 19       |
| 0.02 to 0.05              | 1                | 1       | 1       | 2       | 3       | 4       | 6       | 9       | 12      | 15      | 19      | 25       |
| 0.06 to 0.1               | 1                | 1       | 1       | 2       | 3       | 5       | 7       | 10      | 13      | 17      | 22      | 27       |
| 0.2 to 0.5                | 1                | 1       | 2       | 3       | 4       | 6       | 9       | 12      | 16      | 21      | 27      | 34       |
| 0.6 to 1                  | 1                | 1       | 2       | 3       | 5       | 7       | 10      | 13      | 18      | 23      | 30      | 38       |
| > 1                       | 1                | 2       | 3       | 4       | 7       | 10      | 13      | 18      | 25      | 32      | 42      | 53       |

Table G-32—Estimated Corrosion Rates for 300 Series SS (mpy)

| H <sub>2</sub> S (mole %) | Temperature (°F) |         |         |         |         |         |         |         |         |         |         |          |
|---------------------------|------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
|                           | 400–450          | 451–500 | 501–550 | 551–600 | 601–650 | 651–700 | 701–750 | 751–800 | 801–850 | 851–900 | 901–950 | 951–1000 |
| < 0.002                   | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 2       | 2        |
| 0.002 to 0.005            | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 2       | 2       | 3        |
| 0.006 to 0.01             |                  | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 2       | 2       | 3       | 3        |
| 0.02 to 0.05              | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 2       | 3       | 3       | 4        |
| 0.06 to 0.1               | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 2       | 3       | 4       | 5        |
| 0.2 to 0.5                | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 3       | 4       | 5       | 6        |
| 0.6 to 1                  | 1                | 1       | 1       | 1       | 1       | 1       | 1       | 2       | 3       | 4       | 5       | 6        |
| > 1                       | 1                | 1       | 1       | 1       | 1       | 1       | 2       | 2       | 4       | 5       | 7       | 9        |

## G.9 Sulfuric Acid (H<sub>2</sub>SO<sub>4</sub>) Corrosion

### G.9.1 DESCRIPTION OF DAMAGE

Sulfuric acid (H<sub>2</sub>SO<sub>4</sub>) is one of the most widely used industrial chemicals. One common use of concentrated sulfuric acid is as a catalyst for the alkylation process. Sulfuric acid is a very strong acid that can be extremely corrosive under certain conditions. The corrosiveness of sulfuric acid varies widely, and depends on many factors. Acid concentration and temperature are the foremost factors that influence corrosion. In addition, velocity effects and presence of impurities in the acid, especially oxygen or oxidants, can have a significant impact on corrosion.

Although sulfuric acid corrodes carbon steel, it is the material typically chosen for equipment and piping handling concentrated sulfuric acid at near ambient temperatures. The corrosion rate of steel by sulfuric acid as a function of acid concentration and temperature under stagnant conditions is provided in NACE Publication 5A151 (Reference 1). Stagnant or low flow (< 3 fps) conditions typically cause general thinning of carbon steel. The ferrous sulfate corrosion prod-

uct film is somewhat protective, and as it builds on the metal surface the corrosion rate decreases. The mass transfer of ferrous sulfate away from the corroding steel surface is the rate-limiting step for the corrosion. Acid solution velocity above approximately 3 fps (turbulent flow) has a significant impact on this mass transfer rate and thus the corrosion rate. Corrosion rates for steel pipelines carrying sulfuric acid at various conditions and velocities have been calculated from a well-established mathematical model (Reference 2). The calculated rates were based on pure sulfuric acid solutions with no ferrous sulfate present in the acid solution. These rates for turbulent flow in straight pipes were then multiplied by a factor of 3 (based on experience cited in Reference 2) to account for the enhanced localized corrosion that occurs at elbows, tees, valves, and areas of internal surface roughness such as protuberances at welded joints. This provides maximum estimated corrosion rates. Actual corrosion rates could be 20 to 50% of these estimated maximum corrosion rates.

Although the performance of many alloys in sulfuric acid service is primarily related to the acid concentration and temperature, velocity and the presence of an oxidant can play a



Table G-33—Basic Data Required for Analysis of Sulfuric Acid Corrosion

| Basic Data                             | Comments                                                                                                                                                                                                                                                                                                                  |
|----------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Material of Construction               | Determine the material of construction of the equipment/piping.                                                                                                                                                                                                                                                           |
| Acid Concentration (wt %)              | Determine the concentration of the sulfuric acid present in this equipment/piping. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.                                                                                                                           |
| Maximum Temperature (°F)               | Determine the maximum temperature present in this equipment/piping. This may be the maximum process temperature, but local heating conditions such as effect of the sun or heat tracing should be considered.                                                                                                             |
| Velocity of Acid (fps)                 | Determine the maximum velocity of the acid in this equipment/piping. Although conditions in a vessel may be essentially stagnant, the acid velocity in flowing nozzles (inlet, outlet, etc.) should be considered.                                                                                                        |
| Oxygen/Oxidant Present?<br>(Yes or No) | Determine whether the acid contains oxygen or some other oxidant. If in doubt, consult a knowledgeable process engineer. This data is only necessary if the material of construction is Alloy B-2. For carbon steel and other alloys, the corrosion rates in the tables assume the acid does not contain oxygen/oxidants. |

significant role as well. This is because these alloys often depend upon formation of a protective oxide film to provide passivity, and therefore corrosion resistance. The presence of an oxidant usually improves the corrosion performance in sulfuric acid service of alloys such as stainless steel and many nickel alloys. This is not the case with Alloy B-2, which can suffer drastically high corrosion rates if an oxidant is present in the acid. The corrosion rates provided in these tables are from published literature, and the corrosion rates for non-aerated acid services are used to provide conservatism, except for Alloy B-2. This conservatism is appropriate because other acid contaminants and velocity can affect the material's passivity. The effect of velocity on corrosion rates is assumed to hold over a wide range of conditions for very little information on the effect of velocity is published.

### G.9.2 BASIC DATA

The data listed in Table G-33 are required to determine the estimated corrosion rate for sulfuric acid service. If exact process data are not known, contact a knowledgeable process engineer to obtain the best estimates.

### G.9.3 DETERMINATION OF MAXIMUM ESTIMATED CORROSION RATE

Using the basic data from Table G-33, determine the maximum estimated corrosion rate of the material of construction

from the appropriate table, Table G-34 through Table G-40. Note that the corrosion rates of Alloy B-2 can increase drastically in the presence of an oxidant (e.g., oxygen or ferric ions), which is not reflected in Table G-40. For this environment, consult a corrosion engineer for estimated corrosion rates of Alloy B-2. A flow chart of the steps required to determine the maximum estimated corrosion rate in sulfuric acid is presented in Figure G-5.

### References

1. *Materials of Construction for Handling Sulfuric Acid*, NACE Publication 5A151 (1985 Revision).
2. Sheldon W. Dean and George D. Grab, "Corrosion of Carbon Steel by Concentrated Sulfuric Acid," NACE paper #147, CORROSION/84.
3. S. K. Brubaker, *Materials of Construction for Sulfuric Acid, Process Industries Corrosion—The Theory and Practice*, NACE, Houston TX, pp. 243-258.
4. *The Corrosion Resistance of Nickel-Containing Alloys in Sulfuric Acid and Related Compounds*, Corrosion Engineering Bulletin CEB-1, The International Nickel Company, Inc. (INCO), 1983.
5. *Corrosion Resistance of Hastelloy® Alloys*, Haynes International, Inc., 1984.

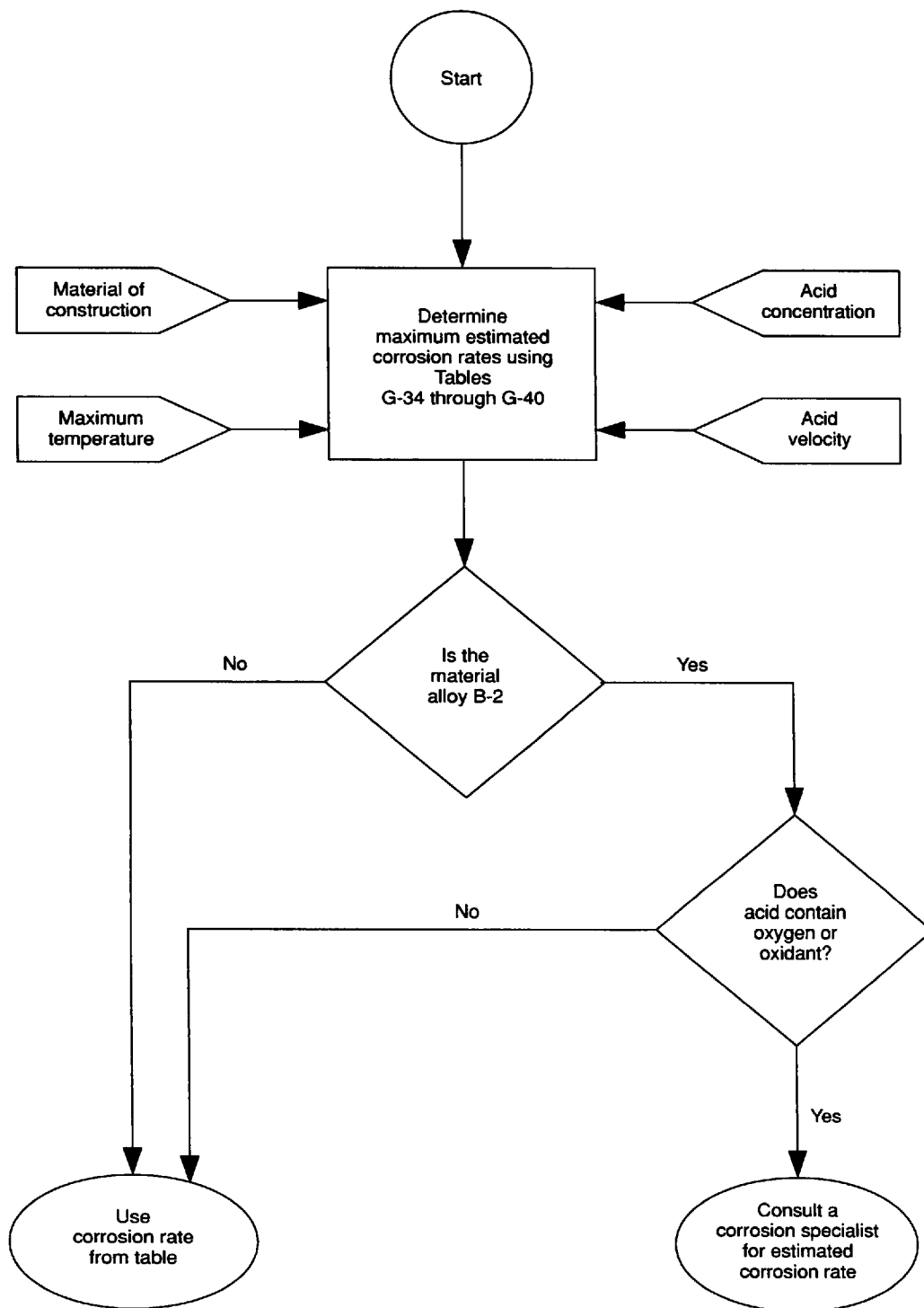


Figure G-5—Determination of Sulfuric Acid Corrosion Rates

Table G-34—Estimated Corrosion Rate for Carbon Steel (mpy)

| Acid Conc (wt%) | Acid Temp (°F) | Carbon Steel Corrosion Rate (mpy) |     |     |     |       |       |       |         |      |
|-----------------|----------------|-----------------------------------|-----|-----|-----|-------|-------|-------|---------|------|
|                 |                | Acid Velocity (fps)               |     |     |     |       |       |       |         |      |
|                 |                | 0                                 | 1   | 2   | 3   | 4 – 5 | 6 – 7 | 8 – 9 | 10 – 12 | > 12 |
| 99 – 100        | < 42           | 5                                 | 7   | 9   | 12  | 45    | 60    | 75    | 95      | 120  |
|                 | 42 – 77        | 12                                | 14  | 17  | 20  | 65    | 85    | 110   | 140     | 170  |
|                 | 78 – 104       | 50                                | 55  | 60  | 70  | 270   | 360   | 450   | 580     | 720  |
|                 | 105 – 140      | 100                               | 150 | 200 | 300 | 999   | 999   | 999   | 999     | 999  |
| 98              | < 42           | 4                                 | 6   | 8   | 10  | 35    | 45    | 60    | 75      | 90   |
|                 | 42 – 77        | 5                                 | 10  | 15  | 20  | 80    | 110   | 140   | 180     | 220  |
|                 | 78 – 104       | 15                                | 25  | 40  | 60  | 290   | 390   | 490   | 640     | 780  |
|                 | 105 – 140      | 40                                | 80  | 120 | 250 | 999   | 999   | 999   | 999     | 999  |
| 95 – 97         | < 42           | 8                                 | 10  | 12  | 15  | 60    | 80    | 110   | 130     | 160  |
|                 | 42 – 77        | 15                                | 20  | 25  | 40  | 170   | 220   | 270   | 350     | 430  |
|                 | 78 – 104       | 25                                | 40  | 60  | 100 | 500   | 650   | 820   | 999     | 999  |
|                 | 105 – 140      | 50                                | 100 | 200 | 500 | 999   | 999   | 999   | 999     | 999  |
| 93 – 94         | < 42           | 10                                | 15  | 20  | 25  | 120   | 160   | 200   | 260     | 330  |
|                 | 42 – 77        | 20                                | 25  | 40  | 70  | 340   | 450   | 570   | 740     | 910  |
|                 | 78 – 104       | 30                                | 40  | 75  | 130 | 640   | 850   | 999   | 999     | 999  |
|                 | 105 – 120      | 60                                | 120 | 250 | 600 | 999   | 999   | 999   | 999     | 999  |
| 90 – 92         | < 42           | 15                                | 25  | 45  | 70  | 320   | 430   | 540   | 710     | 870  |
|                 | 42 – 77        | 25                                | 40  | 80  | 120 | 700   | 940   | 999   | 999     | 999  |
|                 | 78 – 104       | 35                                | 60  | 100 | 200 | 940   | 999   | 999   | 999     | 999  |
|                 | 105 – 140      | 70                                | 150 | 300 | 800 | 999   | 999   | 999   | 999     | 999  |
| 86 – 89         | < 42           | 20                                | 30  | 50  | 80  | 380   | 500   | 630   | 810     | 999  |
|                 | 42 – 77        | 30                                | 160 | 300 | 420 | 690   | 920   | 999   | 999     | 999  |
|                 | 78 – 104       | 45                                | 450 | 850 | 999 | 999   | 999   | 999   | 999     | 999  |
|                 | 105 – 140      | 80                                | 999 | 999 | 999 | 999   | 999   | 999   | 999     | 999  |

Table G-35—Estimated Corrosion Rate for Carbon Steel (mpy)

| Acid Conc (wt%) | Acid Temp (°F) | Carbon Steel Corrosion Rate (mpy) |     |     |     |       |       |       |         |     |
|-----------------|----------------|-----------------------------------|-----|-----|-----|-------|-------|-------|---------|-----|
|                 |                | Acid Velocity (fps)               |     |     |     |       |       |       |         |     |
|                 |                | 0                                 | 1   | 2   | 3   | 4 – 5 | 6 – 7 | 8 – 9 | 10 – 12 | >12 |
| 81 – 85         | < 42           | 20                                | 25  | 35  | 45  | 210   | 280   | 350   | 460     | 570 |
|                 | 42 – 77        | 30                                | 50  | 100 | 150 | 680   | 910   | 999   | 999     | 999 |
|                 | 78 – 104       | 40                                | 100 | 200 | 400 | 999   | 999   | 999   | 999     | 999 |
|                 | 105 – 140      | 80                                | 200 | 400 | 999 | 999   | 999   | 999   | 999     | 999 |
| 76 – 80         | < 42           | 15                                | 20  | 20  | 25  | 110   | 150   | 190   | 250     | 300 |
|                 | 42 – 77        | 20                                | 40  | 70  | 120 | 570   | 760   | 950   | 999     | 999 |
|                 | 78 – 104       | 30                                | 60  | 120 | 250 | 999   | 999   | 999   | 999     | 999 |
|                 | 105 – 140      | 60                                | 120 | 300 | 900 | 999   | 999   | 999   | 999     | 999 |
| 70 – 75         | < 42           | 10                                | 15  | 20  | 25  | 130   | 170   | 220   | 280     | 350 |
|                 | 42 – 77        | 15                                | 30  | 50  | 100 | 490   | 650   | 810   | 999     | 999 |
|                 | 78 – 104       | 25                                | 50  | 100 | 200 | 980   | 999   | 999   | 999     | 999 |
|                 | 105 – 140      | 50                                | 100 | 250 | 800 | 999   | 999   | 999   | 999     | 999 |
| 65 – 69         | < 42           | 20                                | 30  | 40  | 60  | 280   | 370   | 460   | 690     | 740 |
|                 | 42 – 77        | 30                                | 50  | 100 | 170 | 830   | 999   | 999   | 999     | 999 |
|                 | 78 – 104       | 50                                | 100 | 180 | 300 | 999   | 999   | 999   | 999     | 999 |
|                 | 105 – 140      | 100                               | 200 | 400 | 999 | 999   | 999   | 999   | 999     | 999 |
| 60 – 64         | < 42           | 75                                | 85  | 100 | 120 | 570   | 760   | 950   | 999     | 999 |
|                 | 42 – 77        | 120                               | 170 | 250 | 400 | 999   | 999   | 999   | 999     | 999 |
|                 | 78 – 104       | 200                               | 300 | 600 | 900 | 999   | 999   | 999   | 999     | 999 |
|                 | 105 – 140      | 500                               | 750 | 999 | 999 | 999   | 999   | 999   | 999     | 999 |

Table G-36—Estimated Corrosion Rates for 304 SS (mpy)

| Acid Concentration<br>(wt%) | 304 SS Corrosion Rate (mpy) |              |            |              |              |            |              |              |            |
|-----------------------------|-----------------------------|--------------|------------|--------------|--------------|------------|--------------|--------------|------------|
|                             | ≤ 86°F                      |              |            | 87 – 122°F   |              |            | 123 – 158°F  |              |            |
|                             | 0 – 4<br>fps                | 5 – 7<br>fpa | > 7<br>fpa | 0 – 4<br>fpa | 5 – 7<br>fps | > 7<br>fps | 0 – 4<br>fps | 5 – 7<br>fps | > 7<br>fps |
| 96 – 100                    | 5                           | 10           | 15         | 20           | 40           | 60         | 200          | 400          | 600        |
| 90 – 95                     | 20                          | 40           | 60         | 40           | 80           | 120        | 500          | 999          | 999        |
| 85 – 89                     | 40                          | 80           | 120        | 80           | 160          | 240        | 999          | 999          | 999        |
| 80 – 84                     | 100                         | 200          | 300        | 500          | 999          | 999        | 999          | 999          | 999        |
| 70 – 79                     | 500                         | 999          | 999        | 999          | 999          | 999        | 999          | 999          | 999        |
| 60 – 69                     | 999                         | 999          | 999        | 999          | 999          | 999        | 999          | 999          | 999        |
| 41 – 59                     | 999                         | 999          | 999        | 999          | 999          | 999        | 999          | 999          | 999        |
| 21 – 40                     | 999                         | 999          | 999        | 999          | 999          | 999        | 999          | 999          | 999        |
| 11 – 20                     | 400                         | 800          | 999        | 999          | 999          | 999        | 999          | 999          | 999        |
| 6 – 10                      | 200                         | 400          | 600        | 800          | 999          | 999        | 999          | 999          | 999        |
| 2 – 5                       | 50                          | 100          | 150        | 200          | 400          | 600        | 500          | 999          | 999        |
| < 2                         | 20                          | 40           | 60         | 70           | 140          | 210        | 200          | 400          | 600        |

Table G-37—Estimated Corrosion Rates for 316 SS (mpy)

| Acid Concentration<br>(wt%) | 316 SS Corrosion Rate (mpy) |              |            |              |              |            |              |              |            |
|-----------------------------|-----------------------------|--------------|------------|--------------|--------------|------------|--------------|--------------|------------|
|                             | < 86°F                      |              |            | 87 – 122°F   |              |            | 123 – 158°F  |              |            |
|                             | 0 – 4<br>fps                | 5 – 7<br>fps | > 7<br>fps | 0 – 4<br>fps | 5 – 7<br>fps | > 7<br>fps | 0 – 4<br>fps | 5 – 7<br>fps | > 7<br>fps |
| 96 – 100                    | 5                           | 10           | 15         | 15           | 30           | 45         | 100          | 200          | 300        |
| 90 – 95                     | 10                          | 20           | 30         | 30           | 60           | 90         | 400          | 800          | 999        |
| 85 – 89                     | 20                          | 40           | 60         | 50           | 100          | 50         | 800          | 999          | 999        |
| 80 – 84                     | 50                          | 100          | 150        | 400          | 800          | 999        | 999          | 999          | 999        |
| 70 – 79                     | 300                         | 600          | 900        | 999          | 999          | 999        | 999          | 999          | 999        |
| 60 – 69                     | 600                         | 999          | 999        | 999          | 999          | 999        | 999          | 999          | 999        |
| 41 – 59                     | 900                         | 999          | 999        | 999          | 999          | 999        | 999          | 999          | 999        |
| 21 – 40                     | 200                         | 400          | 600        | 999          | 999          | 999        | 999          | 999          | 999        |
| 11 – 20                     | 30                          | 60           | 90         | 60           | 120          | 180        | 200          | 400          | 600        |
| 6 – 10                      | 10                          | 20           | 30         | 30           | 60           | 90         | 80           | 160          | 240        |
| 2 – 5                       | 5                           | 10           | 15         | 20           | 40           | 60         | 40           | 80           | 120        |
| < 2                         | 5                           | 10           | 15         | 5            | 10           | 15         | 10           | 20           | 30         |

Table G-38—Estimated Corrosion Rates for Alloy 20 (mpy)

| Acid Conc<br>(wt%) | Alloy 20 Corrosion Rate (mpy) |               |             |              |               |             |              |               |             |              |               |             |
|--------------------|-------------------------------|---------------|-------------|--------------|---------------|-------------|--------------|---------------|-------------|--------------|---------------|-------------|
|                    | ≤ 100°F                       |               |             | 101 – 150°F  |               |             | 151 – 176°F  |               |             | 177 – 214°F  |               |             |
|                    | 0 – 6<br>fps                  | 7 – 10<br>fps | > 10<br>fps | 0 – 6<br>fps | 7 – 10<br>fps | > 10<br>fps | 0 – 6<br>fps | 7 – 10<br>fps | > 10<br>fps | 0 – 6<br>fps | 7 – 10<br>fps | > 10<br>fps |
| 96 – 100           | 2                             | 4             | 6           | 5            | 10            | 15          | 15           | 30            | 45          | 40           | 80            | 120         |
| 90 – 95            | 3                             | 6             | 9           | 10           | 20            | 30          | 25           | 50            | 75          | 50           | 100           | 150         |
| 80 – 89            | 3                             | 6             | 9           | 10           | 20            | 30          | 30           | 60            | 90          | 60           | 120           | 180         |
| 61 – 79            | 3                             | 6             | 9           | 15           | 30            | 45          | 50           | 100           | 150         | 100          | 200           | 300         |
| 51 – 60            | 3                             | 6             | 9           | 10           | 20            | 30          | 30           | 60            | 90          | 60           | 120           | 180         |
| 41 – 50            | 3                             | 6             | 9           | 10           | 20            | 30          | 30           | 60            | 90          | 50           | 100           | 150         |
| 31 – 40            | 3                             | 6             | 9           | 10           | 20            | 30          | 25           | 50            | 75          | 40           | 80            | 120         |
| 21 – 30            | 2                             | 4             | 6           | 5            | 10            | 15          | 20           | 40            | 60          | 40           | 80            | 120         |
| 11 – 20            | 2                             | 4             | 6           | 5            | 10            | 15          | 20           | 40            | 60          | 35           | 70            | 105         |
| 6 – 10             | 2                             | 4             | 6           | 3            | 6             | 9           | 5            | 10            | 15          | 25           | 50            | 75          |
| ≤ 5                | 2                             | 4             | 6           | 3            | 6             | 9           | 3            | 6             | 9           | 20           | 40            | 60          |

Table G-39—Estimated Corrosion Rates for Alloy C-276 (mpy)

| Acid Conc<br>(wt%) | Alloy B-2 Corrosion Rate (mpy) |             |             |             |             |             |             |             |             |             |             |             |
|--------------------|--------------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
|                    | ≤ 125°F                        |             |             | 126 – 150°F |             |             | 151 – 175°F |             |             | 176 – 200°F |             |             |
|                    | 0–6<br>fps                     | 7–10<br>fps | > 10<br>fps | 0–6<br>fps  | 7–10<br>fps | > 10<br>fps | 0–6<br>fps  | 7–10<br>fps | > 10<br>fps | 0–6<br>fps  | 7–10<br>fps | > 10<br>fps |
| 96–100             | 3                              | 6           | 9           | 4           | 8           | 12          | 5           | 10          | 15          | 20          | 40          | 60          |
| 90–95              | 4                              | 8           | 12          | 5           | 10          | 15          | 20          | 40          | 60          | 50          | 100         | 150         |
| 81–89              | 5                              | 10          | 15          | 10          | 20          | 30          | 20          | 40          | 60          | 60          | 120         | 180         |
| 71–80              | 5                              | 10          | 15          | 10          | 20          | 30          | 20          | 40          | 60          | 50          | 100         | 150         |
| 41–70              | 5                              | 10          | 15          | 10          | 20          | 30          | 15          | 30          | 45          | 40          | 80          | 120         |
| 11–40              | 4                              | 8           | 12          | 5           | 10          | 15          | 15          | 30          | 45          | 40          | 80          | 120         |
| 6–10               | 4                              | 8           | 12          | 5           | 10          | 15          | 10          | 20          | 30          | 30          | 60          | 90          |
| ≤ 5                | 3                              | 6           | 9           | 4           | 8           | 12          | 5           | 10          | 15          | 15          | 30          | 45          |

Table G-40—Estimated Corrosion Rates for Alloy B-2<sup>a</sup>

| Acid Conc<br>(wt%) | Alloy B-2 Corrosion Rate (mpy) |             |             |             |             |             |             |             |             |             |             |             |
|--------------------|--------------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
|                    | ≤ 125°F                        |             |             | 126 – 150°F |             |             | 151 – 175°F |             |             | 176 – 200°F |             |             |
|                    | 0–6<br>fps                     | 7–10<br>fps | > 10<br>fps | 0–6<br>fps  | 7–10<br>fps | > 10<br>fps | 0–6<br>fps  | 7–10<br>fps | > 10<br>fps | 0–6<br>fps  | 7–10<br>fps | > 10<br>fps |
| 50–100             | 2                              | 4           | 6           | 3           | 6           | 9           | 4           | 8           | 12          | 5           | 10          | 15          |
| 40–49              | 3                              | 6           | 9           | 4           | 8           | 12          | 4           | 8           | 12          | 5           | 10          | 15          |
| 26–39              | 4                              | 8           | 12          | 5           | 10          | 15          | 5           | 10          | 15          | 5           | 10          | 15          |
| ≤ 25               | 5                              | 10          | 15          | 10          | 20          | 30          | 10          | 20          | 30          | 10          | 20          | 30          |

<sup>a</sup>Oxidants present (even in a few ppm) accelerate corrosion rates and pitting. Alloy B-2 should not be used in oxidizing conditions.

## G.10 Hydrofluoric Acid (HF) Corrosion

### G.10.1 DESCRIPTION OF DAMAGE

Concentrated hydrofluoric acid (HF) is used as the acid catalyst in HF alkylation units. The alkylation reaction chemically combines an alkane (usually isobutane) with an olefin (butylene, propylene, amylene) in the presence of the acid catalyst. HF presents severe health hazards as both a liquid and vapor. If spilled, HF may form a dense, low lying, toxic cloud. Extreme caution should be exercised when using HF.

Corrosion of materials in HF primarily depends on the HF-in-water concentration and the temperature. Other variables, such as velocity, turbulence, aeration, impurities, etc., can strongly influence corrosion. Some metals will form a protective fluoride film or scale which protects the surface. Loss of this protective film, especially through high velocity or turbulence, will likely result in greatly accelerated corrosion rates.

Corrosion in 80% and stronger HF-in-water solutions is equivalent to corrosion in anhydrous hydrofluoric acid (AHF, < 200 ppm H<sub>2</sub>O). Below 80% HF, the acid is considered aqueous and metal corrosion is highly temperature and velocity dependent and usually very accelerated.

The usual HF-in-water concentrations at typical HF alkylation units are 96%–99+% and the temperatures are generally below 150°F. Under these conditions carbon steel is widely used for all equipment except where close tolerances are required for operation (i.e., pumps, valves, instruments).

Where close tolerances are required and at temperatures over 150°F to approximately 300°F, Alloy 400 is typically used.

Accelerated corrosion from water dilution of the acid is often encountered in low points (bleeders, line pockets, etc.) if unit dryout leaves residual free water in these areas.

### G.10.2 BASIC DATA

Table G-41 lists the basic data required for estimating corrosion rates for steel and Alloy 400 in HF solutions. The table also provides comments regarding the data that is required.

### G.10.3 DETERMINATION OF ESTIMATED CORROSION RATES

If HF is present in any concentration, then the equipment/piping is considered to be susceptible to HF corrosion. The basic data from Table G-41 should be used to obtain the estimated corrosion rate from Table G-42 for carbon steel or Table G-43 for Alloy 400. A flow chart of the steps required to determine the applicable corrosion rates is given in Figure G-6.

It is important to note that the corrosion rate is very high in the initial stages of exposure to HF as the protective fluoride scale is being established. Once established, the fluoride scale protects the steel resulting in low corrosion rates unless the scale is disturbed or removed.

Alloy steels have been found to exhibit higher corrosion rates than mild carbon steel in both dilute and concentrated

Table G-41—Basic Data Required for Analysis of Hydrofluoric Acid Corrosion

| Basic Data                               | Comments                                                                                                                                                                                                                                                                                                                                      |
|------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| HF-in-water concentration (wt%)          | Determine the concentration of HF in the water.                                                                                                                                                                                                                                                                                               |
| Material of Construction                 | Determine the material used to fabricate the equipment/piping.                                                                                                                                                                                                                                                                                |
| Maximum Service Temperature (°F)         | Determine the maximum temperature of the process stream.                                                                                                                                                                                                                                                                                      |
| Velocity (ft/sec)                        | Determine the velocity range of the process stream                                                                                                                                                                                                                                                                                            |
| Oxygen/Oxidizers present?<br>(Yes or No) | Oxidizers can greatly accelerate corrosion of Alloy 400. No definition in terms of concentration of dissolved oxygen in the acid can be given. Acid in shipment and transfer will usually be completely air-free and air is typically present only after opening of equipment for inspection, leaks, or improperly prepared feed to the unit. |

Table G-42—Estimated Corrosion Rates (mpy) for Carbon Steel

| Temp<br>(°F) | Velocity<br>(fps) | HF-in-Water Concentration |        |         |          |              |               |
|--------------|-------------------|---------------------------|--------|---------|----------|--------------|---------------|
|              |                   | 0 – 1%                    | 2 – 5% | 6 – 63% | 64 – 80% | > 80%        |               |
|              |                   |                           |        |         |          | Low Residual | High Residual |
| < 80         | < 10              | 2                         | 150    | 800     | 5        | 2            | 6             |
|              | ≥ 10              | 20                        | 999    | 999     | 50       | 20           | 60            |
| ≥80 – 130    | < 10              | 10                        | 500    | 999     | 30       | 5            | 15            |
|              | ≥ 10              | 200                       | 999    | 999     | 300      | 50           | 150           |
| ≥130 – 150   | < 10              | 10                        | 500    | 999     | 30       | 10           | 30            |
|              | ≥ 10              | 100                       | 999    | 999     | 300      | 100          | 300           |
| ≥151 – 160   | < 10              | 100                       | 999    | 999     | 500      | 20           | 60            |
|              | ≥ 10              | 999                       | 999    | 999     | 999      | 200          | 600           |
| ≥161 – 175   | < 10              | 100                       | 999    | 999     | 500      | 50           | 150           |
|              | ≥ 10              | 999                       | 999    | 999     | 999      | 500          | 999           |
| ≥ 176 – 200  | < 10              | 100                       | 999    | 999     | 500      | 70           | 210           |
|              | ≥ 10              | 999                       | 999    | 999     | 999      | 700          | 999           |
| > 200        | < 10              | 500                       | 999    | 999     | 999      | 100          | 300           |
|              | ≥ 10              | 999                       | 999    | 999     | 999      | 999          | 999           |

Table G-43—Estimated Corrosion Rates (mpy) for Alloy 400

| Temp<br>(°F) | Aerated? | HF-in-Water Concentration |        |         |          |       |
|--------------|----------|---------------------------|--------|---------|----------|-------|
|              |          | 0 – 1%                    | 2 – 5% | 6 – 63% | 64 – 80% | > 80% |
| < 80         | No       | 1                         | 1      | 10      | 1        | 2     |
|              | Yes      | 10                        | 10     | 25      | 10       | 15    |
| 80 – 150     | No       | 1                         | 1      | 15      | 5        | 3     |
|              | Yes      | 10                        | 10     | 30      | 20       | 15    |
| 151 – 200    | No       | 5                         | 5      | 20      | 10       | 5     |
|              | Yes      | 20                        | 20     | 100     | 50       | 20    |
| > 200        | No       | 10                        | 10     | 20      | 20       | 10    |
|              | Yes      | 100                       | 100    | 200     | 200      | 100   |

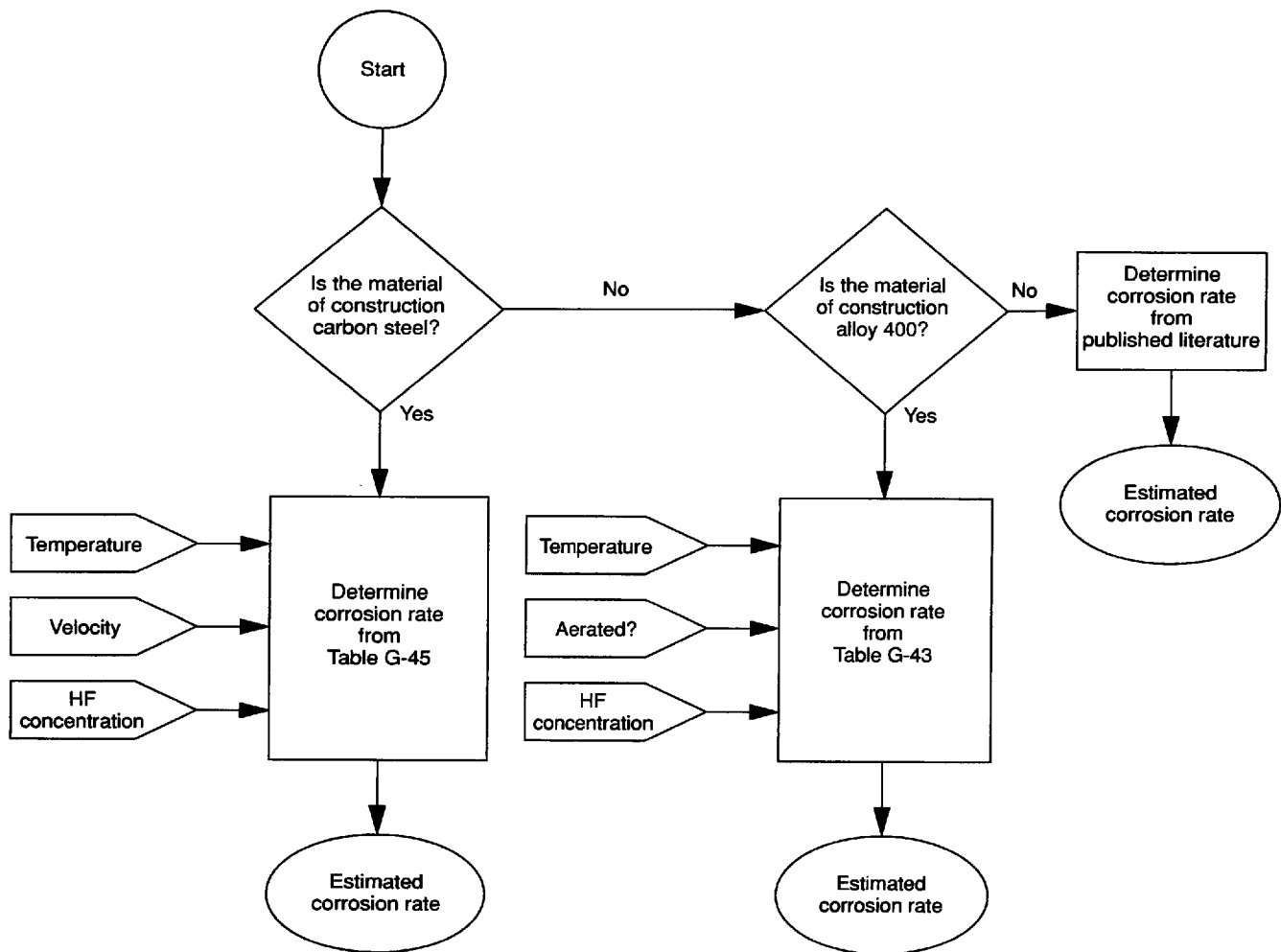


Figure G-6—Determination of HF Corrosion Rates

HF and generally are not specified for this service. Higher alloys are sometimes used in HF service and corrosion rates, if unknown, should be obtained from published literature or from the manufacturer (Reference 4). It is important to consider the galvanic effects of welding carbon steel to Alloy 400 or other corrosion resistant alloys. Accelerated and localized attack of the carbon steel may result from galvanic coupling. Increased rates of corrosion have also been reported in carbon steels which contain high levels of residual elements, notably Cu, Ni, and Cr (Reference 6).

Corrosion caused by HF results in general thinning except in the event of potential galvanic attack. The presence of HF may also result in hydrogen stress cracking and blistering. These degradation modes are considered in the Stress Corrosion Cracking Technical Module.

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2. *Materials for Receiving, Handling and Storing Hydrofluoric Acid*, NACE Publication 5A171 (1995 Revision).
3. *Corrosion Resistance of Nickel-Containing Alloys in Hydrofluoric Acid, Hydrogen Fluoride and Fluorine*, Corrosion Engineering, Bulletin CEB-5, The International Nickel Co., Inc., 1968.
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5. J. Dobis, D. Clarida and J. Richert, "A Survey of Plant Practices and Experience in HF Alkylation Units," NACE Paper 511, Corrosion/94.
6. H. Hashim and W. Valerioti, "Effect of Residual Copper, Nickel, and Chromium on the Corrosion Resistance of Carbon Steel in Hydrofluoric Acid Alkylation Service," NACE Paper 623, Corrosion/93.

## G.11 Sour Water Corrosion

### G.11.1 DESCRIPTION OF DAMAGE

Sour water corrosion is broadly defined as corrosion by water containing hydrogen sulfide and ammonia, and it is typically a concern for carbon steel above neutral pH. This corrosion is caused by aqueous ammonium bisulfide ( $\text{NH}_4\text{HS}$ ) which is also known as ammonium hydrosulfide. The primary variables which influence sour water corrosion rates are the  $\text{NH}_4\text{HS}$  concentration of the water and the stream velocity. Secondary variables are the pH, cyanide, and oxygen contents of the water.

Sour water corrosion is of concern across a broad range of the most common refining process units, notably hydrotreating, hydrocracking, coking, catalytic cracking, light ends, amine treating and sour water stripping. Hydrogen sulfide is typically formed by thermal or catalytic conversion of sulfur compounds. Ammonia is similarly formed from nitrogen compounds. To some extent, sour water corrosion can be of importance in crude distillation depending on water pH. Below neutral pH, HCl is generally the controlling corrosion mechanism in crude distillation, naphtha hydrotreating, and catalytic reforming water condensates. Small amounts of ammonia may also be formed in some distillate hydrotreaters, depending on operating conditions.

### G.11.2 BASIC DATA

The data listed in Table G-44 are required to estimate the sour water corrosion rate. Figure G-7 illustrates the steps

required to determine the corrosion rate. If precise data have not been measured, a knowledgeable process specialist should be consulted.

### G.11.3 DETERMINATION OF SOUR WATER CORROSION RATE

Table G-45 should be used to estimate corrosion rates in sour water. An outline of steps used to estimate the corrosion rate is provided in Figure G-7.

#### References

1. R. L. Piehl, "Survey of Corrosion in Hydrocracker Effluent Air Coolers," *Materials Protection*, January, 1976.
2. E. F. Ehmke, "Corrosion Correlation with Ammonia and Hydrogen Sulfide in Air Coolers," *Materials Protection*, July, 1975.
3. D. G. Damin and J. D. McCoy, "Prevention of Corrosion in Hydrodesulfurizer Air Coolers and Condensers," *Materials Performance*, December, 1978, pp. 23-26 (See also NACE Corrosion/78 paper #131).
4. C. Scherrer, M. Durrieu, and G. Jarno, "Distillate and Resid Hydroprocessing: Coping with High Concentrations of Ammonium Bisulfide in the Process Water," *Materials Performance*, November, 1980, pp 25-31 (See also NACE Corrosion/79 paper #27).

Table G-44—Basic Data Required for Analysis of Sour Water Corrosion

| Basic Data             | Comments                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
|------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| $\text{NH}_4\text{HS}$ | Determine the $\text{NH}_4\text{HS}$ concentration of the condensed water. It may be calculated from analyses of $\text{H}_2\text{S}$ and $\text{NH}_3$ as follows:<br><br>If $\text{wt } \% \text{H}_2\text{S} < 2 \times (\text{wt } \% \text{NH}_3)$ , $\text{wt } \% \text{NH}_4\text{HS} = 1.5 \times (\text{wt } \% \text{H}_2\text{S})$<br><br>If $\text{wt } \% \text{H}_2\text{S} > 2 \times (\text{wt } \% \text{NH}_3)$ , $\text{wt } \% \text{NH}_4\text{HS} = 3 \times (\text{wt } \% \text{NH}_3)$ |
| OR                     |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| $K_p$ factor           | $K_p$ may be used where sour water analyses have not been conducted and is based on the vapor phase $\text{H}_2\text{S}$ and $\text{NH}_3$ :<br>$K_p = \text{mole } \% \text{H}_2\text{S} \times \text{mole } \% \text{NH}_3$ (on dry basis)                                                                                                                                                                                                                                                                     |
| Stream Velocity (ft/s) | The vapor phase velocity should be used in a two-phase system. The liquid phase velocity should be used in a liquid full system.                                                                                                                                                                                                                                                                                                                                                                                 |



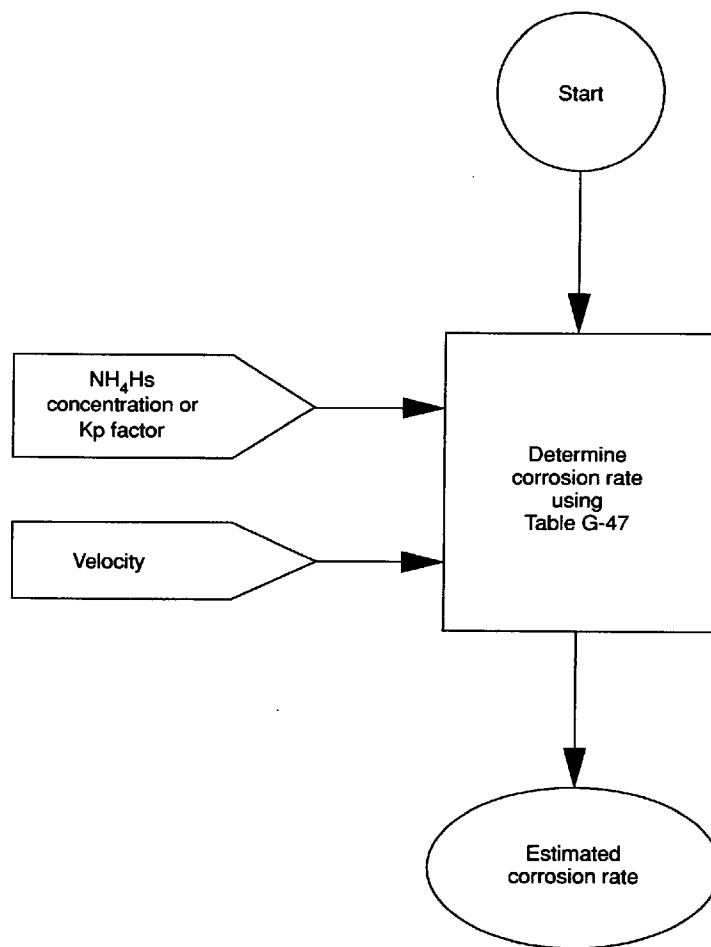


Figure G-7—Determination of Sour Water Corrosion Rates

Table G-45—Estimated Corrosion Rates for Carbon Steel (mpy)

| K <sub>p</sub> | NH <sub>4</sub> HS<br>(wt %) | Velocity (fps) |         |         |     |
|----------------|------------------------------|----------------|---------|---------|-----|
|                |                              | < 10           | 10 – 20 | 21 – 30 | >30 |
| < 0.07         | < 2                          | 5              | 8       | 10      | 15  |
| 0.07 – 0.4     | 2 – 8                        | 15             | 25      | 50      | 150 |
| 0.41 – 1.0     | 8 – 20                       | 30             | 50      | 300     | 500 |
| > 1.0          | >20                          | 300            | 500     | 800     | 999 |

## G.12 Amine Corrosion

### G.12.1 DESCRIPTION OF DAMAGE

Amine corrosion is a form of often-localized corrosion which occurs principally on carbon steel in some gas treating processes. Carbon steel is also vulnerable to stress corrosion cracking in gas treating amines if it is not postweld heat treated (see H.6). Gas treating amines fall into two major categories—chemical solvents and physical solvents. This supplement deals with corrosion in the most common chemical solvents, monoethanolamine (MEA), diethanolamine (DEA), and methyldiethanolamine (MDEA). These amines are used to remove acid gases, primarily  $H_2S$ , from plant streams. MEA and DEA will also remove  $CO_2$ , but MDEA is selective to  $H_2S$  and will remove little  $CO_2$  if it is present. Generally, corrosion in MDEA is less than in MEA and DEA when contaminants are well controlled.

Carbon steel corrosion in amine treating processes is a function of a number of inter-related factors, the primary ones being the concentration of the amine solution, the acid gas content of the solution ("loading"), and the temperature. The most commonly used amine concentrations are 20 wt% MEA, 30 wt% DEA, and 40 to 50 wt% MDEA. At greater concentrations, corrosion rates increase.

Acid gas loading is reported in terms of moles of acid gas per mole of active amine. "Rich" solution is amine of higher acid gas loading and "lean" solution has lower acid gas loading (typically  $< 0.1$  mole/mole). Corrosion in poorly regenerated amine with high lean loadings is not an uncommon problem, particularly because lean solution temperatures are often greater than rich solution temperatures. Both  $H_2S$  and  $CO_2$  must be measured to determine the acid gas loading. In addition, only the amount of available or "active" amine should be considered when calculating the loading. In  $H_2S$  only systems, rich amine loadings up to 0.7 mole/mole have been satisfactory. In  $H_2S + CO_2$  systems, rich loading is often limited to 0.35 to 0.45 mole/mole. In MDEA units, and particularly those used for selective  $H_2S$  removal in sulfur plant tail gas cleanup, rich loadings are often below these levels. As with most corrosion mechanisms, higher temperature increases the corrosion rate.

Another important factor in amine corrosion is the presence of amine degradation products, usually referred to as "Heat Stable Amine Salts" or HSAS. These amine degradation products act in two ways. On the one hand, they reduce the amount of active amine available to absorb acid gas, resulting in higher acid gas loadings. In addition, some amine degradation products themselves are corrosive. In MEA and DEA systems, heat stable amine salts above 0.5 wt% can begin to increase corrosion although a common operating limit is 2 wt%. Corrosion can be particularly significant, even at low acid gas loadings, at  $> 2.0$  wt% HSAS. MDEA will

also form heat stable amine salts, but the primary influence on corrosion in these units is organic acid contaminants (formate, oxalate, and acetate). Thermal reclaimers are often provided in MEA units to reduce HSAS, but DEA and MDEA salts are more stable and can not be thermally reclaimed. DEA degrades less readily than MEA and MDEA.

Velocity or turbulence also influences amine corrosion. In the absence of high velocities and turbulence, amine corrosion can be fairly uniform. Higher velocities and turbulence can cause acid gas to evolve from solution, particularly at elbows and where pressure drops occur such as valves, resulting in more localized corrosion. Higher velocity and turbulence may also disrupt protective iron sulfide films that may form. Where velocity is a factor, corrosion may appear either as pitting or grooving. For carbon steel, common velocity limits are about 5 fps for rich amine and about 20 fps for lean amine.

Austenitic stainless steels are commonly used in areas which are corrosive to carbon steel with good success unless temperatures, amine concentration and degradation product levels are particularly high. Common applications for stainless steels are reboiler, reclaimers, and hot rich-lean exchanger tubes as well as pressure let-down valves and downstream piping/equipment. 12% Cr steels have been used for scrubber (absorber) tower internals successfully. Copper alloys are subject to accelerated corrosion and stress corrosion cracking and are normally avoided.

### G.12.2 BASIC DATA

The data listed in Table G-46 are required to estimate the rate of corrosion in amine service. Figure G-8 illustrates the steps required to determine the corrosion rate. If precise data has not been measured, a knowledgeable process specialist should be consulted.

### G.12.3 DETERMINATION OF AMINE CORROSION RATE

The estimated corrosion rate for carbon steel should be obtained from Table G-47 for  $\leq 20$  wt.% MEA and  $\leq 30$ wt.% DEA and from Table G-48 for  $\leq 50\%$  MDEA. If higher amine concentrations are used, the corrosion rate obtained should be multiplied by the appropriate factor from Table G-49.

To estimate the amine corrosion rate for stainless steels, select the appropriate value from Table G-50. Note that at extreme conditions of amine concentrations, temperatures, and levels of degradation products, the corrosion rate of stainless steel can be as much as 200 times the value in the Table G-50.

For corrosion rates at higher amine strengths, multiply corrosion rates in Tables G-47 and G-48 by the factors below.

Table G-46—Basic Data Required for Analysis of Amine Corrosion

| Basic Data                                         | Comments                                                                                                                                                                                                                 |
|----------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Material of Construction (CS or SS)                | Determine the material of construction of equipment/piping.                                                                                                                                                              |
| Amine Concentration (wt%)                          | Determine the amine concentration in the equipment/piping. Due to vaporization of water, a local increase in amine concentration may need to be considered in evaluating the corrosion of some reboilers and reclaimers. |
| Maximum Process Temperature (°F)                   | Determine the maximum process temperature. In reboilers and reclaimers, tube metal temperatures may be higher than the bulk process temperature.                                                                         |
| Acid Gas Loading (mole acid gas/mole active amine) | Determine the acid gas loading in the amine. If analytical results are not available, it should be estimated by a knowledgeable process engineer.                                                                        |
| Velocity (fps)                                     | Determine the maximum velocity of the amine in this equipment/piping.                                                                                                                                                    |
| Heat Stable Amine Salt (HSAS) Concentration:       |                                                                                                                                                                                                                          |
| MEA and DEA (≤ 2 wt%, 2–4 wt%, > 4 wt%)            | In MEA and DEA, “HSAS” represents the normal family of amine degradation products.                                                                                                                                       |
| MDEA (< 500, 500–4000, > 4000, wppm)               | In MDEA “HSAS” refers to organic acid contaminants, mainly formate, oxalate, and acetate.                                                                                                                                |

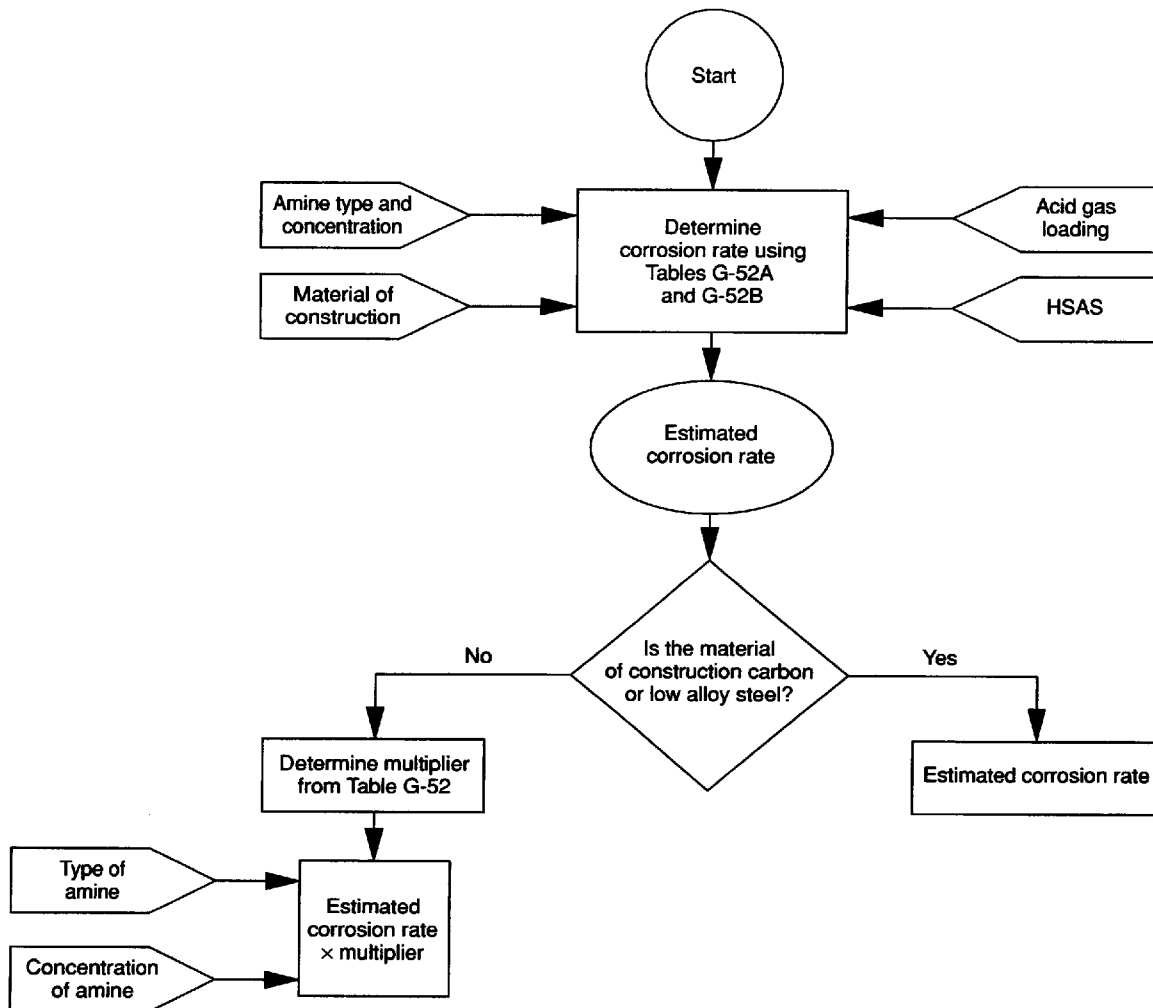


Figure G-8—Determination of Amine Corrosion Rates

Table G-47—Corrosion rate of Carbon Steel in MEA ( $\leq 20$  wt%) and DEA ( $\leq 30$  wt %)

| Acid<br><br>Gas      |               | Corrosion Rate (mpy) |      |           |      |           |      |           |      |           |      |       |      |
|----------------------|---------------|----------------------|------|-----------|------|-----------|------|-----------|------|-----------|------|-------|------|
|                      |               | Temperature (°F)     |      |           |      |           |      |           |      |           |      |       |      |
|                      |               | < 190                |      | 190 – 210 |      | 211 – 230 |      | 231 – 250 |      | 251 – 270 |      | > 270 |      |
| Loading<br>(mol/mol) | HSAS<br>(wt%) | Velocity (ft/sec)    |      |           |      |           |      |           |      |           |      |       |      |
|                      |               | ≤ 20                 | > 20 | ≤ 20      | > 20 | ≤ 20      | > 20 | ≤ 20      | > 20 | ≤ 20      | > 20 | ≤ 20  | > 20 |
| < 0.1                | ≤ 2           | 1                    | 3    | 2         | 6    | 5         | 15   | 10        | 30   | 15        | 45   | 20    | 60   |
|                      | 2.1 – 4.0     | 2                    | 6    | 2         | 6    | 6         | 20   | 15        | 40   | 20        | 45   | 30    | 80   |
|                      | > 4.0         | 5                    | 10   | 5         | 15   | 15        | 40   | 30        | 60   | 40        | 90   | 60    | 120  |
|                      |               | Velocity (ft/sec)    |      |           |      |           |      |           |      |           |      |       |      |
|                      |               | ≤ 5                  | > 5  | ≤ 5       | > 5  | ≤ 5       | > 5  | ≤ 5       | > 5  | ≤ 5       | > 5  | ≤ 5   | > 5  |
| 0.1 – 0.2            | ≤ 2           | 1                    | 3    | 2         | 6    | 5         | 15   | 10        | 30   | 15        | 45   | 20    | 60   |
|                      | 2.1 – 4.0     | 2                    | 6    | 4         | 12   | 10        | 30   | 20        | 60   | 30        | 90   | 40    | 80   |
|                      | > 4.0         | 5                    | 15   | 8         | 25   | 20        | 60   | 40        | 80   | 60        | 120  | 120   | 150  |
| 0.21 – 0.3           | ≤ 2           | 2                    | 6    | 3         | 9    | 7         | 20   | 10        | 30   | 20        | 60   | 25    | 75   |
|                      | 2.1 – 4.0     | 4                    | 10   | 6         | 20   | 15        | 40   | 20        | 50   | 40        | 80   | 50    | 100  |
|                      | > 4.0         | 8                    | 25   | 15        | 45   | 30        | 60   | 40        | 80   | 80        | 120  | 100   | 150  |
| 0.31 – 0.4           | ≤ 2           | 2                    | 6    | 4         | 10   | 7         | 20   | 15        | 40   | 25        | 70   | 30    | 80   |
|                      | 2.1 – 4.0     | 4                    | 10   | 8         | 25   | 15        | 45   | 30        | 60   | 50        | 100  | 100   | 150  |
|                      | > 4.0         | 8                    | 25   | 15        | 40   | 35        | 70   | 60        | 100  | 100       | 140  | 150   | 180  |
| 0.41 – 0.5           | ≤ 2           | 3                    | 9    | 5         | 15   | 10        | 30   | 15        | 45   | 35        | 70   | 45    | 100  |
|                      | 2.1 – 4.0     | 6                    | 15   | 10        | 30   | 20        | 60   | 45        | 90   | 70        | 130  | 90    | 150  |
|                      | > 4.0         | 10                   | 30   | 20        | 40   | 40        | 80   | 90        | 120  | 120       | 150  | 150   | 180  |
| 0.51 – 0.6           | ≤ 2           | 3                    | 9    | 7         | 20   | 10        | 30   | 25        | 75   | 40        | 100  | 50    | 120  |
|                      | 2.1 – 4.0     | 6                    | 20   | 15        | 45   | 20        | 60   | 50        | 100  | 80        | 140  | 100   | 150  |
|                      | > 4.0         | 10                   | 30   | 30        | 60   | 45        | 90   | 100       | 150  | 140       | 180  | 160   | 200  |
| 0.61 – 0.7           | ≤ 2           | 4                    | 10   | 9         | 30   | 15        | 40   | 30        | 100  | 50        | 120  | 60    | 150  |
|                      | 2.1 – 4.0     | 8                    | 15   | 20        | 40   | 30        | 60   | 60        | 100  | 90        | 140  | 100   | 150  |
|                      | > 4.0         | 15                   | 35   | 40        | 80   | 60        | 100  | 100       | 150  | 140       | 180  | 160   | 200  |
| > 0.7                | ≤ 2           | 5                    | 15   | 10        | 30   | 20        | 60   | 40        | 100  | 60        | 120  | 70    | 150  |
|                      | 2.1 – 4.0     | 10                   | 30   | 20        | 60   | 40        | 80   | 70        | 120  | 100       | 150  | 120   | 150  |
|                      | > 4.0         | 20                   | 45   | 40        | 80   | 60        | 100  | 100       | 150  | 150       | 180  | 170   | 220  |

Table G-48—Corrosion Rate of Carbon Steel in MDEA ( $\leq 50$  wt%)

| Acid<br>Gas<br>Loading<br>(mol/mol) | HSAS<br>(wt%) | Corrosion Rate (mpy)        |      |           |      |           |     |           |      |           |      |           |      |
|-------------------------------------|---------------|-----------------------------|------|-----------|------|-----------|-----|-----------|------|-----------|------|-----------|------|
|                                     |               | Temperature ( $^{\circ}$ F) |      |           |      |           |     |           |      |           |      |           |      |
|                                     |               | Velocity (ft/sec)           |      |           |      |           |     |           |      |           |      |           |      |
|                                     |               |                             |      |           |      |           |     |           |      |           |      |           |      |
|                                     |               | < 190                       |      | 190 – 210 |      | 211 – 230 |     | 231 – 250 |      | 251 – 270 |      | > 270     |      |
|                                     |               | $\leq 20$                   | > 20 | $\leq 20$ | > 20 | $\leq 2$  | > 2 | $\leq 20$ | > 20 | $\leq 20$ | > 20 | $\leq 20$ | > 20 |
| < 0.1                               | $\leq 0.5$    | 1                           | 3    | 1         | 3    | 3         | 10  | 5         | 15   | 10        | 25   | 15        | 40   |
|                                     | 0.51 – 4.0    | 2                           | 6    | 2         | 6    | 6         | 20  | 15        | 40   | 20        | 45   | 30        | 80   |
|                                     | > 4.0         | 5                           | 10   | 5         | 15   | 15        | 40  | 30        | 60   | 40        | 90   | 60        | 120  |
|                                     |               | Velocity (ft/sec)           |      |           |      |           |     |           |      |           |      |           |      |
|                                     |               | $\leq 5$                    | > 5  | $\leq 5$  | > 5  | $\leq 5$  | > 5 | $\leq 5$  | > 5  | $\leq 5$  | > 5  | $\leq 5$  | > 5  |
| 0.1 – 0.2                           | $\leq 0.5$    | 1                           | 3    | 2         | 6    | 5         | 15  | 10        | 30   | 15        | 45   | 20        | 60   |
|                                     | 0.51 – 4.0    | 2                           | 6    | 4         | 12   | 10        | 30  | 20        | 60   | 30        | 90   | 40        | 80   |
|                                     | > 4.0         | 5                           | 15   | 8         | 25   | 20        | 60  | 40        | 80   | 60        | 120  | 120       | 150  |
| 0.21 – 0.3                          | $\leq 0.5$    | 2                           | 6    | 3         | 9    | 7         | 20  | 10        | 30   | 20        | 60   | 25        | 75   |
|                                     | 0.51 – 4.0    | 4                           | 10   | 6         | 20   | 15        | 40  | 20        | 50   | 40        | 80   | 50        | 100  |
|                                     | > 4.0         | 8                           | 25   | 15        | 45   | 30        | 60  | 40        | 80   | 80        | 120  | 100       | 150  |
| 0.31 – 0.4                          | $\leq 0.5$    | 2                           | 6    | 4         | 10   | 7         | 20  | 15        | 40   | 25        | 70   | 30        | 80   |
|                                     | 0.51 – 4.0    | 4                           | 10   | 8         | 25   | 15        | 45  | 30        | 60   | 50        | 100  | 100       | 150  |
|                                     | > 4.0         | 8                           | 25   | 15        | 40   | 35        | 70  | 60        | 100  | 100       | 140  | 150       | 180  |
| 0.41 – 0.5                          | $\leq 0.5$    | 3                           | 9    | 5         | 15   | 10        | 30  | 15        | 45   | 35        | 70   | 45        | 100  |
|                                     | 0.51 – 4.0    | 6                           | 15   | 10        | 30   | 20        | 60  | 45        | 90   | 70        | 130  | 90        | 150  |
|                                     | > 4.0         | 10                          | 30   | 20        | 40   | 40        | 80  | 90        | 120  | 120       | 150  | 150       | 180  |
| 0.51 – 0.6                          | $\leq 0.5$    | 3                           | 9    | 7         | 20   | 10        | 30  | 25        | 75   | 40        | 100  | 50        | 120  |
|                                     | 0.51 – 4.0    | 6                           | 20   | 15        | 45   | 20        | 60  | 50        | 100  | 80        | 140  | 100       | 150  |
|                                     | > 4.0         | 10                          | 30   | 30        | 60   | 45        | 90  | 100       | 150  | 140       | 180  | 160       | 200  |
| 0.61 – 0.7                          | $\leq 0.5$    | 4                           | 10   | 9         | 30   | 15        | 40  | 30        | 100  | 50        | 120  | 60        | 150  |
|                                     | 0.51 – 4.0    | 8                           | 15   | 20        | 40   | 30        | 60  | 60        | 100  | 90        | 140  | 100       | 150  |
|                                     | > 4.0         | 15                          | 35   | 40        | 80   | 60        | 100 | 100       | 150  | 140       | 180  | 160       | 200  |
| > 0.7                               | $\leq 0.5$    | 5                           | 15   | 10        | 30   | 20        | 60  | 40        | 100  | 60        | 120  | 70        | 150  |
|                                     | 0.51 – 4.0    | 10                          | 30   | 20        | 60   | 40        | 80  | 70        | 120  | 100       | 150  | 120       | 150  |
|                                     | > 4.0         | 20                          | 45   | 40        | 80   | 60        | 100 | 100       | 150  | 150       | 180  | 170       | 220  |

Table G-49—Corrosion Rate Multiplier for High Amine Strengths

| Type of Amine | Concentration (st%) | Multiplier |
|---------------|---------------------|------------|
| MEA           | $\leq 20$           | 1.0        |
|               | 21 – 25             | 1.5        |
|               | > 25                | 2.0        |
| DEA           | $\leq 30$           | 1.0        |
|               | 31 – 40             | 1.2        |
|               | > 40                | 1.5        |
| MDEA          | $\leq 50$           | 1.0        |

Table G-50—Estimated Corrosion Rates for Stainless Steel for all Amines

| Acid Gas Loading<br>(mol/mol) | Temperature (°F)<br>≤ 300 |
|-------------------------------|---------------------------|
| < 0.1                         | 1                         |
| 0.1 – 0.2                     | 1                         |
| 0.21 – 0.3                    | 1                         |
| 0.31 – 0.4                    | 2                         |
| 0.41 – 0.5                    | 2                         |
| 0.51 – 0.6                    | 3                         |
| 0.61 – 0.7                    | 4                         |
| > 0.7                         | 5                         |

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9. C. Rooney, T. R. Bacon, and M. S. DuPart, "Effect of Heat Stable Salts on MDEA Solution Corrosivity," *Hydrocarbon Processing*, March 1996, pp. 95.
10. G. McCullough and R. B. Nielsen, "Contamination and Purification of Alkaline Gas Treating Solutions," NACE Paper No. 396, Corrosion/96.
11. M.J. Litschewski, "More Experiences With Corrosion and Fouling in a Refinery Amine System," NACE Paper No. 391, Corrosion/96.

**G.13 High Temperature Oxidation****G.13.1 DESCRIPTION OF DAMAGE**

Corrosion due to high temperature oxidation occurs at temperatures above about 900°F for carbon steel and increasing higher temperatures for alloys. The metal loss occurs as a result of the reaction of metal with oxygen in the environment. Typically, at temperatures just above the temperature where oxidation begins to occur, a dense comparatively protective oxide forms on the surface that reduces the metal loss rate. The oxide scale tends to be significantly more protective as the chromium concentration in the metal increases.

**G.13.2 BASIC DATA**

The data listed in Table G-51 is required to estimate the oxidation rate.

**G.13.3 DETERMINATION OF ESTIMATED CORROSION RATES FOR HIGH TEMPERATURE OXIDATION**

Tables G-52A and G-52B can be used to determine the estimated oxidation rates knowing the material of construction and the metal temperature.

Table G-51—Basic Data Required for Analysis of High Temperature Oxidation Corrosion

| Basic Data                     | Comments                                                                                                         |
|--------------------------------|------------------------------------------------------------------------------------------------------------------|
| Material of Construction       | Determine the material of construction of this equipment/piping.                                                 |
| Maximum Metal Temperature (°F) | Determine the maximum metal temperature. The tube metal temperature for furnace tubes is the controlling factor. |

Table G-52A—Estimated Corrosion Rate for Oxidation

| Material of Construction         | Corrosion Rate (mpy)           |            |             |             |             |             |             |             |             |             |             |             |
|----------------------------------|--------------------------------|------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
|                                  | Maximum Metal Temperature (°F) |            |             |             |             |             |             |             |             |             |             |             |
|                                  | 900 – 950                      | 951 – 1000 | 1001 – 1050 | 1051 – 1100 | 1101 – 1150 | 1151 – 1200 | 1201 – 1250 | 1251 – 1300 | 1301 – 1350 | 1351 – 1400 | 1401 – 1450 | 1451 – 1500 |
| CS                               | 2                              | 4          | 6           | 9           | 14          | 22          | 33          | 48          | —           | —           | —           | —           |
| 1 <sup>1</sup> / <sub>4</sub> Cr | 2                              | 3          | 4           | 7           | 12          | 18          | 30          | 46          | —           | —           | —           | —           |
| 2 <sup>1</sup> / <sub>4</sub> Cr | 1                              | 1          | 2           | 4           | 9           | 14          | 24          | 41          | —           | —           | —           | —           |
| 5 Cr                             | 1                              | 1          | 1           | 2           | 4           | 6           | 15          | 35          | 65          | —           | —           | —           |
| 7 Cr                             | 1                              | 1          | 1           | 1           | 1           | 2           | 3           | 6           | 17          | 37          | 60          | —           |
| 9 Cr                             | 1                              | 1          | 1           | 1           | 1           | 1           | 1           | 2           | 5           | 11          | 23          | 40          |
| 12 Cr                            | 1                              | 1          | 1           | 1           | 1           | 1           | 1           | 1           | 3           | 8           | 15          | 30          |
| 304 SS                           | 1                              | 1          | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 2           | 3           | 4           |
| 309 SS                           | 1                              | 1          | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 2           | 3           |
| 310 SS/HK                        | 1                              | 1          | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 2           |
| 800 H/HP                         | 1                              | 1          | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 1           | 2           |

Table G-52B—Estimated Corrosion Rate for Oxidation

| Material of Construction         | Corrosion Rate (mpy)           |            |            |            |            |            |            |            |            |            |            |            |            |
|----------------------------------|--------------------------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
|                                  | Maximum Metal Temperature (°F) |            |            |            |            |            |            |            |            |            |            |            |            |
|                                  | 1501– 1550                     | 1551– 1600 | 1601– 1650 | 1651– 1700 | 1701– 1750 | 1751– 1800 | 1801– 1850 | 1851– 1900 | 1901– 1950 | 1951– 2000 | 2001– 2050 | 2051– 2100 | 2101– 2150 |
| CS                               | —                              | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          |
| 1 <sup>1</sup> / <sub>4</sub> Cr | —                              | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          |
| 2 <sup>1</sup> / <sub>4</sub> Cr | —                              | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          |
| 5 Cr                             | —                              | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          |
| 7 Cr                             | —                              | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          |
| 9 Cr                             | 60                             | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          |
| 12 Cr                            | 50                             | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          | —          |
| 304 SS                           | 6                              | 9          | 13         | 18         | 25         | 35         | 48         | —          | —          | —          | —          | —          | —          |
| 309 SS                           | 4                              | 6          | 8          | 10         | 13         | 16         | 20         | 30         | 40         | 50         | —          | —          | —          |
| 310 SS/HK                        | 3                              | 4          | 5          | 7          | 8          | 10         | 13         | 15         | 19         | 23         | 27         | 31         | 37         |
| 800 H/HP                         | 3                              | 4          | 6          | 8          | 10         | 13         | 17         | 21         | 27         | 33         | 41         | 50         | 60         |

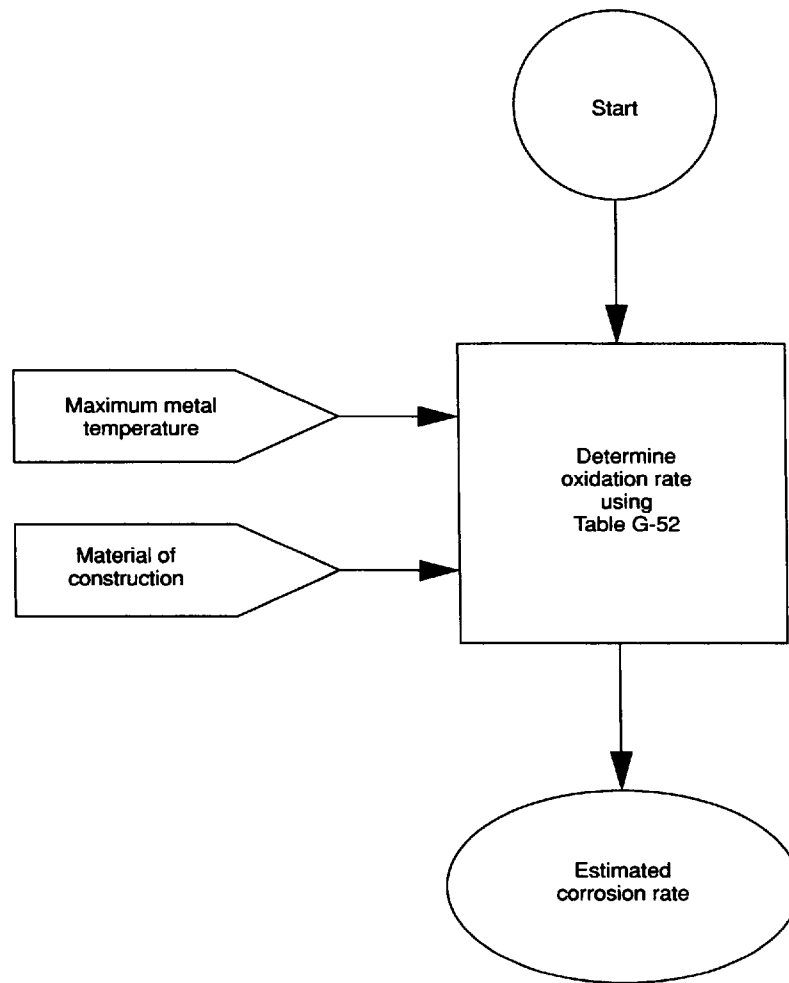


Figure G-9—Determination of Oxidation Rate



## APPENDIX H—STRESS CORROSION CRACKING TECHNICAL MODULE

### H.1 Scope

This module establishes a technical module subfactor (likelihood of failure modifier) for process equipment subject to damage by mechanisms that result in stress corrosion cracking (SCC). Caustic cracking, amine cracking, sulfide stress cracking (SSC), hydrogen-induced cracking (HIC), stress-oriented hydrogen-induced cracking (SOHIC), carbonate cracking, polythionic acid cracking (PTA), and chloride cracking (CISCC) are within the scope of the module. Technical Supplements are included in this module to provide estimates of the susceptibility to specific damage mechanisms that result in stress corrosion cracking. Expert advice may also be used to establish susceptibility to stress corrosion cracking.

### H.2 Technical Module Screening Questions

There are no screening questions to bypass the Technical Module for stress corrosion cracking. All equipment must enter this Technical Module.

#### H.2.1 REQUIRED DATA

The basic data listed in Table H-1 are the minimum required to determine a technical module subfactor for stress corrosion cracking.

#### H.2.2 ADDITIONAL DATA

Additional data are required to answer the screening questions for the SCC mechanisms listed in Table H-2. Further data required for each SCC mechanism are listed in the basic data table near the beginning of each supplement.

### H.3 Basic Assumptions

This Technical Module assumes that a susceptibility to each SCC mechanism is determined in the applicable section of this module. The susceptibility is designated as high, medium, or low based on process, material, and fabrication variables. A "severity index" can be determined which is the product of the susceptibility of the equipment/piping to cracking (or the likelihood of initiating cracks) and the likelihood of a crack resulting in a leak.

The method can also handle known cracks in a simplistic manner. Likelihood of failure due to a specific crack or array of cracks in the equipment/piping should be further evaluated using more advanced methods and fitness for service evaluations.

### H.4 Determination of Technical Module Subfactor (TMSF)

A flow chart of the steps required to determine the technical module subfactor is presented in Figures H-1A and H-1B. These steps are discussed below, along with the required tables.

#### H.4.1 SCREENING QUESTION FOR TECHNICAL SUPPLEMENTS

The screening questions listed in Table H-2 are used to select the applicable SCC mechanism.

#### H.4.2 DETERMINATION OF SUSCEPTIBILITY FOR EACH POTENTIAL SCC MECHANISM

The individual section for each SCC mechanism will establish a susceptibility that is possible in this equipment.

##### H.4.2.1 Adjustment for Existing Cracking

If SCC has been detected in this equipment, then the susceptibility is considered high. If the mechanism of the detected SCC is known, then the susceptibility of that mechanism should be increased to high. If the mechanism of the detected SCC is not known, then the susceptibility for cracking of all potential mechanisms should be increased to high.

#### H.4.3 DETERMINATION OF SEVERITY INDEX

Use the susceptibility for each SCC mechanism to enter Table H-3 and determine the severity index for each potential/existing SCC mechanism.

The severity index for equipment with no inspection is outlined below for each of the stress cracking mechanisms.

##### H.4.3.1 Maximum Severity Index

Determine the maximum severity index and which mechanism resulted in the highest severity index.

#### H.4.4 INSPECTION EFFECTIVENESS

Inspections are ranked according to the expected effectiveness of detecting cracking. The actual effectiveness of a given inspection technique or combination of techniques depends on the characteristics of the specific cracking mechanism and other factors.

Tables H-4A through H-4F provide examples of inspection activities that are both intrusive (requires entry into equipment) and nonintrusive (can be performed externally). Note that the effectiveness categories vary somewhat for each cracking mechanism.

Table H-1—Basic Data Required for Analysis of Stress Corrosion Cracking

| Basic Data                                                                                                         | Comments                                                                                                                                                                                              |
|--------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Susceptibility to SCC (Low, Medium, High)                                                                          | The susceptibility is determined by each of the applicable Technical Supplements or by expert advice.                                                                                                 |
| Operating Pressure, (psi)                                                                                          | The highest expected operating pressure (may be the relief valve set pressure unless pressures at that level are unlikely).                                                                           |
| MAWP (psi)                                                                                                         | The pressure used to determine the minimum allowable wall thickness. If MAWP is not available, design pressure may be used for this input.                                                            |
| Material of Construction                                                                                           | The material of construction of the equipment from the inspection records.                                                                                                                            |
| Operating Temperature (°F)                                                                                         | The highest expected operating temperature expected during operation (consider normal and non-normal operating conditions).                                                                           |
| Presence of SCC and Cracking Mechanism (if known) (Caustic, Amine, SSC, HIC/SOHIC, Carbonate, PTA, CISCC, Unknown) | Attempt to determine the cracking mechanism from inspection records, failure analysis reports, or expert advice. If the cause of cracking is not known, a more conservative damage factor may result. |
| Time since last SCC inspection (years)                                                                             | Use inspection history to determine years since the last SCC inspection.                                                                                                                              |
| Inspection Effectiveness Category                                                                                  | The effectiveness category that has been performed on the equipment. See Tables H-4 for guidelines to assign inspection effectiveness categories for each of the SCC mechanisms.                      |
| On-Line Monitoring (Hydrogen Probes, Process Variables, or Combination)                                            | The type of proactive corrosion monitoring methods or tools employed, such as hydrogen probes and/or process variable monitoring.                                                                     |
| Number of Inspections                                                                                              | The number of inspections in each effectiveness category that have been performed.                                                                                                                    |

Table H-2 —Screening Questions for SCC Mechanisms

| Screening Questions                                                                                                                                                | Action                                    |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------|
| 1. Caustic Cracking                                                                                                                                                | If Yes to both, proceed to H.5.           |
| Is the material carbon or low alloy steel?                                                                                                                         |                                           |
| Does the environment contain caustic in any concentration?                                                                                                         |                                           |
| 2. Amine Cracking                                                                                                                                                  |                                           |
| Is the material of construction carbon or low alloy steel?                                                                                                         |                                           |
| Is the equipment exposed to acid gas treating amines (MEA, DEA, DIPA, MDEA, etc.)?                                                                                 | If Yes to both, proceed to H.6.           |
| 3. SSC/HIC/SOHIC                                                                                                                                                   |                                           |
| Is the material of construction carbon or low alloy steel?                                                                                                         |                                           |
| Does the environment contain water and H <sub>2</sub> S?                                                                                                           | If Yes to both, proceed to H.7 and H.8.   |
| 4. Carbonate Cracking                                                                                                                                              |                                           |
| Is the material of construction carbon steel?                                                                                                                      | If Yes to both, proceed to H.9.           |
| Does the environment contain sour water at pH > 7.5?                                                                                                               |                                           |
| 5. Polythionic Acid Cracking (PTA)                                                                                                                                 | If Yes to both, proceed to H.10.          |
| Is the material austenitic stainless steel or nickel based alloys?                                                                                                 |                                           |
| Is the equipment exposed to sulfur bearing compounds?                                                                                                              |                                           |
| 6. Chloride Stress Corrosion Cracking (CISCC)                                                                                                                      | If Yes to all, proceed to H.11.           |
| Is the material austenitic stainless steel?                                                                                                                        |                                           |
| Is the equipment exposed or potentially exposed to chlorides and water also considering upsets and hydrotest water remaining in equipment for process conditions)? |                                           |
| Is the operating temperature between 100°F and 300°F?                                                                                                              |                                           |
| 7. Hydrogen Stress Cracking (HSC-HF, HIC/SOHIC-HF)                                                                                                                 | If Yes to both, proceed to H.12 and H.13. |
| Is the material carbon or low alloy steel?                                                                                                                         |                                           |
| Is the equipment exposed to hydrofluoric acid?                                                                                                                     |                                           |

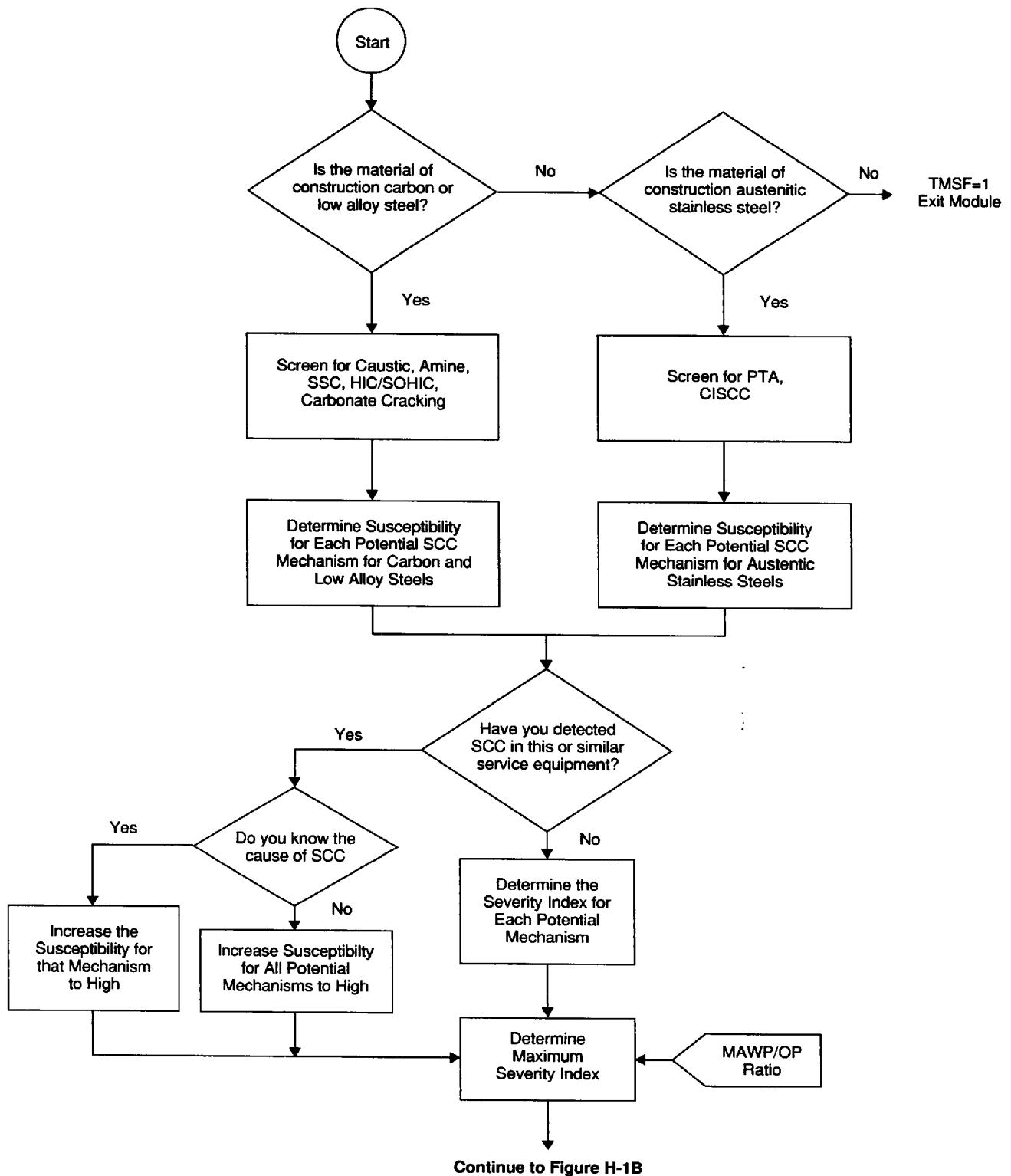


Figure H-1A—Determination of Technical Module Subfactor for Stress Corrosion Cracking

Continued from Figure H-1A

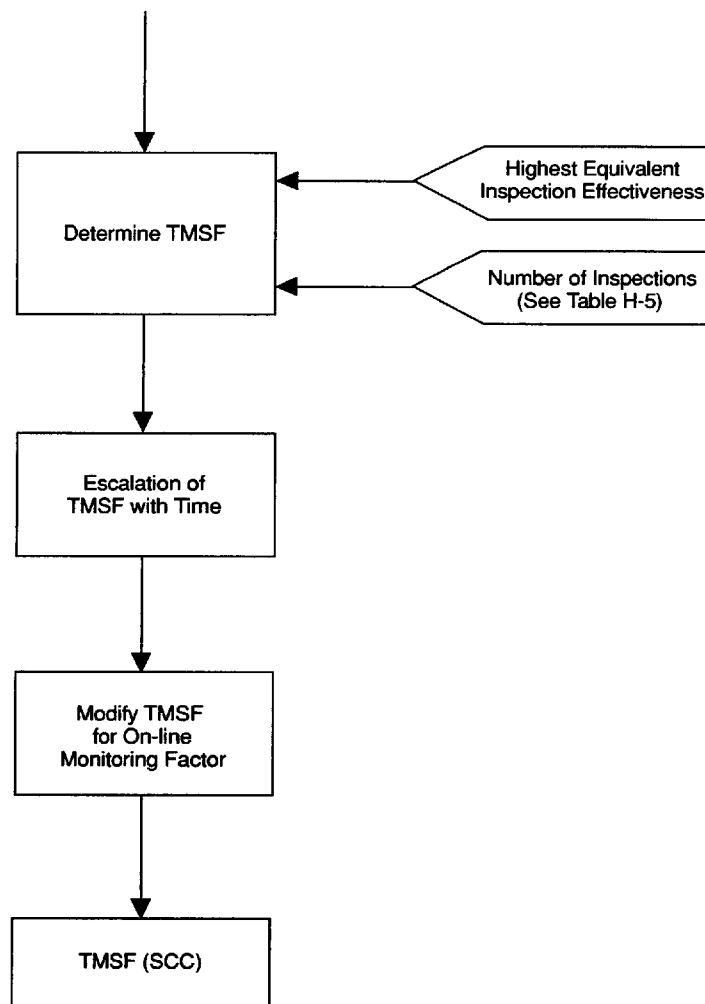


Figure H-1B—Determination of Technical Module Subfactor for Stress Corrosion Cracking

Table H-3—Determination of Severity Index

| Susceptibility | Severity Index |       |           |             |               |       |      |
|----------------|----------------|-------|-----------|-------------|---------------|-------|------|
|                | Caustic        | Amine | Carbonate | SSC, HSC-HF | HIC/<br>SOHIC | CISCC | PTA  |
| High           | 5000           | 1000  | 1000      | 100         | 100           | 5000  | 5000 |
| Medium         | 500            | 100   | 100       | 10          | 10            | 500   | 500  |
| Low            | 50             | 10    | 10        | 1           | 1             | 50    | 50   |
| Not            | 1              | 1     | 1         | 1           | 1             | 1     | 1    |

Table H-4A—Effectiveness of Inspection for Caustic Cracking

| Inspection Effectiveness Category | Example:<br>Intrusive Inspection                                                                                                                    | Example:<br>Nonintrusive Inspection                                                                                               |
|-----------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | Wet fluorescent Magnetic particle or dye penetrant testing of 25–100% of welds/cold bends; or Dye penetrant testing of 25–100% of welds/cold bends. | Shear wave ultrasonic testing of 25–100% of welds/cold bends; or Radiographic testing of 50–100% of welds/cold bends.             |
| Usually Effective                 | Wet fluorescent Magnetic particle or dye penetrant testing of 10–24% of welds/cold bends; or Dye penetrant testing of 10–24% of welds/cold bends.   | Shear wave ultrasonic testing of 10–24% of welds/cold bends; or Radiographic testing of 25–49% of welds/cold bends.               |
| Fairly Effective                  | Magnetic particle or dye penetrant testing of less than 10% of welds/cold bends; or Dye penetrant testing of less than 10% of welds/cold bends.     | Shear wave ultrasonic testing of less than 10% of welds/cold bends; or Radiographic testing of less than 25% of welds/cold bends. |
| Poorly Effective                  | Visual inspection                                                                                                                                   | Visual inspection for leaks                                                                                                       |
| Ineffective                       | No inspection                                                                                                                                       | No inspection                                                                                                                     |

Table H-4B—Effectiveness of Inspection for Amine Cracking &amp; Carbonate Cracking

| Inspection Effectiveness Category | Example:<br>Intrusive Inspection                                                                                                                                                                          | Example:<br>Nonintrusive Inspection                                                                                          |
|-----------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | Wet fluorescent magnetic particle testing of 100% of repair welds and 50–100% of other welds/cold bends.                                                                                                  | None                                                                                                                         |
| Usually Effective                 | Wet fluorescent magnetic particle testing of 20–49% of welds/cold bends.                                                                                                                                  | Shear wave ultrasonic testing of 50–100% of welds/cold bends; or Acoustic Emission testing with follow-up shear wave UT.     |
| Fairly Effective                  | Wet fluorescent magnetic particle testing of less than 20% of welds/cold bends; or Dry magnetic particle testing of 50–100% of welds/cold bends; or Dye penetrant testing of 50–100% of welds/cold bends. | Shear wave ultrasonic testing of 20–49% of welds/cold bends.                                                                 |
| Poorly Effective                  | Dry magnetic particle testing of less than 50% of welds/cold bends; or Dye penetrant testing of less than 50% of welds/cold bends.                                                                        | Shear wave ultrasonic testing of less than 20% of welds/cold bends; or Radiographic testing; or Visual inspection for leaks. |
| Ineffective                       | Visual inspection                                                                                                                                                                                         | No inspection                                                                                                                |

Table H-4C—Effectiveness of Inspection for Sulfide Stress Cracking and Hydrogen Stress Cracking

| Inspection Effectiveness Category | Example:<br>Intrusive Inspection                                                                                                                                                                 | Example:<br>Nonintrusive Inspection                                                                                                                                              |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | Wet fluorescent magnetic particle testing of 25–100% of weldments.                                                                                                                               | Shear wave ultrasonic testing of 25–100% of weldments, transverse and parallel to the weld with the weld cap removed; or Acoustic Emission testing with follow-up shear wave UT. |
| Usually Effective                 | Wet fluorescent magnetic particle testing of 10–24% of weldments; or Dry magnetic particle testing of 25–100% of weldments; or Dye penetrant testing of 25–100% of weldments.                    | Shear wave ultrasonic testing of 10–24% of weldments; Radiographic testing of 50–100% of weldments.                                                                              |
| Fairly Effective                  | Wet fluorescent magnetic particle testing of less than 10% of weldments; or Dry magnetic particle testing of less than 25% of weldments; or Dye penetrant testing of less than 25% of weldments. | Shear wave ultrasonic testing of less than 10% of weldments; Radiographic testing of 20–49% of weldments.                                                                        |
| Poorly Effective                  | Visual inspection                                                                                                                                                                                | Radiographic testing of less than 20% of weldments.                                                                                                                              |
| Ineffective                       | No inspection                                                                                                                                                                                    | No inspection                                                                                                                                                                    |

Table H-4D—Effectiveness of Inspection for HIC/SOHIC and HIC/SOHIC-HF

| Inspection Effectiveness Category | Example:<br>Intrusive Inspection                                                                                                                                                     | Example:<br>Nonintrusive Inspection                                                                                                     |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | Wet fluorescent magnetic particle testing of 50–100% of weldments, plus additional shear wave UT for subsurface cracking.                                                            | None                                                                                                                                    |
| Usually Effective                 | Wet fluorescent magnetic particle testing of 20–49% of weldments.                                                                                                                    | Automated shear wave ultrasonic testing of 20–100% of weldments; or Acoustic Emission testing with follow-up shear wave UT.             |
| Fairly Effective                  | Wet fluorescent magnetic particle testing of less than 20% of weldments; or Dry magnetic particle testing of 50–100% of weldments; or Dye penetrant testing of 50–100% of weldments. | Automated shear wave ultrasonic testing of less than 20% of weldments; or Manual shear wave ultrasonic testing of 20–100% of weldments. |
| Poorly Effective                  | Dye penetrant testing of less than 50% of weldments; Visual inspection for hydrogen blisters.                                                                                        | Manual shear wave ultrasonic testing of less than 20% of weldments.                                                                     |
| Ineffective                       | No inspection                                                                                                                                                                        | Radiographic testing                                                                                                                    |

Table H-4E—Effectiveness of Inspection for PTA<sup>a</sup>

| Inspection Effectiveness Category | Example:<br>Intrusive Inspection | Example:<br>Nonintrusive Inspection                       |
|-----------------------------------|----------------------------------|-----------------------------------------------------------|
| Highly Effective                  | Dye penetrant (25%+)             | Radiography (25%+)<br>Shear wave ultrasonics (25%+)       |
| Usually Effective                 | Dye penetrant testing            | Radiography approx. (5%)<br>Shear wave ultrasonics (25%+) |
| Fairly Effective                  | Dye penetrant (10%)              | Spot Radiography<br>Spot shear wave ultrasonics           |
| Poorly Effective                  | Visual                           | Visual for leaks                                          |
| Ineffective                       | No Inspection                    | No Inspection                                             |

<sup>a</sup>There is no highly effective inspection without a minimum of partial insulation removal and external VT and PT.

Table H-4F—Effectiveness of Inspection for CISCC

| Inspection Effectiveness Category | Example:<br>Intrusive Inspection                     | Example:<br>Non-intrusive Inspection                                                                                                                          |
|-----------------------------------|------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | Dye penetrant testing of 50% to 100% of weldments.   | Shear wave ultrasonic testing of 25% to 100% of weldments, transverse and parallel to the weld with the weld cap removed.                                     |
| Usually Effective                 | Dye penetrant testing of 25% to 50% of weldments.    | Shear wave ultrasonic testing of 10% to 24% of weldments, radiographic testing of 50% to 100% of weldments.<br>AE test with partial insulation removal and PT |
| Fairly Effective                  | Dye penetrant testing of less than 25% of weldments. | Shear wave ultrasonic testing of less than 10% of weldments, radiographic testing of 20% to 49% of weldments.                                                 |
| Poorly Effective                  | Visual                                               | Visual for Leaks                                                                                                                                              |
| Ineffective                       | No Inspection                                        | No Inspection                                                                                                                                                 |

#### H.4.5 ESCALATION OF TECHNICAL MODULE WITH TIME

It is assumed that the likelihood for cracking would increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. Therefore, the TMSF should be increased by the following relationship:

Final TMSF = TMSF \* (years since last inspection for cracking)

As an example, a piece of equipment/piping with a TMSF of 10 would increase to a Final TMSF of 58 in five years without any inspection and would increase further to 125 after ten years without inspection. This escalation factor should not be applied to PTA.

#### H.4.6 ADJUSTMENT TO TECHNICAL MODULE SUBFACTOR FOR ON-LINE MONITORING

In addition to inspection, on-line monitoring using hydrogen probes and/or key process variables affect HIC/SOHIC susceptibility. The advantage of on-line monitoring is that changes in SCC susceptibility as a result of process changes can be detected before significant cracking damage occurs. This earlier detection usually permits more timely action to be taken that should decrease the likelihood of failure. For HIC/SOHIC, an on-line monitoring factor of 2 is applied if either hydrogen probes or monitoring of key process variables are used. If both hydrogen probes and monitoring key process variables are used, an on-line monitoring factor of 4 is applied. Divide the TMSF by this factor. Do not apply this factor if the TMSF is 1. No on-line monitoring factor should be applied for any other stress corrosion cracking mechanism.

Table H-5—Technical Module Subfactor Determination

| No. of Inspections     |               | 1                        |        |         |        | 2                        |        |         |        | 3                        |        |         |        | 4                        |        |         |        | 5                        |        |         |        | 6                        |        |         |        |
|------------------------|---------------|--------------------------|--------|---------|--------|--------------------------|--------|---------|--------|--------------------------|--------|---------|--------|--------------------------|--------|---------|--------|--------------------------|--------|---------|--------|--------------------------|--------|---------|--------|
|                        |               | Inspection Effectiveness |        |         |        | Inspection Effectiveness |        |         |        | Inspection Effectiveness |        |         |        | Inspection Effectiveness |        |         |        | Inspection Effectiveness |        |         |        | Inspection Effectiveness |        |         |        |
| Maximum Severity Index | No Inspection | Poorly                   | Fairly | Usually | Highly | Poorly                   | Fairly | Usually | Highly | Poorly                   | Fairly | Usually | Highly | Poorly                   | Fairly | Usually | Highly | Poorly                   | Fairly | Usually | Highly | Poorly                   | Fairly | Usually | Highly |
| 1                      | 1             | 1                        | 1      | 1       | 1      | 1                        | 1      | 1       | 1      | 1                        | 1      | 1       | 1      | 1                        | 1      | 1       | 1      | 1                        | 1      | 1       | 1      | 1                        | 1      | 1       | 1      |
| 10                     | 10            | 8                        | 3      | 1       | 1      | 6                        | 2      | 1       | 1      | 4                        | 1      | 1       | 1      | 2                        | 1      | 1       | 1      | 1                        | 1      | 1       | 1      | 1                        | 1      | 1       | 1      |
| 50                     | 50            | 40                       | 17     | 5       | 3      | 30                       | 10     | 2       | 1      | 20                       | 5      | 1       | 1      | 10                       | 2      | 1       | 1      | 5                        | 1      | 1       | 1      | 1                        | 1      | 1       | 1      |
| 100                    | 100           | 80                       | 33     | 10      | 5      | 60                       | 20     | 4       | 1      | 40                       | 10     | 2       | 1      | 20                       | 5      | 1       | 1      | 10                       | 2      | 1       | 1      | 5                        | 1      | 1       | 1      |
| 500                    | 500           | 400                      | 170    | 50      | 25     | 300                      | 100    | 20      | 5      | 200                      | 50     | 8       | 1      | 100                      | 25     | 2       | 1      | 50                       | 10     | 1       | 1      | 25                       | 5      | 1       | 1      |
| 1,000                  | 1,000         | 800                      | 330    | 100     | 50     | 600                      | 200    | 40      | 10     | 400                      | 100    | 16      | 2      | 200                      | 50     | 5       | 1      | 100                      | 25     | 2       | 1      | 50                       | 10     | 1       | 1      |
| 5,000                  | 5,000         | 4,000                    | 1,670  | 500     | 250    | 3,000                    | 1,000  | 250     | 50     | 2,000                    | 500    | 80      | 10     | 1,000                    | 250    | 25      | 2      | 500                      | 125    | 5       | 1      | 250                      | 50     | 2       | 1      |

## H.5 Caustic Cracking

### H.5.1 DESCRIPTION OF DAMAGE

Caustic cracking is defined as cracking of a metal under the combined action of tensile stress and corrosion in the presence of sodium hydroxide (NaOH) at elevated temperature. The cracking is predominantly intergranular in nature, and typically occurs as a network of fine cracks in carbon steels. Low alloy ferritic steels have similar cracking susceptibility. There are three key parameters that determine susceptibility of steel fabrications to caustic cracking. They are caustic concentration, metal temperature, and level of tensile stress. Industry experience indicates that some caustic cracking failures occur in a few days, while many require prolonged exposure of one or more years. Increasing the caustic concentration or metal temperature accelerates the cracking rate.

Figure H-3 provides information on the caustic cracking susceptibility of carbon steel. Caustic cracking of steel is not anticipated at metal temperatures less than about 115°F. In the 115°F to 180°F range, cracking susceptibility is a function of the caustic concentration. Above 180°F, cracking susceptibility is a function of the caustic concentration. Above 180°F cracking is highly likely for all concentrations above about 5% wt. Although cracking susceptibility is significantly lower in caustic solutions with less than 5% concentration, presence of high temperatures (approaching boiling) can cause locally higher concentrations which would increase cracking susceptibility. Notable case histories of this phenomenon include caustic cracking of distillation columns when caustic is added to the column for pH control, and caustic cracking of boiler feedwater equipment or piping bolts when gasket leaks expose the bolts to feedwater leaks. With regard to temperature, the key consideration is the actual metal temperature, and not just the normal process temperature. There are many case histories of caustic cracking of "ambient temperature" caustic equipment that was heat traced or steamed out while still containing caustic.

As-welded or as-bent carbon and low alloy steel assemblies are susceptible to caustic cracking because of the high level of residual stress remaining after fabrication by these methods. Application of a post-fabrication stress-relieving heat treatment (e.g. postweld heat treatment) is a proven method of preventing caustic cracking. A heat treatment of about 1150°F for one hour per inch of thickness (one hour minimum) is considered an effective stress-relieving heat treatment to prevent caustic cracking of carbon steel.

### H.5.2 BASIC DATA

The data listed in Table H-6 are required to determine the susceptibility of carbon and low alloy ferritic steel equipment and piping to caustic cracking. If exact process data are not known, contact a knowledgeable process engineer to obtain the best estimates.

### H.5.3 DETERMINATION OF SUSCEPTIBILITY TO CAUSTIC CRACKING

Using basic data from Table H-6, enter the decision tree in Figure H-2 to determine the susceptibility to caustic cracking.

#### References

1. *Corrosion Data Survey—Metals Section*, NACE International, Houston, TX, Fifth Edition (March 1974), p. 274.
2. NACE-5, *Stress Corrosion Cracking of Hydrogen Embrittlement of Iron Base Alloys*, Edited by R.W. Staehle, et. al., NACE International, Houston, TX, 1977, pp. 583-587.
3. P. Gegner, "Corrosion Resistance of Materials in Alkalies and Hypochlorites," *Process Industries Corrosion*, NACE International, Houston TX, 1975, pp. 296-305.
4. J. K. Nelson, "Materials of Construction for Alkalies and Hypochlorites," *Process Industries Corrosion—The Theory and Practice*, NACE International, Houston, TX, 1986, pp. 297-310.

Table H-6—Basic Data Required for Analysis of Caustic Cracking

| Basic Data                       | Comments                                                                                                                                                                          |
|----------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| NaOH Concentration (%)           | Determine the concentration of the caustic solution being handled in this equipment/piping. Take into account whether heating or flashing of water produces higher concentration. |
| Maximum Process Temperature (°F) | Determine the maximum process temperature in this equipment/piping. Consider local heating due to mixing if at a caustic injection point.                                         |
| Heat Traced?<br>(Yes or No)      | Determine whether the equipment/piping is steam-traced or electric-traced (e.g. for freeze protection).                                                                           |
| Steamed out?<br>(Yes or No)      | Determine whether the equipment/piping has been steamed out prior to water flushing to remove residual caustic.                                                                   |
| Stress Relieved?<br>(Yes or No)  | Determine whether the equipment/piping has been properly stress relieved after welding and cold forming.                                                                          |



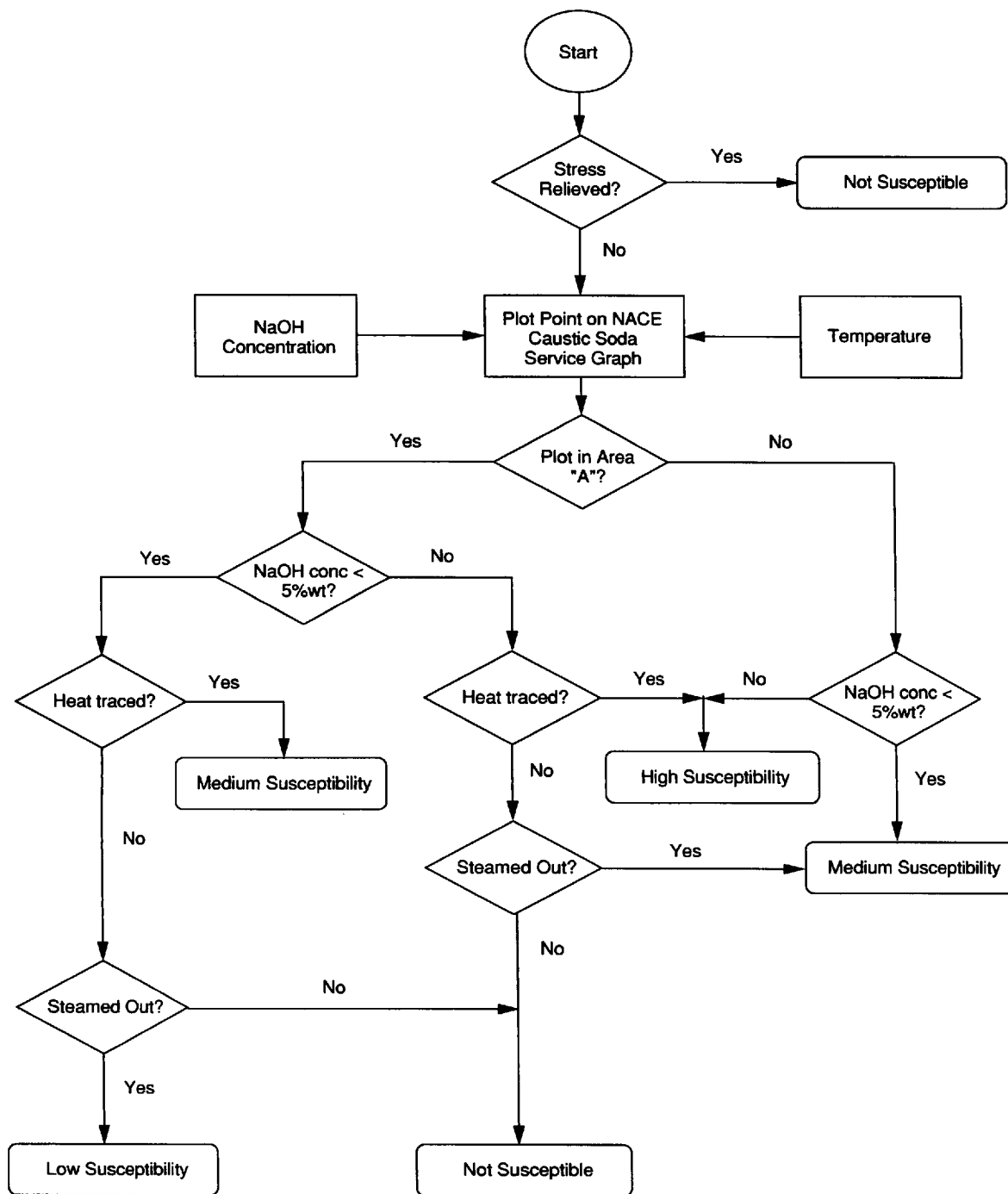


Figure H-2—Determination of Susceptibility to Caustic Cracking

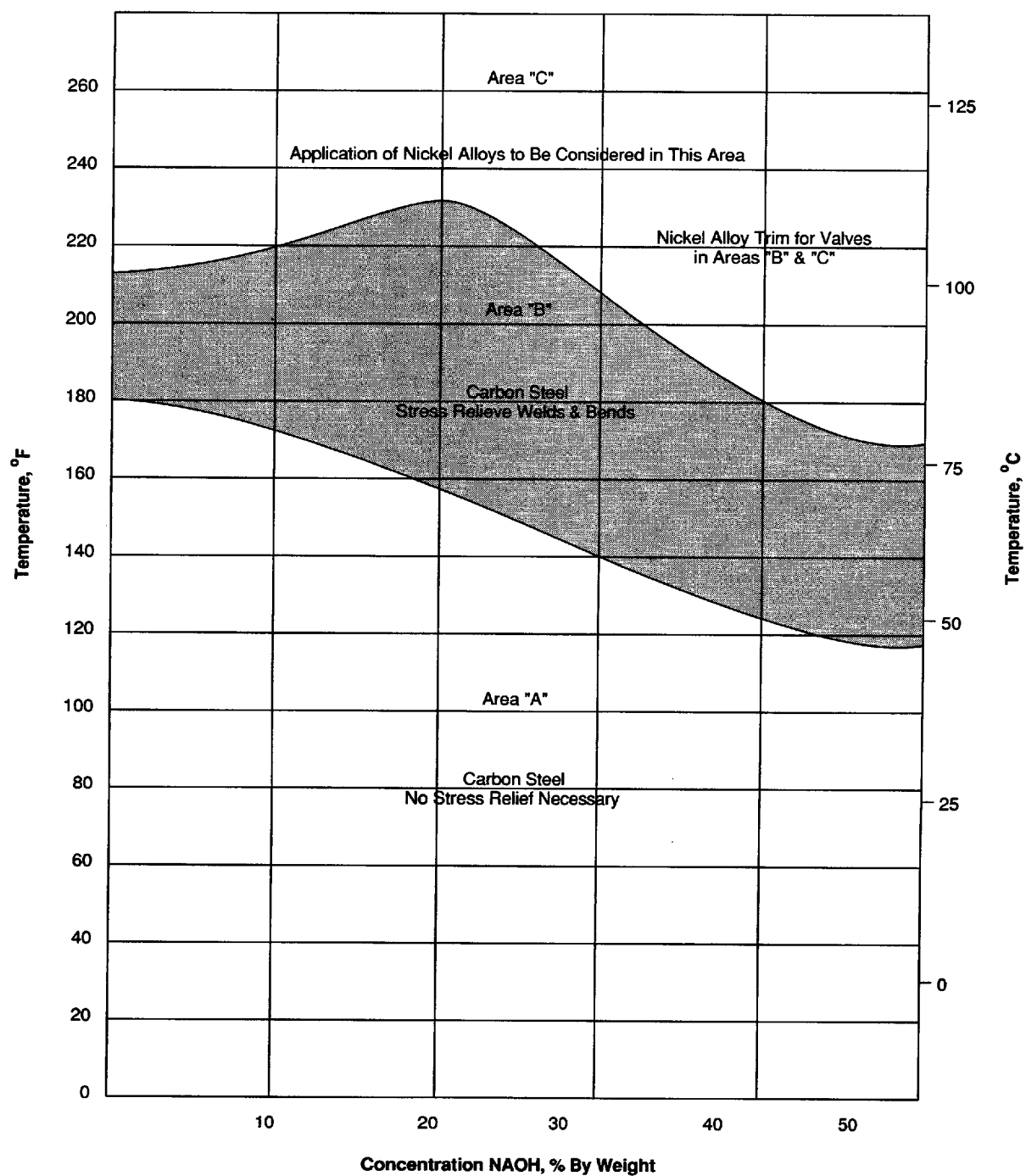


Figure H-3—Caustic Soda Service Graph

## H.6 Amine Cracking

### H.6.1 DESCRIPTION OF DAMAGE

Amine cracking is defined as cracking of a metal under the combined action of tensile stress and corrosion in the presence of an aqueous alkanolamine solution at elevated temperature. The cracking is predominately intergranular in nature, and typically occurs in carbon steels as a network of very fine, corrosion product filled cracks. Low alloy ferritic steels are also susceptible to amine cracking. Amine cracking is typically observed in amine treating units which use aqueous alkanolamine solutions for removal of acid gases such as  $H_2S$  and  $CO_2$  from various gas or liquid hydrocarbon streams. Four available parameters are used to assess the susceptibility of steel fabrications to amine cracking. They are the type of amine, amine solution composition, metal temperature, and level of tensile stress.

With regard to the type of amine, results of an NACE survey indicate that amine cracking is most prevalent in monoethanolamine (MEA) and diisopropanolamine (DIPA) units, and to a somewhat lesser extent in diethanolamine (DEA) units. Cracking is much less prevalent in methyldiethanolamine (MDEA), Sulfinol, and diglycolamine (DGA) units.

Studies have concluded that the cracking occurs in a narrow range of electrochemical potential, which is very dependent upon the amine solution composition. Carbonate is a critical solution contaminant, and other contaminants such as chlorides, cyanides, etc. have been shown to affect cracking susceptibility. Despite this mechanistic understanding, the electrochemical potential of in-service equipment and piping may not be readily available. Amine concentration is a factor in cracking susceptibility in MEA solutions, where cracking susceptibility has been shown to be higher in the 15 to 35% concentration range. There is not sufficient understanding of this relationship in other amine solutions, but it is noteworthy that cracking susceptibility is lower in MDEA and Sulfinol units which typically utilize higher concentration amine solutions.

With regard to the amine solution composition, cracking typically occurs in the lean alkanolamine solution which is

alkaline and contains very low levels of acid gases. Amine cracking does not occur in fresh amine solutions, i.e., those that have not been exposed to acid gases. Amine cracking is not likely to occur in rich alkanolamine solutions, which contain high levels of acid gases. In rich amine solutions, other forms of cracking are far more prevalent (see note).

With regard to temperature, amine cracking susceptibility is generally higher at elevated temperatures. A key consideration is the actual metal temperature, and not just the normal process temperature. Cracking has occurred in equipment and piping that normally operates at low temperatures but was heat traced or steamed out prior to water washing to remove residual amine solution.

With regard to the level of tensile stress, as-welded or as-bent carbon and low alloy steel fabrications are susceptible to amine cracking because of the high level of residual stress remaining after fabrication by these methods. Application of a post-fabrication stress-relieving heat treatment (e.g., postweld heat treatment) is a proven method of preventing amine cracking. A heat treatment of about 1150°F for one hour per inch of thickness (one hour minimum) is considered an effective stress-relieving heat treatment to prevent amine cracking of carbon steel.

Note: Other forms of cracking have been reported in amine units. Most of these occurred in equipment and piping exposed to rich alkanolamine solutions and have typically been forms of hydrogen damage such as sulfide stress cracking (SSC), hydrogen-induced cracking (HIC), and stress-oriented hydrogen-induced cracking (SOHIC). These are not included here, but are dealt with in other sections of this module.

### H.6.2 BASIC DATA

The data listed in Table H-7 are required to determine the susceptibility of carbon and low alloy ferritic steel equipment and piping to amine cracking. If exact process data are not known, contact a knowledgeable process engineer to obtain the best estimates.

Table H-7—Basic Data Required for Analysis of Amine Cracking

| Basic Data                       | Comments                                                                                                                                                                                                                                                                                                                                                                      |
|----------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Type of Amine                    | Determine what type of amine is being handled in this equipment/piping.                                                                                                                                                                                                                                                                                                       |
| Amine Solution Composition       | Determine what amine solution composition is being handled in this equipment/piping. Fresh amine has not been exposed to $H_2S$ or $CO_2$ . Lean amine contains low levels of $H_2S$ or $CO_2$ . Rich amine contains high levels of $H_2S$ or $CO_2$ . For equipment exposed to both lean and rich amine solutions (i.e., amine contractors and regenerators), indicate lean. |
| Maximum Process Temperature (°F) | Determine the maximum process temperature in this equipment/piping.                                                                                                                                                                                                                                                                                                           |
| Heat traced?<br>(Yes or No)      | Determine whether the equipment/piping is steam-traced or electric-traced (e.g., for freeze protection).                                                                                                                                                                                                                                                                      |
| Steamed out?<br>(Yes or No)      | Determine whether the equipment/piping has been steamed out prior to water flushing to remove residual amine.                                                                                                                                                                                                                                                                 |
| Stress Relieved?<br>(Yes or No)  | Determine whether the equipment/piping has been properly stress relieved after welding and cold forming.                                                                                                                                                                                                                                                                      |

### H.6.3 DETERMINATION OF SUSCEPTIBILITY TO AMINE CRACKING

Using the basic data from Table H-7, enter the decision tree in Figure H-4 to determine the susceptibility to amine cracking.

#### References

1. *Avoiding Environmental Cracking in Amine Units*, API Recommended Practice 945, 1st Edition, August 1990.
2. Richert, Bagdasarian, and Shargay, "Stress Corrosion Cracking of Carbon Steel in Amine Systems," NACE paper #187, Corrosion/87 (see also "Extent of Stress Corrosion Cracking in Amine Plants Revealed by Survey", *Oil & Gas Journal*, June 5, 1989).
3. Parkins and Foroulis, "The Stress Corrosion Cracking of Mild Steel in Monoethanolamine Solutions," NACE paper #188, Corrosion/87 (see also *Materials Performance* 25, 10 (1986), pp. 20-27).
4. Lenhart, Craig, and Howell, "Diethanolamine SCC of Mild Steel," NACE paper #212, Corrosion/86.
5. Gutzeit and Johnson, "Stress Corrosion Cracking of Carbon Steel Welds in Amine Service," NACE paper #206, Corrosion/86.
6. Schutt, HU, "New Aspects of Stress Corrosion Cracking in Monoethanolamine Solutions," NACE paper #159, Corrosion/88 (see also *Materials Performance* 27, 12 (1988), pp. 53-58).
7. Bagdasarian, Shargay and Coombs, "Stress Corrosion Cracking of Carbon Steel in DEA and ADIP Solutions," *Materials Performance* 30, 5 (1991), pp. 63-67 (see also *Oil & Gas Journal*, Jan. 13, 1992, pp. 42-44).

## H.7 Sulfide Stress Cracking

### H.7.1 DESCRIPTION OF DAMAGE

Sulfide stress cracking is defined as cracking of a metal under the combined action of tensile stress and corrosion in the presence of water and hydrogen sulfide. SSC is a form of hydrogen stress cracking resulting from absorption of atomic hydrogen that is produced by the sulfide corrosion process on the metal surface. SSC usually occurs more readily in high-strength (high hardness) steels in hard weld deposits or hard heat-affected zones of lower-strength steels.

Susceptibility to SSC is related to the hydrogen permeation flux in the steel, which is primarily associated with two environmental parameters—pH and H<sub>2</sub>S content of the water. Typically, the hydrogen flux in steels has been found to be lowest in near neutral pH solutions, with increasing flux at both lower and higher pH values. Corrosion at low pH values is caused by H<sub>2</sub>S, whereas corrosion at high pH values is caused by high concentrations of the bisulfide ion. Presence of cyanides at elevated pH can further aggravate the hydrogen

penetration into the steel. SSC susceptibility is known to increase with H<sub>2</sub>S content, e.g. H<sub>2</sub>S partial pressure in the gas phase or H<sub>2</sub>S content of the water phase. The presence of as little as 1 ppm of H<sub>2</sub>S in the water has been found to be sufficient to cause SSC.

Susceptibility to SSC is primarily related to two material parameters—hardness and stress level. High hardness of the steel increases its susceptibility to SSC. SSC has not generally been a concern for carbon steel base metals typically used for refinery pressure vessels and piping in wet hydrogen sulfide service because these steels have sufficiently low strength (hardness) levels. However, weld deposits and HAZs may contain zones of high hardness and high residual stresses from welding. High residual tensile stresses associated with welds increases susceptibility to SSC. PWHT significantly reduces residual stresses and also tempers (softens) weld deposits and HAZs. A postweld heat treatment of about 1150°F for one hour per inch of thickness (one hour minimum) is considered effective for carbon steel. Somewhat higher temperatures are required for low alloy steels. Control of hardness and reduction of residual stresses are recognized methods for preventing SSC as outlined in NACE Standard RP0472.

### H.7.2 BASIC DATA

The data listed in Table H-8 are required to determine the susceptibility of carbon and low alloy ferritic steel equipment and piping to SSC. If exact process data are not known, contact a knowledgeable process engineer to obtain the best estimates.

### H.7.3 DETERMINATION OF ENVIRONMENTAL SEVERITY

If there is no water present, then the equipment/piping is considered Not Susceptible to SSC. If there is water present, then the basic data from Table H-8 on the H<sub>2</sub>S content of the water and its pH should be used to estimate the environmental severity (potential level of hydrogen flux) using Table H-9.

### H.7.4 DETERMINATION OF SUSCEPTIBILITY TO SSC

Using the environmental severity determined in Table H-9 and the basic data from Table H-8 on maximum Brinell hardness and postweld heat treatment of weldments, the susceptibility to SSC should be determined using Table H-10. A flow chart of the steps required to determine the susceptibility to SSC is presented in Figure H-5.

#### References

1. *Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments*, NACE Standard RP0472-95.

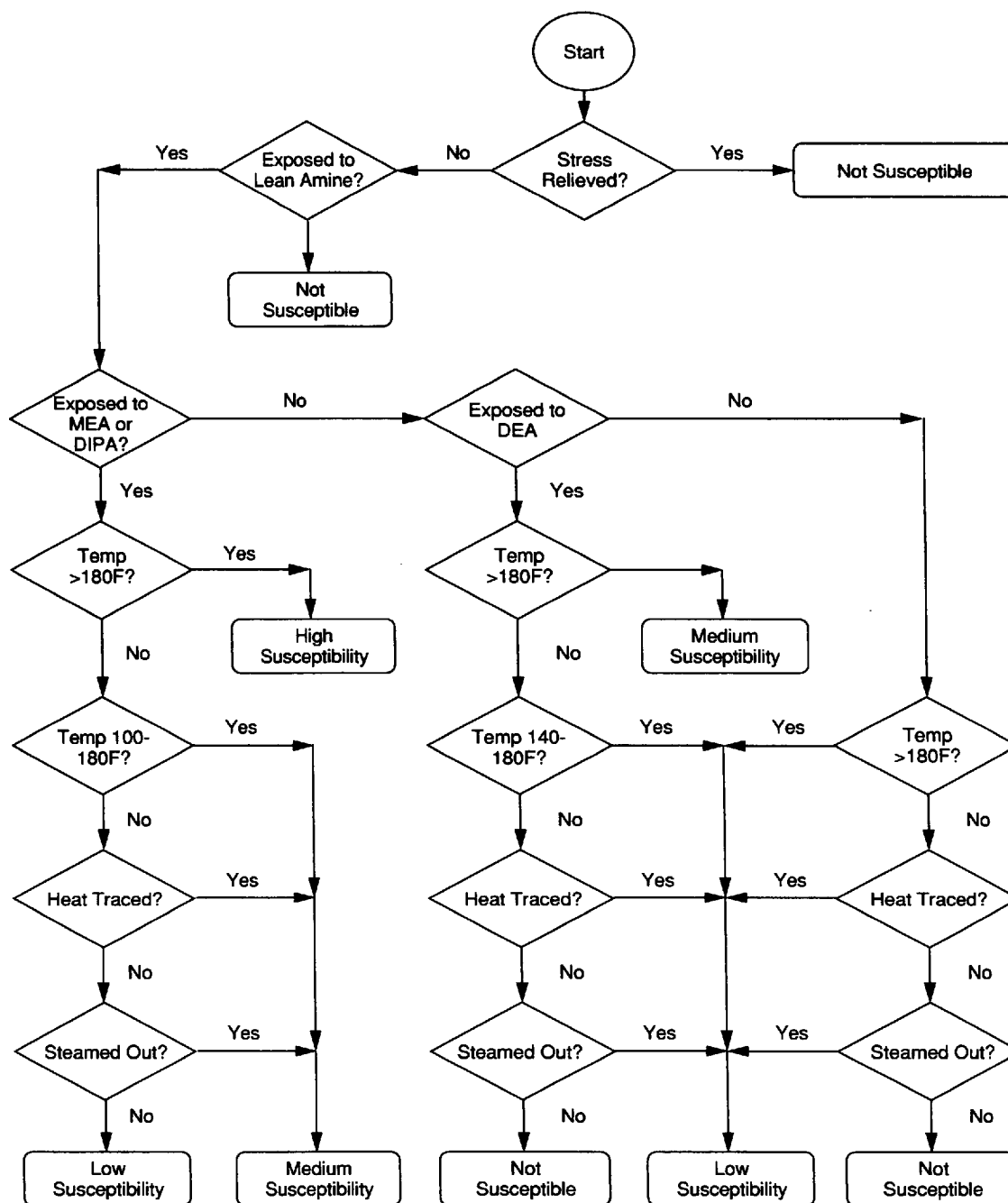


Figure H-4—Determination of Susceptibility to Amine Cracking

Table H-8—Basic Data Required for Analysis of Sulfide Stress Cracking

| Basic Data                          | Comments                                                                                                                                                                                                                                                                                                                                  |
|-------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Presence of Water<br>(Yes or No)    | Determine whether free water is present in the equipment/piping. Consider not only normal operating conditions, but also startup, shutdown, process upsets, etc.                                                                                                                                                                          |
| H <sub>2</sub> S Content of Water   | Determine the H <sub>2</sub> S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore (Reference 2).                                                                                                                                                       |
| pH of Water                         | Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.                                                                                                                                                                                         |
| Presence of Cyanides<br>(Yes or No) | Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also startup and shutdown conditions.                                                                                                                                                                        |
| Max Brinell Hardness                | Determine the maximum Brinell hardness actually measured at the weldments of the steel equipment/piping. Report readings actually taken as Brinell, not converted from finer techniques (e.g., Vickers, Knoop, etc.) If actual readings are not available, use the maximum allowable hardness permitted by the fabrication specification. |
| PWHT of Weldments<br>(Yes or No)    | Determine whether all the weldments of the equipment/piping have been properly postweld heat treated after welding.                                                                                                                                                                                                                       |

Table H-9—Environmental Severity

| pH of Water | H <sub>2</sub> S Content of Water |                 |                       |                   |
|-------------|-----------------------------------|-----------------|-----------------------|-------------------|
|             | < 50 ppm                          | 50 to 1,000 ppm | 1,000 to 10,000 ppm   | > 10,000 ppm      |
| < 5.5       | Low                               | Moderate        | High                  | High              |
| 5.5 to 7.5  | Low                               | Low             | Low                   | Moderate          |
| 7.6 to 8.3  | Low                               | Moderate        | Moderate              | Moderate          |
| 8.4 to 8.9  | Low                               | Moderate        | Moderate <sup>a</sup> | High <sup>a</sup> |
| > 9.0       | Low                               | Moderate        | High <sup>a</sup>     | High <sup>a</sup> |

<sup>a</sup>If cyanides are present, increase the susceptibility to SSC one category for pH > 8.3 and H<sub>2</sub>S concentrations greater than 1,000 ppm.

Table H-10—Susceptibility to SSC

| Environmental Severity | As-welded<br>Max Brinell Hardness <sup>a</sup> |         |        | PWHT<br>Max Brinell Hardness <sup>a</sup> |         |        |
|------------------------|------------------------------------------------|---------|--------|-------------------------------------------|---------|--------|
|                        | < 200                                          | 200-237 | > 237  | < 200                                     | 200-237 | > 237  |
| High                   | Low                                            | Medium  | High   | Not                                       | Low     | Medium |
| Moderate               | Low                                            | Medium  | High   | Not                                       | Not     | Low    |
| Low                    | Low                                            | Low     | Medium | Not                                       | Not     | Not    |

<sup>a</sup> Actually tested as Brinell, not converted from finer techniques, e.g. Vickers, Knoop, etc.

2. R. R. Petrie and E. M. Moore, Jr., "Determining the Suitability of Existing Pipelines and Producing Facilities for Wet Sour Service," *Materials Performance* 28, 6 (June 1989), pp. 59-65.

3. *Review of Published Literature on Wet H<sub>2</sub>S Cracking of Steels Through 1989*, NACE Publication 8X294

4. *Stress Corrosion Cracking and Hydrogen Embrittlement of Iron Base Alloys*, NACE-5, Edited by R. W.

Staehle, et. al., NACE International, Houston, TX, 1977, pp. 541-559.

5. C. M. Hudgins, et. al., "Hydrogen Sulfide Cracking of Carbon and Alloy Steels," *Corrosion*, Vol. 22, pp. 238-251.

6. *Guidelines for Detection, Repair, and Mitigation of Existing Petroleum Refinery Pressure Vessels in Wet H<sub>2</sub>S Environments*, NACE Standard RP0296-96.

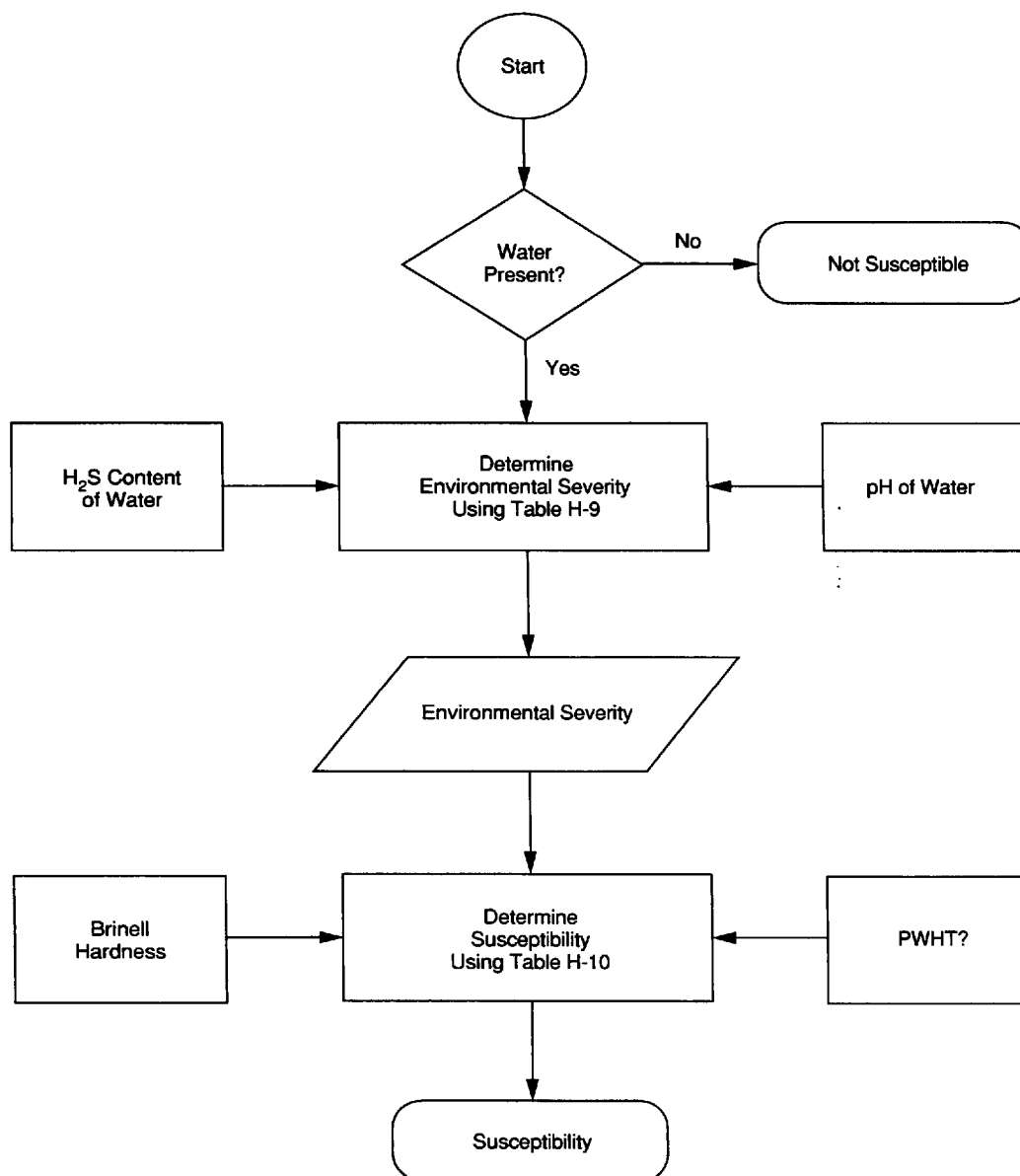


Figure H-5—Determination of Susceptibility of Sulfide Stress Cracking

## H.8 Hydrogen-Induced Cracking and Stress-Oriented Hydrogen Induced Cracking in Hydrogen Sulfide Services (HIC/SOHIC-H<sub>2</sub>S)

### H.8.1 DESCRIPTION OF DAMAGE

Hydrogen-induced cracking is defined as stepwise internal cracks that connect adjacent hydrogen blisters on different planes in the metal, or to the metal surface. No externally applied stress is needed for the formation of HIC. The driving force for the cracking is high stresses at the circumference of the hydrogen blisters caused by buildup of internal pressure in the blisters. Interactions between these high stress fields tend to cause cracks to develop that link blisters on different planes in the steel.

The buildup of pressure in the blisters is related to the hydrogen permeation flux in the steel. The source of the hydrogen in the steel is the corrosion reaction with wet hydrogen sulfide. Water must be present for this corrosion reactor to occur, and the resultant hydrogen flux is primarily associated with two environmental parameters—pH and H<sub>2</sub>S content of the water. Typically, the hydrogen flux in steels has been found to be lowest in near neutral pH solutions, with increasing flux at both lower and higher pH values. Corrosion at low pH values is caused by H<sub>2</sub>S, where as corrosion at high pH values is caused by high concentrations of the bisulfide ion. Presence of cyanides at elevated pH can further aggravate the hydrogen penetration into the steel. Hydrogen permeation is known to increase with H<sub>2</sub>S content, e.g. H<sub>2</sub>S partial pressure in the gas phase or H<sub>2</sub>S content of the water phase. The presence of as little as 50 ppm of H<sub>2</sub>S in the water has been sufficient to cause HIC.

Hydrogen blisters are planar hydrogen-filled cavities formed at discontinuities in the steel (e.g. voids, inclusions, laminations, sulfide inclusions). Blisters most often occur in rolled plate steels, especially those with a banded microstructure resulting from elongated sulfide inclusions. Susceptibility to hydrogen blistering, and therefore HIC is primarily related to the quality of the plate steel, i.e., the number, size and shape of the discontinuities. In this regard, the sulfur content of the steel is a key material parameter. Reducing the sulfur content of the steel reduces the susceptibility to blistering and HIC. Additions of calcium which controls sulfide inclusion shape control is generally beneficial.

SOHIC is defined as a stacked array of small blisters joined by hydrogen-induced cracking that is aligned in the through-thickness direction of the steel as a result of high localized tensile stresses. SOHIC is a special form of HIC which usually occurs in the base metal, adjacent to the heat-affected zone of a weld, where stresses are highest due to the additive effect of applied stress (from internal pressure) and the residual stresses from welding. As with HIC, plate steel quality is a key parameter for SOHIC susceptibility. In addition, reduction of residual stresses by PWHT can reduce, but may not eliminate, the occurrence and severity of SOHIC. The level of applied stress also influences the occurrence and severity of SOHIC. Although HIC/SOHIC is much more prominent in plate steel fabrications, it has been observed to a limited extent in steel pipe fabrications, usually in the more severe hydrogen charging environments.

### H.8.2 BASIC DATA

The data listed in Table H-11 are required to estimate susceptibility of carbon steel equipment and piping to HIC/SOHIC. If

Table H-11—Basic Data Required for Analysis of HIC/SOHIC-H<sub>2</sub>S

| Basic Data                            | Comments                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
|---------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Presence of Water<br>(Yes or No)      | Determine whether free water is present in the equipment/piping. Consider not only normal operating conditions, but also startup, shutdown, process upsets, etc.                                                                                                                                                                                                                                                                                                                                                                      |
| H <sub>2</sub> S Content of Water     | Determine the H <sub>2</sub> S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore                                                                                                                                                                                                                                                                                                                                                                  |
| pH of Water                           | Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.                                                                                                                                                                                                                                                                                                                                                                                     |
| Presence of Cyanides<br>(Yes or No)   | Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also startup and shutdown conditions.                                                                                                                                                                                                                                                                                                                                                                    |
| Sulfur Content of Plate Steel         | Determine the sulfur content of the steel used to fabricate the equipment/piping. This information should be available on MTR's in equipment files. If not available, it can be estimated from the ASTM or ASME specification of the steel listed on the U-1 form in consultation with materials engineer.                                                                                                                                                                                                                            |
| Steel Product Form<br>(Plate or Pipe) | Determine what product form of steel was used to fabricate the equipment/piping. Most equipment is fabricated from rolled and welded steel plates (e.g. A285, A515, A516, etc.), but some small-diameter equipment is fabricated from steel pipe and piping components. Most small-diameter piping is fabricated from steel pipe (e.g. A106, A53, API 5L, etc.) and piping components (e.g. A105, A234, etc.), but most large diameter piping (above approximately 16 in. diameter) is fabricated from rolled and welded plate steel. |
| PWHT of Weldments<br>(Yes or No)      | Determine whether all the weldments of the equipment/piping have been properly postweld heat treated after welding.                                                                                                                                                                                                                                                                                                                                                                                                                   |



exact process data are not known, contact a knowledgeable process engineer to obtain the best estimates. If the sulfur content of the plate steel is not known, contact a knowledgeable materials engineer to obtain an estimate of steel quality.

### H.8.3 DETERMINATION OF ENVIRONMENTAL SEVERITY

If there is no water present, then the equipment/piping is considered not susceptible to HIC/SOHIC. If there is water present, then the basic data from Table H-12 on the H<sub>2</sub>S content of the water and its pH should be used to estimate the environmental severity (potential level of hydrogen flux) using Table H-13.

\*If cyanides are present, increase the susceptibility to SCC one category for pH > 8.3 and H<sub>2</sub>S concentrations greater than 1,000 ppm.

### H.8.4 DETERMINATION OF SUSCEPTIBILITY TO HIC/SOHIC

For equipment and large-diameter piping fabricated from rolled and welded plate steel, the environmental severity determined in Table H-12 and the basic data from Table H-11 on the sulfur content of the plate steel and postweld heat treatment, should be used to determine the susceptibility to HIC/SOHIC using Table H-13. Small-diameter equipment and piping fabricated from steel pipe and piping components should be considered to have a low susceptibility to HIC/SOHIC unless it has not been postweld heat treated and is exposed to a high severity environment, in which case it

should be considered to have a medium susceptibility. A flow chart of the steps required to determine the susceptibility to HIC/SOHIC is presented in Figure H-6.

#### References

1. R. R. Petrie and E. M. Moore, Jr., "Determining the Suitability of Existing Pipelines and Producing Facilities for Wet Sour Service," *Materials Performance* 28, 6 (June 1989), pp. 59-65.
2. R. D. Merrick, "Refinery Experiences with Cracking in Wet H<sub>2</sub>S Environments," *Materials Performance* 27, 1 (January 1988), pp. 30.
3. R. D. Merrick and M.L. Bullen, "Prevention of Cracking in Wet H<sub>2</sub>S Environments," NACE Corrosion/89, paper no. 269.
4. *Materials and Fabrication Practices for New Pressure Vessels Used in Wet H<sub>2</sub>S Refinery Service*, NACE Publication 8X194.
5. Review of Published Literature on Wet H<sub>2</sub>S Cracking of Steels Through 1989, NACE Publication 8X294.
6. Research Report on Characterization and Monitoring of Cracking in Wet H<sub>2</sub>S Service, API Publication 939, October 1994.
7. M. S. Cayard and R. D. Kane, "Characterization and Monitoring of Cracking of Steel Equipment in Wet H<sub>2</sub>S Service," NACE Corrosion/95, Paper no. 329.
8. *Guidelines for Detection, Repair, and Mitigation of Existing Petroleum Refinery Pressure Vessels in Wet H<sub>2</sub>S Environments*, NACE Standard RP0296-96.

Table H-12—Environmental Severity

| pH of Water | H <sub>2</sub> S Content of Water |                 |                       |                   |
|-------------|-----------------------------------|-----------------|-----------------------|-------------------|
|             | < 50 ppm                          | 50 to 1,000 ppm | 1,000 to 10,000 ppm   | > 10,000 ppm      |
| < 5.5       | Low                               | Moderate        | High                  | High              |
| 5.5 to 7.5  | Low                               | Low             | Low                   | Moderate          |
| 7.6 to 8.3  | Low                               | Moderate        | Moderate              | Moderate          |
| 8.4 to 8.9  | Low                               | Moderate        | Moderate <sup>a</sup> | High <sup>a</sup> |
| > 9.0       | Low                               | Moderate        | High <sup>a</sup>     | High <sup>a</sup> |

<sup>a</sup>If cyanides are present, increase the susceptibility of SCC one category for pH > 8.3 and H<sub>2</sub>S concentrations greater than 1,000 ppm.

Table H-13—Susceptibility to HIC/SOHIC

| Environmental Severity | High Sulfur Steel <sup>a</sup><br>> 0.01% S |        | Low Sulfur Steel <sup>b</sup><br>0.002 to 0.01% S |        | Ultra Low Sulfur <sup>c</sup><br>< 0.002% S |      |
|------------------------|---------------------------------------------|--------|---------------------------------------------------|--------|---------------------------------------------|------|
|                        | As-Welded                                   | PWHT   | As-Welded                                         | PWHT   | As-Welded                                   | PWHT |
| High                   | High                                        | High   | High                                              | Medium | Medium                                      | Low  |
| Moderate               | High                                        | Medium | Medium                                            | Low    | Low                                         | Low  |
| Low                    | Medium                                      | Low    | Low                                               | Low    | Not                                         | Not  |

<sup>a</sup>Typically includes A 70, A 201, A 212, A 285, A 515, and most A 516 before about 1990.

<sup>b</sup>Typically includes early generations of HIC-resistant A 516 in 1980s, with Ca additions.

<sup>c</sup>Typically includes later generations of HIC-resistant A 516 in 1990s.

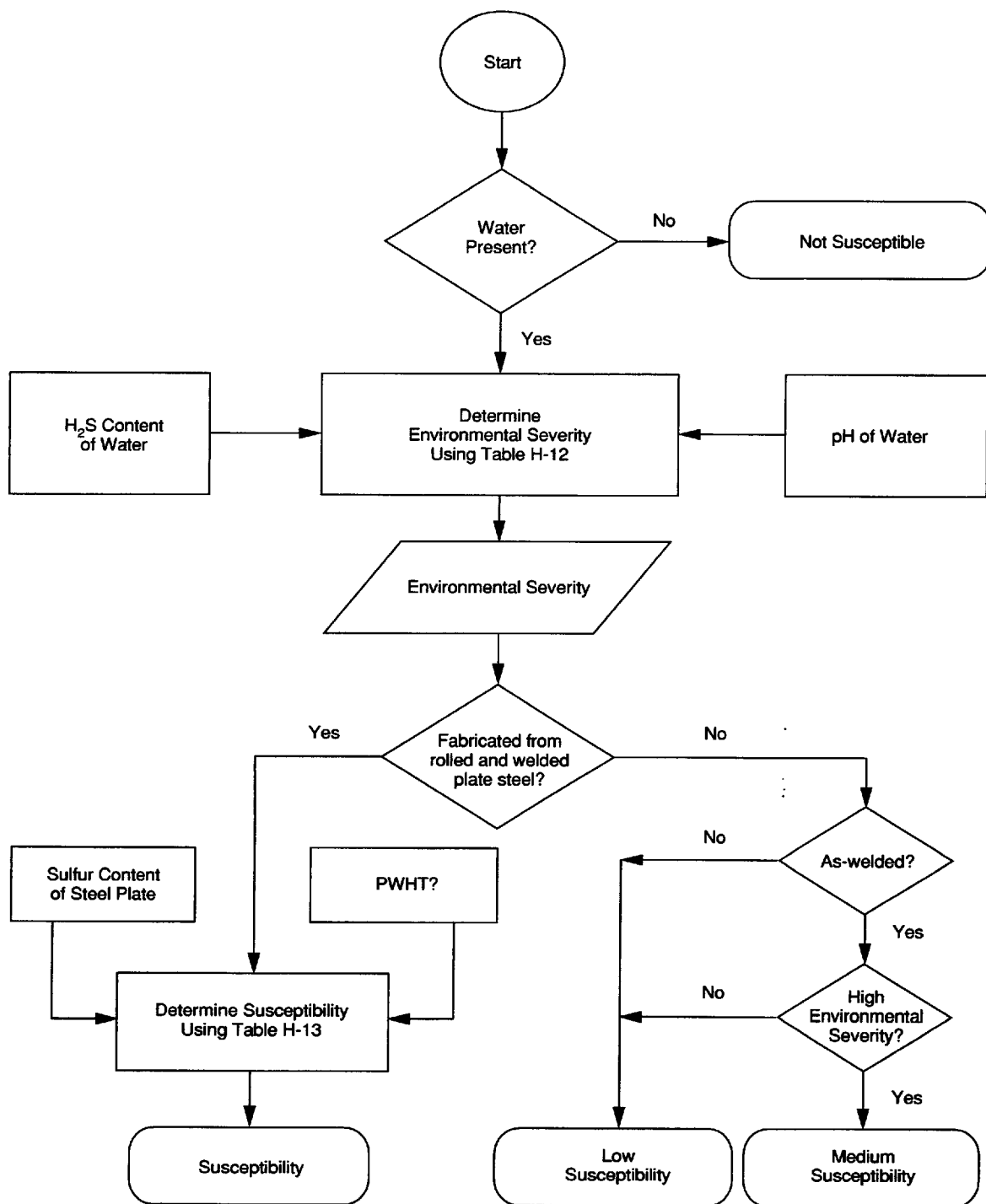


Figure H-6—Determination of Susceptibility to HIC/SOHIC

## H.9 Carbonate Cracking

### H.9.1 DESCRIPTION OF DAMAGE

Carbonate cracking is a common term applied to cracking of a metal under the combined action of tensile stress and corrosion in the presence of an alkaline sour water containing moderate to high concentrations of carbonate. The cracking is predominantly intergranular in nature, and typically occurs in as-welded carbon steel fabrications as a network of very fine, oxide-filled cracks. Carbonate cracking typically propagates parallel to the weld in adjacent base metal, but can also occur in the weld deposit or heat-affected zones. The pattern of cracking observed on the steel surface is sometimes described as a spider web of small cracks, which often initiate at or interconnect with weld-related flaws that serve as local stress raisers.

Carbonate cracking has been most prevalent in the catalytic cracking unit main fractionator overhead condensing and reflux system, the downstream wet gas compression system, and the sour water systems emanating from these areas. Assuming the presence of a sour water phase, three key parameters are used to assess the susceptibility of steel fabrications to carbonate cracking. They are the pH of the sour water, carbonate concentration of the sour water, and level of tensile stress.

Studies have concluded that the cracking occurs in a narrow range of electrochemical potential, which is very dependent upon the sour water composition. Presence of moderate to high levels of carbonates in an alkaline sour water often produces an electrochemical potential of steel which is in this narrow range where carbonate cracking is likely to occur. Another common contaminant in these sour waters, cyanides, has been shown to influence cracking susceptibility. Despite this mechanistic understanding, the electrochemical potential of in-service equipment and piping may not be readily available. Therefore, pH and carbonate concentration of the sour water are judged to be the key environmental parameters

influencing the susceptibility of steel fabrications to carbonate cracking. Based on a survey of many units reported in Reference 2, cracking susceptibility increases with increasing pH and carbonate concentration.

With regard to the level of tensile stress, as-welded or as-bent carbon steel fabrications are susceptible to carbonate cracking because of the high level of residual stress remaining after fabrication by these methods. Application of a post-fabrication stress-relieving heat treatment (e.g. postweld heat treatment) is a proven method of preventing carbonate cracking. A heat treatment of about 1150°F for one hour per inch of thickness (one hour minimum) is considered an effective stress-relieving heat treatment to prevent carbonate cracking of carbon steel.

### H.9.2 BASIC DATA

The data listed in Table H-14 are required to determine the susceptibility of carbon steel equipment and piping to carbonate cracking. If exact process data are not known, contact a knowledgeable process engineer to obtain the best estimates.

### H.9.3 DETERMINATION OF SUSCEPTIBILITY TO CARBONATE CRACKING

If the equipment/piping is properly stress relieved, then it is considered not susceptible to carbonate cracking. If there is no free water present, or if the water phase present contains less than 50 ppm H<sub>2</sub>S, the equipment/piping is considered Not Susceptible. If the equipment/piping contains a water phase with 50 ppm or greater H<sub>2</sub>S at a pH of 7.6 or greater, then the equipment/piping is considered susceptible. Using the basic data from Table H-14 on pH and carbonate concentration of the water phase, the susceptibility to carbonate cracking should be determined using Table H-15. A flow chart of the steps required to determine the susceptibility to carbonate cracking is presented in Figure H-7.

Table H-14—Basic Data Required for Analysis of Carbonate Cracking

| Basic Data                                                              | Comments                                                                                                                                                                                                               |
|-------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Presence of Water<br>(Yes or No)                                        | Determine whether free water is present in the equipment/piping. Consider not only normal operating conditions, but also startup, shutdown, process upsets, etc.                                                       |
| Presence of 50 ppm or more H <sub>2</sub> S in the Water<br>(Yes or No) | Determine whether 50 ppm or more H <sub>2</sub> S is present in the water phase in this equipment/piping. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer. |
| CO <sub>3</sub> = Concentration in Water                                | Determine the carbonate concentration of the water phase present in this equipment/piping. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.                |
| pH of Water                                                             | Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.                                                                      |
| Stress Relieved?<br>(Yes or No)                                         | Determine whether the equipment/piping has been properly stress relieved after welding and cold forming.                                                                                                               |

Table H-15—Susceptibility to Carbonate Cracking

| pH of Water | CO <sub>3</sub> = Concentration in Water |               |                |            |
|-------------|------------------------------------------|---------------|----------------|------------|
|             | < 100 ppm                                | 100 – 500 ppm | 500 – 1000 ppm | > 1000 ppm |
| 7.6 to 8.3  | Low                                      | Low           | Low            | Medium     |
| 8.4 to 8.9  | Low                                      | Low           | Medium         | High       |
| = 9.0       | Low                                      | Medium        | High           | High       |

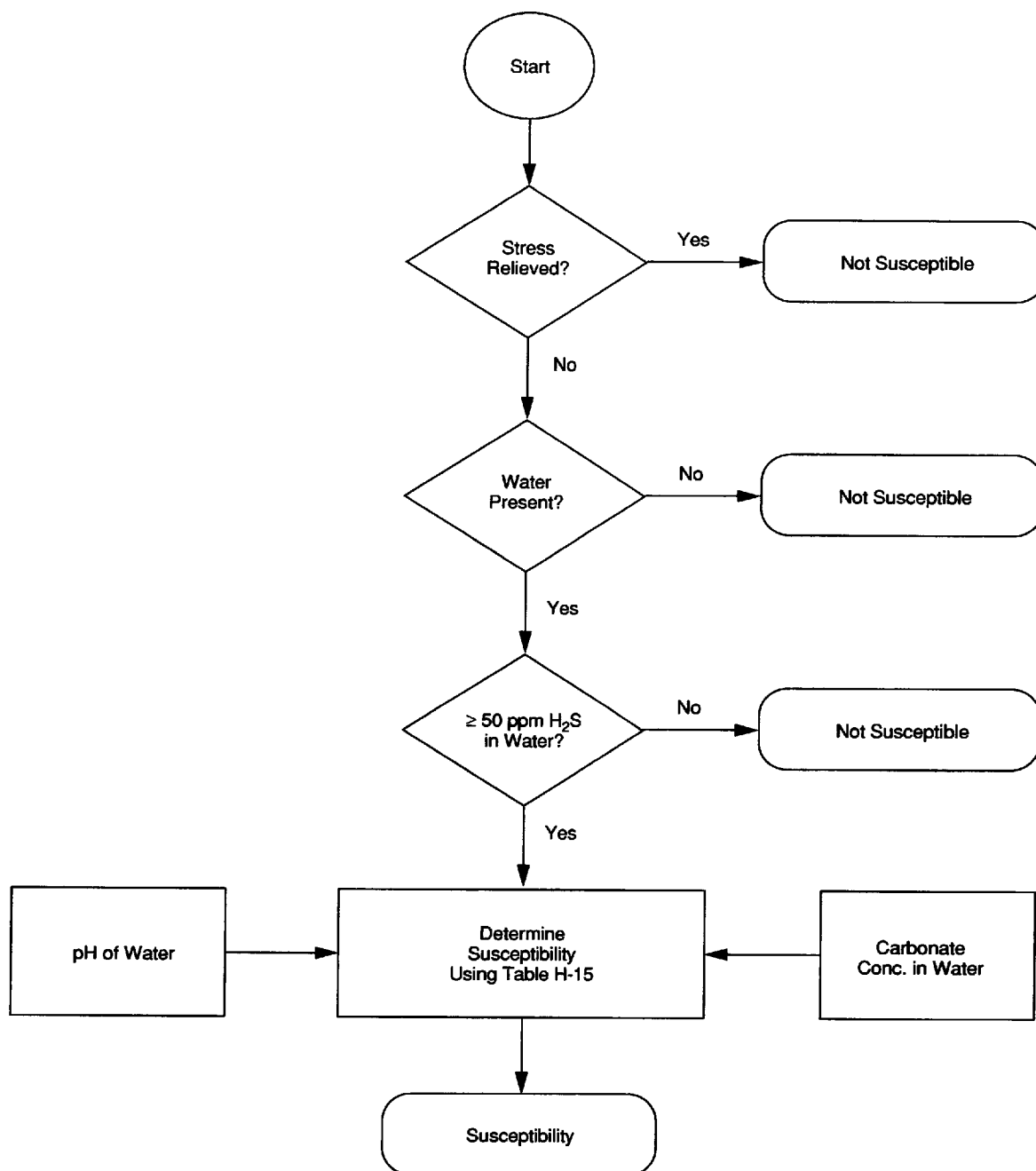


Figure H-7—Determination of Susceptibility to Carbonate Cracking

## References

1. R. D. Merrick, "Refinery Experiences with Cracking in Wet H<sub>2</sub>S Environments," *Materials Performance* 27, 1 (1988), pp. 30-36.
2. J. H. Kmetz and D. J. Truax, "Carbonate Stress Corrosion Cracking of Carbon Steel in Refinery FCC Main Fractionator Overhead Systems," NACE Paper #206, CORROSION/90.
3. H. U. Schutt, "Intergranular Wet Hydrogen Sulfide Cracking," NACE Paper #454, Corrosion/92 (see also "Stress Corrosion Cracking of Carbon Steel in Amine Systems," NACE paper #187, Corrosion/87) (see also *Materials Performance* 32, 11 (1993), pp. 55-60).

## H.10 Polythionic Acid Cracking (PTA)

### H.10.1 DESCRIPTION OF DAMAGE

Polythionic acid (PTA) and sulfurous acid are major considerations in the petroleum-refining industry, particularly in catalytic cracking, desulfurizer, hydrocracker and catalytic reforming processes. These complex acids typically form in sulfide containing deposits during shutdown (or ambient) conditions when the equipment and/or piping are exposed to air and moisture. The acid environment, combined with susceptible materials of construction in the sensitized or as-welded condition, results in rapid intergranular corrosion and cracking. Preventive measures to reduce or eliminate PTA include flushing the equipment with alkaline or soda ash solution to neutralize sulfides immediately after shutdown and exposure to air or purging with dry nitrogen during the shutdown to prevent air exposure, according to recommended practices established by NACE (RP0170).

PTA and sulfurous acid will cause SCC in sensitized austenitic stainless steels and nickel-base alloys. Cracking is

always intergranular and requires relatively low tensile stresses for initiation and propagation. As-welded, regular and high carbon grade stainless steels, such as types 304/304H and 316/316H, are particularly susceptible to SCC in the weld HAZ. Low-carbon (< 0.03% C) are less susceptible at temperatures less than 800°F. Chemically stabilized stainless steel grades, such as types 321 and 347 are less susceptible to PTA, particularly if they are thermally stabilized. Susceptibility of alloys and chemically or thermally stabilized materials to PTA can be determined by laboratory corrosion testing according to ASTM G35.

### H.10.2 BASIC DATA

The data listed in H-16 are required to determine the susceptibility of equipment or piping to PTA. If exact process data is not known, contact a knowledgeable process engineer to obtain the best estimates.

### H.10.3 DETERMINE SUSCEPTIBILITY TO PTA

If the process temperature is less than or equal to 800 °F, use Table H-17 to determine susceptibility. If the process temperature is greater than 800°F, use Table H-18 to determine susceptibility. A flow chart of the steps required to determine the susceptibility to PTA is presented in Figure H-8.

## References

1. *Metals Handbook*, Ninth Edition, ASM International, Metals Park, Ohio 44073, Volume 13 *Corrosion*, pp. 327.
2. D. R. McIntyre and C. P. Dillon, *Guidelines for Preventing Stress Corrosion Cracking in the Chemical Process Industries*, Publication 15, Materials Technology Institute of the Chemical Process Industries, 1985, pp. 69.
3. *The Role of Stainless Steels in Petroleum Refining*, American Iron and Steel Institute, 1977, pp. 42-44.

Table H-16—Basic Data Required for Analysis of Polythionic Acid Cracking

| Basic Data                                                                                                           | Comments                                                                                                                                                                                                                                  |
|----------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Material of Construction                                                                                             | Determine the material of construction of the equipment/piping.                                                                                                                                                                           |
| Thermal History<br>(Solution Annealed, Stabilized before welding,<br>Stabilized after welding)                       | Determine the thermal history of the material. Consider especially whether thermal stabilization heat treatment was performed after all welding.                                                                                          |
| Maximum Operating Temperature (°F)                                                                                   | Determine the maximum operating temperature of the equipment/piping. Consider any high temperature exposure such as during decoking.                                                                                                      |
| Presence of Sulfides,<br>Moisture and Oxygen:<br>During Operation?<br>(Yes or No)<br>During Shutdown?<br>(Yes or No) | Determine whether these constituents are present in the equipment/piping. If uncertain, consult with a process engineer. Consider whether high temperature equipment/piping in sulfidic service is opened to environment during shutdown. |
| Downtime Protection Used?<br>(Yes or No)                                                                             | Determine whether downtime protection for PTA has been provided per NACE RP0170. This may include soda ash washing, nitrogen blanketing, or dehumidification.                                                                             |

Table H-17—Susceptibility to PTA—Operating Temperatures = 800°F

|                                                                       | Solution Annealed (default) | Stabilized Before Welding | Stabilized After Welding |
|-----------------------------------------------------------------------|-----------------------------|---------------------------|--------------------------|
| All regular 300 series Stainless Steels and Alloys 600 and 800        | Medium                      | —                         | —                        |
| H Grade 300 series SS                                                 | High                        | —                         | —                        |
| L Grade 300 series SS Low                                             | Low                         | —                         | —                        |
| 321 Stainless Steel                                                   | Medium                      | Medium                    | Low                      |
| 347 Stainless Steel, Alloy 20, Alloy 625, All austenitic weld overlay | Low                         | Low                       | Low                      |

If the process operating temperature is < 800 °F, sensitization is present in the as-welded condition only. If the process operating temperature > 800 °F, sensitization can occur during operation.

Table H-18—Susceptibility to PTA—Operating Temperatures &gt; 800°F

|                                                                       | Solution Annealed (default) | Stabilized Before Welding | Stabilized After Welding |
|-----------------------------------------------------------------------|-----------------------------|---------------------------|--------------------------|
| All regular 300 series Stainless Steels and Alloys 600 and 800        | High                        | —                         | —                        |
| H Grade 300 series SS                                                 | High                        | —                         | —                        |
| L Grade 300 series SS                                                 | Medium                      | —                         | —                        |
| 321 Stainless Steel                                                   | High                        | High                      | Low                      |
| 347 Stainless Steel, Alloy 20, Alloy 625, All austenitic weld overlay | Medium                      | Low                       | Low                      |

4. *Protection of Austenitic Stainless Steels and Other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking During Shutdown of Refinery Equipment*, NACE International Recommended Practice RP0170-93, NACE International, Houston, TX.

5. D. V. Beggs, and R. W. Howe, "Effects of Welding and Thermal Stabilization on the Sensitization and Polythionic Acid Stress Corrosion Cracking of Heat and Corrosion-Resistant Alloys," NACE International Corrosion/93 Paper 541, NACE International, Houston, TX.

6. L. Scharfstein, "The Effect of Heat Treatments in the Prevention of Intergranular Corrosion Failures of AISI 321 Stainless Steel," *Materials Performance*, September 1983, pp. 22–24.

7. E. Lendvai-Linter, "Stainless Steel Weld Overlay Resistance to Polythionic acid Attack," *Materials Performance*, Volume 18, No. 3, 1979, pp. 9.

8. K. Tamaki, S. Nakano, and M. Kimura, "Application of CrNi Stainless Steel Weld Metals to Polythionic Acid

Environments," *Materials Performance*, August 1987, pp. 9–13.

9. C. H. Samans, "Stress Corrosion Cracking Susceptibility of Stainless Steels and Nickel-Base Alloys in Polythionic Acids and Acid Copper Sulfate Solution," *Corrosion*, Volume 20, No. 8, August 1964, pp. 256–262.

10. R. L. Piehl, "Stress Corrosion Cracking by Sulfur Acids," *Proceedings of API Division of Refining*, Volume 44 (III), 1964, pp. 189–197.

11. S. Ahmad, M. L. Mehta, S. K. Saraf, and I. P. Saraswat, "Stress Corrosion Cracking of Sensitized 304 Austenitic Stainless Steel in Sulfurous Acid," *Corrosion*, Volume 37, No. 7, July 1981, pp. 412–415.

12. S. Ahmad, M. L. Mehta, S. K. Saraf, and I. P. Saraswat, "Stress Corrosion Cracking of Sensitized 304 Austenitic Stainless Steel in Petroleum Refinery Environment," *Corrosion*, Volume 38, No. 6, June 1982, p. 347–353.

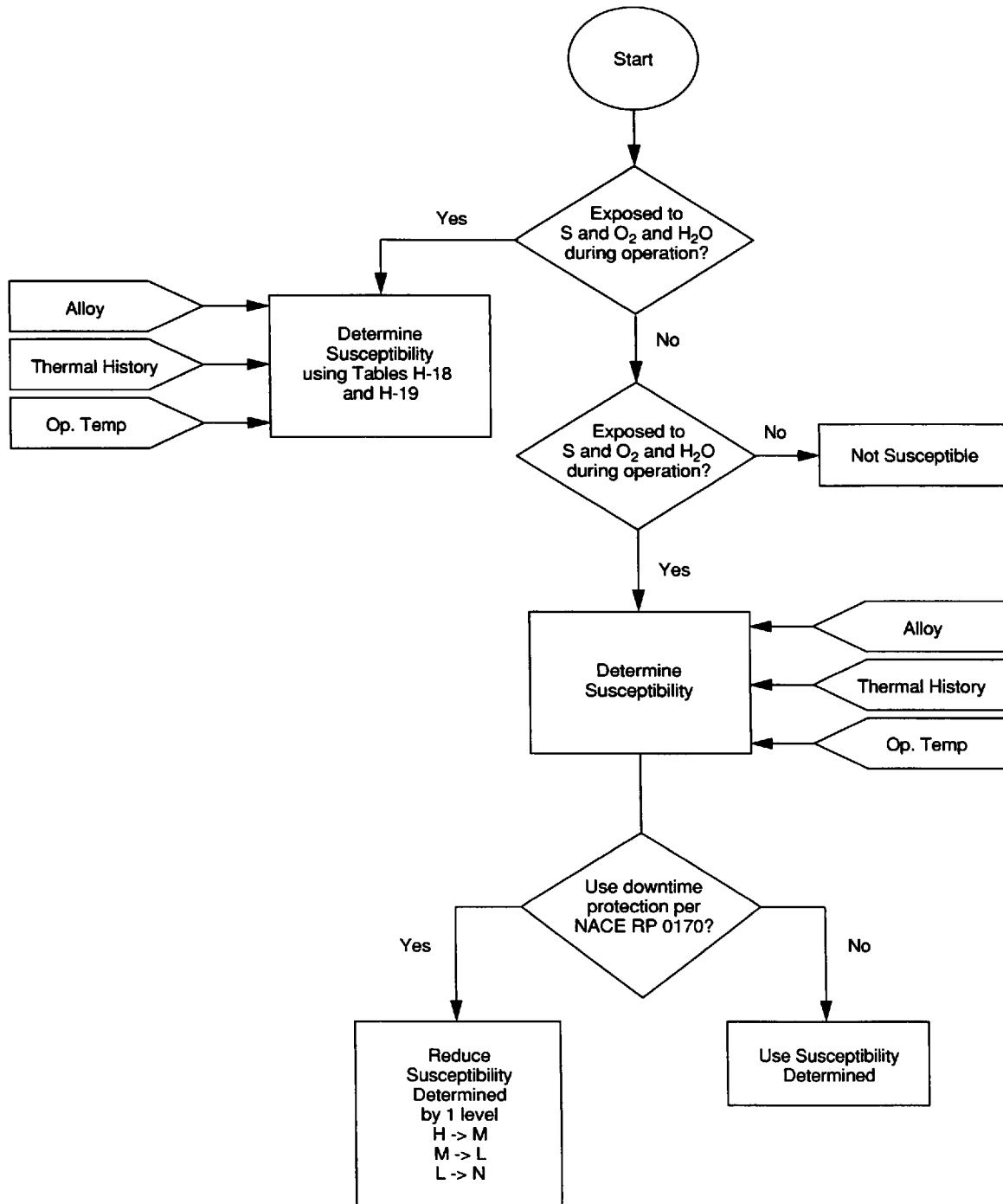


Figure H-8—Determination of Susceptibility to Polythionic Acid Cracking (PTA)

## H.11 Chloride Stress Corrosion Cracking (CISCC)

### H.11.1 DESCRIPTION OF DAMAGE

Chloride stress corrosion cracking (CISCC) of austenitic stainless steels can occur in a chloride containing aqueous environment. The susceptibility to CISCC is dependent on the concentration of the chloride ions, the temperature, and other factors outlined in the basic data Table H-19. It should be emphasized that the chloride concentration in water within wetting and drying conditions can be higher than the concentration measured in the bulk solution due to partial water vaporization. Such vaporization can increase CISCC susceptibility. CISCC is more likely to occur at metal temperatures above 150°F. Examples of common sources of chlorides in a refinery are as follows:

- Chloride salts from crude oil, produced water, and ballast water.
- Water condensed from process stream (process water).
- Boiler feedwater and stripping system.
- Catalyst.
- Insulation.
- Residue from hydrotest water and other manufacturing operations.
- Fumes for chemicals containing either organic or inorganic chlorides.

CISCC may occur during service or shutdown periods, if chloride containing solutions are present, especially at temperatures above 150°F. CISCC can occur internally (for example, by wash-up water or fire water).

Chloride SCC is typically transgranular and highly branched. The greatest susceptibility to CISCC is exhibited by austenitic stainless steels with a nickel content of 8% (e.g. 300 series SS, 304, 316, etc.). Greater resistance is generally shown by alloys of either lower or higher nickel contents. Duplex stainless steels with low nickel contents are generally immune to CISCC, as are alloys with greater than 42% nickel.

### H.11.2 BASIC DATA

The data listed in Table H-19 is required to determine the susceptibility of austenitic stainless steel equipment and piping to CISCC. If exact data is not known, contact a knowledgeable process engineer to obtain the estimates.

### H.11.3 DETERMINATION OF SUSCEPTIBILITY TO CISCC

Using basic data from Table H-19, determine the process side susceptibility to CISCC from Table H-20 or H-21. Then enter the decision tree in Figure H-9 to determine the susceptibility to CISCC.

Table H-19—Basic Data Required for Analysis of CISCC

| Basic Data                               | Comments                                                                                                                                                                                                                                                                                 |
|------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Cl- Concentration of Process Water (ppm) | Determine the bulk Cl- concentration of the water phase. If unknown, default value for ppm is >1000. Consider Cl- content of any water present in system (i.e. hydrotest, boiler feed, steam) Also, consider the possibility of concentration of Cl- by evaporation or upset conditions. |
| Operating Temperature (°F)               | Determine the highest operating temperature expected during operation (consider normal and non-normal operating conditions).                                                                                                                                                             |
| pH of Process Water                      | Determine pH of the process water. High pH solutions with high chlorides generally are not as susceptible to cracking as low pH solution with chlorides. Default is pH = 10.                                                                                                             |

\* Steam traced lines are in the 130°F to 200°F range unless the operating temperature is higher than 200°F.

Table H-20—Process Side Susceptibility to CISCC (for pH ≤ 10)

| Temperature<br>(°F) | Chloride ion (ppm) |        |          |        |
|---------------------|--------------------|--------|----------|--------|
|                     | 1-10               | 11-100 | 101-1000 | > 1000 |
| 100-150             | Low                | Medium | Medium   | High   |
| 151-200             | Medium             | Medium | High     | High   |
| 201-300             | Medium             | High   | High     | High   |

Table H-21—Process Side Susceptibility to CISCC (for pH > 10)

| Temperature<br>(°F) | Chloride ion (ppm) |        |          |        |
|---------------------|--------------------|--------|----------|--------|
|                     | 1-10               | 11-100 | 101-1000 | >1000  |
| <200                | Low                | Low    | Low      | Low    |
| 201-300             | Low                | Low    | Low      | Medium |



## References

1. D. R. McIntyre and C. P. Dillon, *Guideline for Preventing Stress Corrosion Cracking in the Chemical Process Industries*, Publication 15, Materials Technology Institute of the Chemical Process Industry, 1985.
2. *Stress Corrosion Cracking and Hydrogen Embrittlement of Iron Base Alloys*, Edited by R. W. Staehle, et. al., NACE-5, NACE International, Houston, TX, 1977.
3. "Corrosion in the Petrochemical Industry," Edited by Linda Garverick, *Essential Research*, pages 118-119, ASM International, Materials Park, OH, 1994.

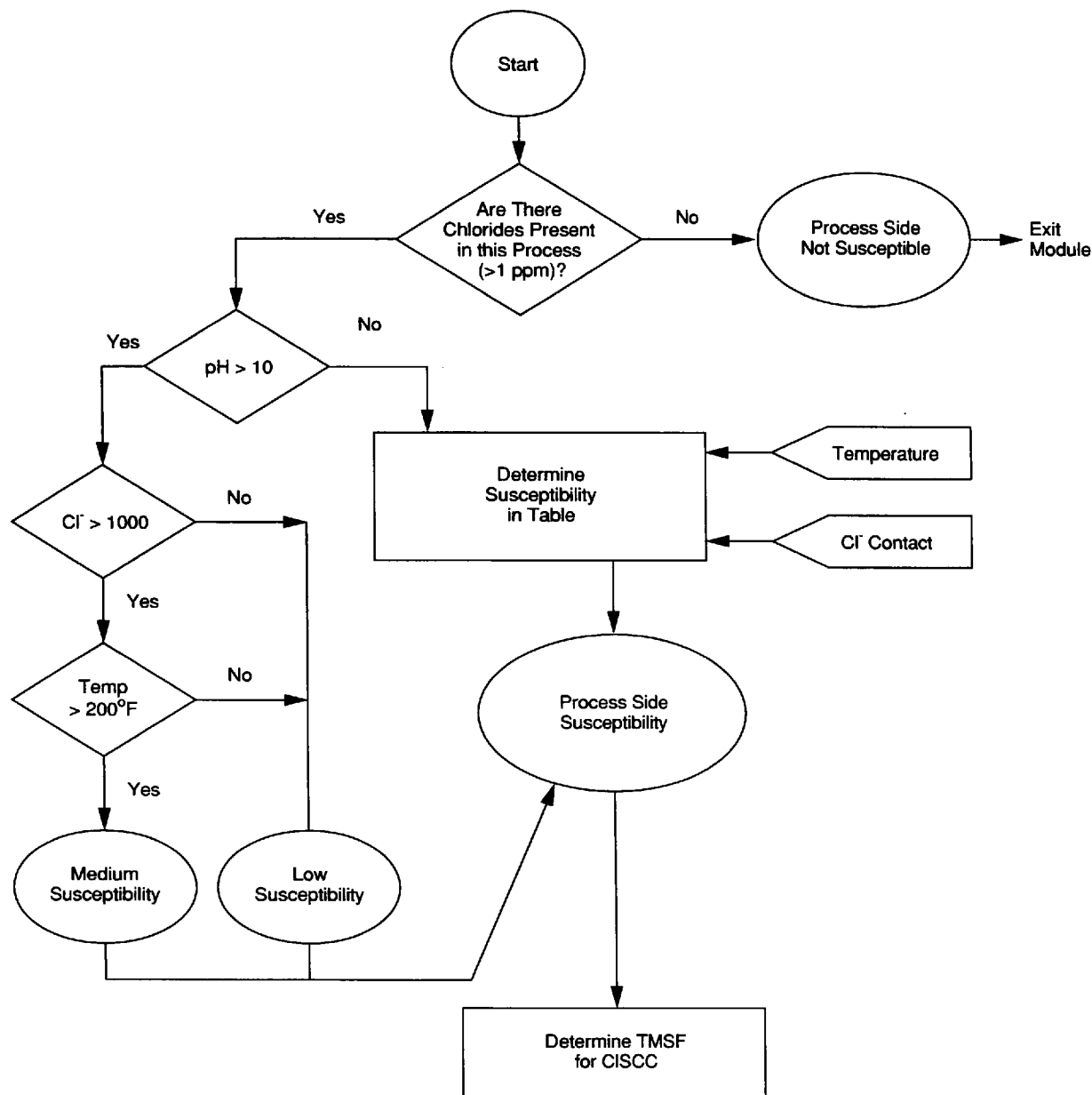


Figure H-9—Determination of Susceptibility to CISC

## H.12 Hydrogen Stress Cracking in Hydrofluoric Acid Service (HSC-HF)

### H.12.1 DESCRIPTION OF DAMAGE

Hydrogen stress cracking (HSC) is defined as cracking of a metal under the combined action of tensile stress and a corrosion mechanism that produces hydrogen which may diffuse into the metal. HSC may result from exposure to hydrogen sulfide (covered in Supplement C—Sulfide Stress Cracking) or from exposure to hydrofluoric acid (HF) as covered in this Supplement. HSC-HF occurs in high-strength (high hardness) steels or in hard weld deposits or hard heat-affected zones of lower-strength steels. In addition, HSC-HF may occur in stressed Alloy 400 if oxygen or other oxidizers are present in the HF.

Concentrated hydrofluoric acid (HF) is used as the acid catalyst in HF alkylation units. The usual HF-in-water concentrations are 96%–99+% and the temperatures are generally below 150°F. Under these conditions a fully killed (deoxidized), low sulfur, clean soft carbon steel is the material of choice for most equipment except where close tolerances are required for operation (i.e., pumps, valves, instruments). Where close tolerances are required and at temperatures over 150°F to approximately 350°F, Alloy 400 is used.

Corrosion in 80% and stronger HF-in-water solutions is equivalent to corrosion in anhydrous hydrofluoric acid (AHF, <200 ppm H<sub>2</sub>O) and reference to corrosion in AHF implies an HF-in-water concentration as low as 80%. HF acid with concentrations lower than 80% HF-in-water are considered aqueous. Both aqueous and anhydrous HF can cause hydrogen embrittlement of hardened carbon and alloy steels. To prevent hydrogen embrittlement in welded steel structures, the

requirements of NACE standard RP0472, *Methods and Controls to Prevent In-Service Cracking of Carbon Steel Welds in Corrosive Petroleum Refining Environments* should be followed. Welds produced by all welding methods should be hardness tested.

Alloy steel fasteners have been a source of many failures in anhydrous HF service. ASTM A193 Grade B7, chromium molybdenum steel bolts are hard and will crack in the presence of HF. Grade B7M, the same steel tempered to a lower hardness of 201–235 Brinell may be a better choice if contact by HF cannot be avoided. However, B7M bolts will also crack if stressed beyond their yield point in an HF environment. Bolt torque may be difficult to control in field flange make-up. In this case, B7 bolts may be specified and replacement of any bolt which may have contacted HF as a result of flange leaks would be required.

### H.12.2 BASIC DATA

Table H-22 lists the basic data required for analysis of susceptibility to HSC-HF. The table also provides comments regarding the data that is required.

### H.12.3 DETERMINATION OF SUSCEPTIBILITY TO HF HSC

If HF is present in any concentration, then the equipment/piping is potentially susceptible to HSC-HF. The basic data from Table H-22 should be used to obtain the susceptibility rating from Table H-23 for carbon steel. A flow chart of the steps required to determine the susceptibility of equipment to HSC-HF is given in Figure H-11.

Table H-22—Basic Data Required for Analysis of HSC-HF

| Basic Data                          | Comments                                                                                                                                                                                                                                                                                                                                                        |
|-------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Presence of HF<br>(Yes or No)       | Determine whether HF may be present in the equipment/piping. Consider not only normal operating conditions, but also upset conditions that may allow carryover of HF from other equipment.                                                                                                                                                                      |
| Brinell Hardness of Steel Weldments | Determine the maximum Brinell hardness actually measured at the weldments of the steel equipment/piping. Reading should be made and reported using Brinell scale, not converted from microhardness techniques (e.g., Vicker, Knoop, etc.). If actual readings are not available, use the maximum allowable hardness permitted by the fabrication specification. |
| PWHT of Weldments<br>(Yes or No)    | Determine whether all the weldments of the equipment/piping have been properly post weld heat treated after welding.                                                                                                                                                                                                                                            |

Table H-23—Susceptibility to HSC-HF for Carbon and Low Alloy Steel

| As-Welded<br>Max Brinell Hardness |         |       | PWHT<br>Max Brinell Hardness |         |       |
|-----------------------------------|---------|-------|------------------------------|---------|-------|
| < 200                             | 200–237 | > 237 | < 200                        | 200–237 | > 237 |
| Low                               | Medium  | High  | Not                          | Low     | High  |

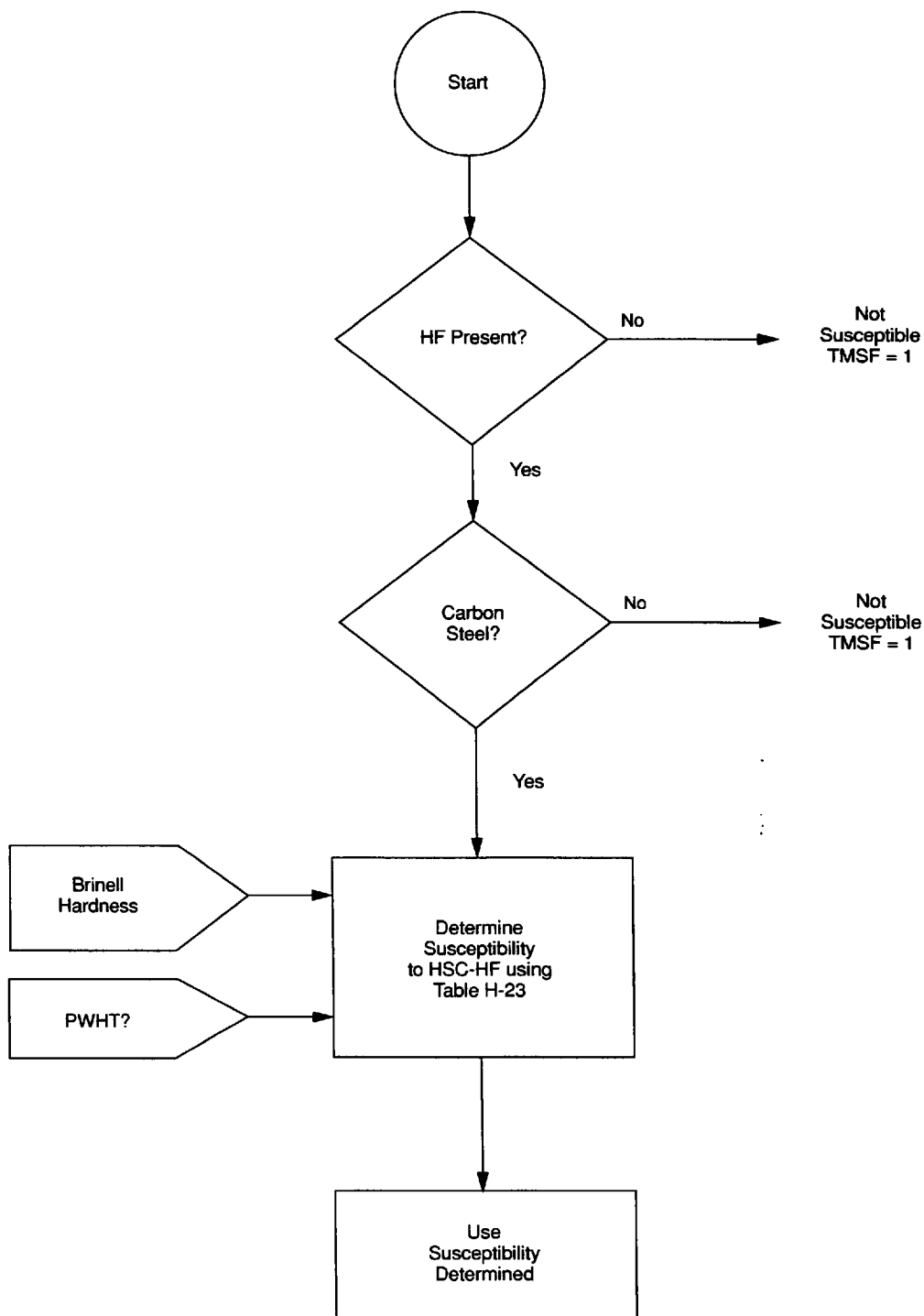


Figure H-11—Determination of Susceptibility to HSC-HF

## References

1. T. F. Degnan, "Material of Construction for Hydrofluoric Acid and Hydrogen Fluoride," *Process Industries Corrosion*, NACE, Houston, TX 1986.
2. *Corrosion Resistance of Nickel-Containing Alloy in Hydrofluoric Acid, Hydrogen Fluoride and Fluorine*, Corrosion Engineering Bulletin CEB-5, The International Nickel Co., Inc., 1968.

## H.13 Hydrogen-Induced Cracking and Stress-Oriented Hydrogen Induced Cracking in Hydrofluoric Acid Services (HIC/SOHIC-HF)

### H.13.1 DESCRIPTION OF DAMAGE

Hydrogen-induced cracking is defined as stepwise internal cracks that connect adjacent hydrogen blisters on different planes in the metal, or to the metal surface. No externally applied stress is needed for the formation of HIC. The driving force for the cracking is high stress at the circumference of the hydrogen blisters caused by buildup of internal pressure in the blisters. Interaction between these high stress fields tends to cause cracks to develop that link blisters on different planes in the steel.

The source of hydrogen in the steel is the corrosion reaction with either wet hydrogen sulfide (covered in H.8) or hydrofluoric acid (HF). HF is used in HF alkylation units at concentrations in the range 96–99+% HF-in-water. Exposure of carbon steel to aqueous or anhydrous HF may result in HIC/SOHIC.

Hydrogen blisters are planar hydrogen-filled cavities formed at discontinuities in the steel (i.e., voids, inclusions, laminations, sulfide inclusions). Blisters most often occur in rolled plate steels with a banded microstructure resulting from elongated sulfide inclusions. Susceptibility to hydrogen blistering, and therefore HIC, is primarily related to the quality of the plate steel (i.e., the number, size and shape of the discontinuities). In this regard, the sulfur content of the steel is a primary material parameter. Reducing the sulfur content of the steel reduces the susceptibility to blistering and HIC. Addition of calcium for sulfide inclusion shape control is generally beneficial.

SOHIC is defined as a stacked array of small blisters joined by hydrogen-induced cracking that is aligned in the through-thickness direction of the steel as a result of high localized tensile stresses. SOHIC is a special form of HIC which usually occurs in the base metal adjacent to the heat-affected

zone of a weld, where there are high residual stresses from welding. As with HIC, plate steel quality is a key parameter of SOHIC susceptibility. In addition, reduction of residual stresses by PWHT can reduce, but may not eliminate, the occurrence and severity of SOHIC.

### H.13.2 BASIC DATA

Table H-24 lists the basic data required for analysis of susceptibility of carbon steel equipment to HIC/SOHIC-HF. If the sulfur content of the steel is not known, contact a knowledgeable materials engineer to obtain an estimate of steel quality.

### H.13.3 DETERMINATION OF SUSCEPTIBILITY TO HF HIC/SOHIC

If HF is present in any concentration, then the equipment/piping is potentially susceptible to HIC/SOHIC-HF. Basic data from Table H-24 should be used to obtain the susceptibility rating from Table H-25 for carbon steel. Piping fabricated from wrought components of conventional steels (i.e., A 53, A 106, API 5L [not including 5LX], A 234, A 105, etc.) should be considered to have a low susceptibility to HIC/SOHIC-HF. For equipment, and large diameter piping fabricated from rolled and welded plate steel, the susceptibility should be determined using Table H-25. A flow chart of the steps required to determine the susceptibility is presented in Figure H-11.

The susceptibility of the steel to blistering is directly related to the cleanliness of the steel which is measured by sulfur content. It should be recognized that blistering is not a damage mechanism which will lead to a leak path unless it is accompanied by hydrogen-induced cracking leading to the surface. Blistering does pose a danger to mechanical integrity when it approaches a weld which contains sufficient residual stresses to drive the hydrogen-induced cracking to the surfaces. It is in this last case, the most severe situation, that is considered when determining the susceptibility to HIC/SOHIC-HF.

## References

1. T. F. Degnan, "Material of Construction for Hydrofluoric Acid and Hydrogen Fluoride," *Process Industries Corrosion*, NACE, Houston, TX 1986.
2. *Corrosion Resistance of Nickel-Containing Alloy in Hydrofluoric Acid, Hydrogen Fluoride and Fluorine*, Corrosion Engineering Bulletin CEB-5, The International Nickel Co., Inc., 1968.

Table H-24—Basic Data Required for Analysis of HIC/SOHIC-HF

| Basic Data                       | Comments                                                                                                                                                                                                                                                                                                           |
|----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Presence of HF<br>(Yes or No)    | Determine whether HF may be present in the equipment/piping. Consider not only normal operating conditions, but also upset conditions that may allow carryover of HF from other equipment.                                                                                                                         |
| PWHT of weldments<br>(Yes or No) | Determine whether all the weldments of the equipment/piping have been properly post weld heat treated.                                                                                                                                                                                                             |
| Sulfur Content of Plate Steel    | Determine the sulfur content of the plate steel used to fabricate the equipment/piping. This information should be available on MTR's in equipment files. If not available, it can be estimated from the ASTM or ASME specification of the steel listed on the U-1 form in consultation with a materials engineer. |

Table H-25—Susceptibility to HIC/SOHIC-HF

| High Sulfur Steel <sup>a</sup><br>> 0.01% S |      | Low Sulfur Steel <sup>b</sup><br>0.002–0.01% S |        | Ultra Low Sulfur Steel <sup>c</sup><br>< 0.002% S |      |
|---------------------------------------------|------|------------------------------------------------|--------|---------------------------------------------------|------|
| As-welded                                   | PWHT | As-welded                                      | PWHT   | As-welded                                         | PWHT |
| High                                        | High | High                                           | Medium | Medium                                            | Low  |

<sup>a</sup>Typically includes A 70, A 201, A 212, A 285, A 515, and most A 516 before about 1990.

<sup>b</sup>Typically includes early generations of HIC-resistant A 516 in 1980s, with Ca additions.

<sup>c</sup>Typically includes later generations of HIC-resistant A 516 in 1990s.

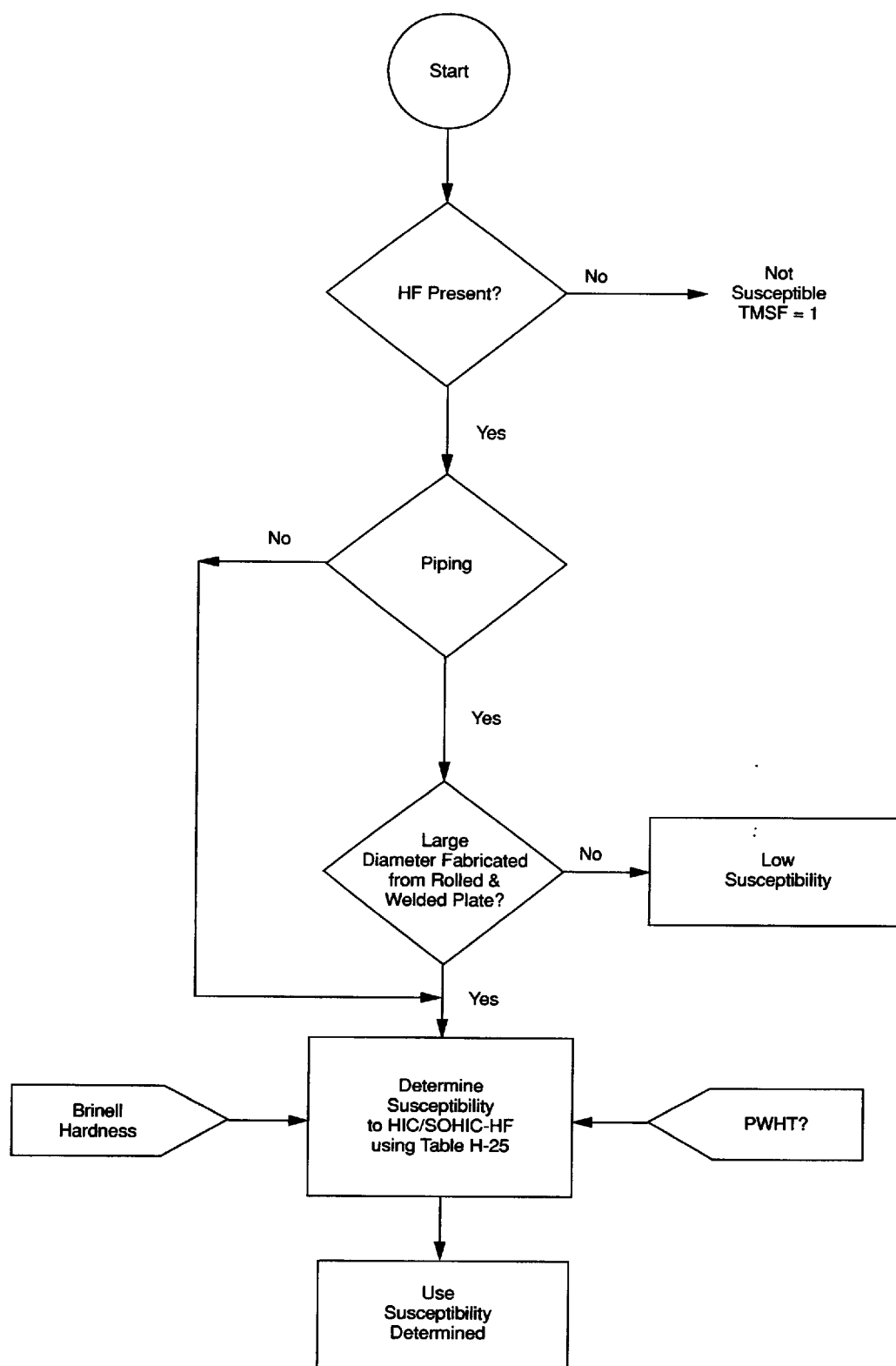


Figure H-12—Determination of Susceptibility to HIC/SOHIC HF

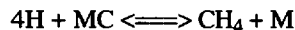
## APPENDIX I—HIGH TEMPERATURE HYDROGEN ATTACK (HTHA) TECHNICAL MODULE

### I.1 Scope

High temperature hydrogen attack (HTHA) occurs in carbon and low alloy steels exposed to a high partial pressure of hydrogen at elevated temperatures. It is the result of atomic hydrogen diffusing through the steel and reacting with carbides in the microstructure. There are two reactions associated with HTHA. First the hydrogen molecule,  $H_2$ , must dissociate to form atomic hydrogen,  $H$ , which can diffuse through steel.



The reaction to form atomic hydrogen occurs more readily at higher temperatures and higher hydrogen partial pressures. As a result, as both temperature and hydrogen partial pressure are increased, the driving force for HTHA increases. The second reaction that occurs is between atomic hydrogen and the metal carbides.



Damage due to the HTHA can possess two forms, internal decarburization and fissuring from the accumulation of methane gas at the carbide matrix interface and surface decarburization from the reaction of the atomic hydrogen with carbides at or near the surface where the methane gas can escape without causing fissures. Internal fissuring is more typically observed in carbon steel,  $C^{1/2}Mo$  steels and in Cr-Mo steels at higher hydrogen partial pressures, while surface decarburization is more commonly observed in Cr-Mo steels at higher temperatures and lower hydrogen partial pressures.

HTHA can be mitigated by increasing the alloy content of the steel and, thereby, increasing the stability of the carbides in the presence of hydrogen. As a result, carbon steel that only contains  $Fe_3C$  carbides has significantly less HTHA resistance than any of the Cr-Mo steels that contain Cr and Mo carbides that are more stable and resistant to HTHA.

Historically, HTHA resistance has been predicted based on industry experience which has been plotted on a series of curves for carbon and low alloy steels showing the temperature and hydrogen partial pressure regime in which these steels have been successfully used without damage due to HTHA. These curves, which are commonly referred to as the Nelson curves, are maintained based on industry experience in API Recommended Practice 941.

### I.2 Technical Module Screening Questions

The screening questions for HTHA listed in Table I-1 are used to determine if the module for HTHA should be entered.

### I.3 Basic Data

The data listed in Table I-2, if available, can be used to estimate susceptibility of HTHA for carbon and low alloy steels. If exact process conditions are not known, contact a knowledgeable process engineer to obtain the best estimates

### I.4 Basic Assumptions

The assessment of susceptibility to HTHA is based on the time the equipment has been exposed to high pressure hydrogen at elevated temperatures. A single parameter,  $P_V$ , has been developed to relate time at temperature and a hydrogen partial pressure. This parameter has been defined in the literature as follows:

$$P_V = \log(P_{H_2}) + 3.09 \times 10^{-4}(T)(\log(t) + 14)$$

where

$$P_{H_2} = \text{the hydrogen partial pressure in kgf/cm}^2 \\ (1 \text{ kgf/cm}^2 = 14.2 \text{ psia}),$$

$$T = \text{the temperature in } ^\circ K \text{ } (^{\circ} K = ^{\circ} C + 273),$$

$$t = \text{time in hours.}$$

This parameter can be used to define the susceptibility of a material to damage from HTHA. For the basis of this Technical Module, the susceptibility to damage from HTHA is based on 200,000 hours of service at a given combination of temperature and hydrogen partial pressure.

### I.5 Determination of Susceptibility

Based on the  $P_V$  calculations and basic assumptions the ranges shown in Table I-3 have been defined for carbon and low alloy steel susceptibility to HTHA.

### I.6 Inspection Effectiveness

The nature of HTHA makes detection by conventional inspection techniques very difficult. Table I-4 shows examples of inspection effectiveness for commonly used inspection techniques to detect HTHA.

### I.7 Determination of Technical Module Subfactor

This Technical Module assumes that susceptibility to HTHA is determined in Table I-3. The susceptibility is designated as high, medium, low, or not susceptible. Based on this susceptibility rating of high, medium, or low, a severity index is assigned which reflects no inspection or monitoring credits.

Table I-1—Screening Questions for HTHA Module

| Screening Questions                                                       | Action                                      |
|---------------------------------------------------------------------------|---------------------------------------------|
| 1. Is the material carbon or low alloy steel?                             | If Yes to both, proceed to module for HTHA. |
| 2. Is the operating temperature > 400°F and operating pressure > 80 psia? |                                             |

Table I-2—Basic Data Required for Analysis of HTHA

| Basic Data                                                   | Comments                                                                                                                                                                                                                                            |
|--------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Material of Construction                                     | Determine the material of construction of the equipment/piping.                                                                                                                                                                                     |
| Heat Treatment Condition of C <sup>1</sup> / <sub>2</sub> Mo | Determine whether C <sup>1</sup> / <sub>2</sub> Mo steel heat treatment was annealed or normalized. C <sup>1</sup> / <sub>2</sub> Mo in the annealed condition can have HTHA resistance no better than carbon steel. Default is annealed condition. |
| Hydrogen Partial Pressure (kgf/cm <sup>2</sup> )             | Determine the hydrogen partial pressure, which is equal to mole fraction of hydrogen times the total pressure (absolute).<br>1 kgf/cm = 14.2 psia                                                                                                   |
| Temperature (degrees Kelvin = °K)                            | Determine the temperature of exposure.<br>$^{\circ}\text{K} = \left[ \frac{^{\circ}\text{F} - 32}{1.8} \right] + 273$                                                                                                                               |
| Time (hours)                                                 | Determine time of exposure in hours.                                                                                                                                                                                                                |

Table I-3—Carbon and Low Alloy Steel Susceptibility to HTHA

| Materials                                                     | Critical P <sub>V</sub> Factors |                              |                              |                       |
|---------------------------------------------------------------|---------------------------------|------------------------------|------------------------------|-----------------------|
|                                                               | High Susceptibility             | Medium Susceptibility        | Low Susceptibility           | Not Susceptible       |
| Carbon Steel                                                  | P <sub>V</sub> > 4.70           | 4.61 < P <sub>V</sub> ≤ 4.70 | 4.53 < P <sub>V</sub> ≤ 4.61 | P <sub>V</sub> ≤ 4.53 |
| C <sup>1</sup> / <sub>2</sub> Mo <sup>a</sup><br>(Annealed)   | P <sub>V</sub> > 4.95           | 4.87 < P <sub>V</sub> ≤ 4.95 | 4.78 < P <sub>V</sub> ≤ 4.87 | P <sub>V</sub> ≤ 4.78 |
| C <sup>1</sup> / <sub>2</sub> Mo <sup>a</sup><br>(Normalized) | P <sub>V</sub> > 5.60           | 5.51 < P <sub>V</sub> ≤ 5.60 | 5.43 < P <sub>V</sub> ≤ 5.51 | P <sub>V</sub> ≤ 5.43 |
| 1 C <sup>1</sup> / <sub>2</sub> <sup>b</sup>                  | P <sub>V</sub> > 5.80           | 5.71 < P <sub>V</sub> ≤ 5.80 | 5.63 < P <sub>V</sub> ≤ 5.71 | P <sub>V</sub> ≤ 5.63 |
| 1 <sup>1</sup> / <sub>4</sub> Cr-1/2 Mo <sup>b</sup>          | P <sub>V</sub> > 6.00           | 5.92 < P <sub>V</sub> ≤ 6.00 | 5.83 < P <sub>V</sub> ≤ 5.92 | P <sub>V</sub> ≤ 5.83 |
| 2 <sup>1</sup> / <sub>4</sub> Cr-1 Mo                         | P <sub>V</sub> > 6.53           | 6.45 < P <sub>V</sub> ≤ 6.53 | 6.36 < P <sub>V</sub> ≤ 6.45 | P <sub>V</sub> ≤ 6.36 |

<sup>a</sup>Default annealed. Only use normalized, if known.

<sup>b</sup>For hydrogen partial pressure levels greater than 1200 psia use the critical P<sub>V</sub> factors for 1<sup>1</sup>/<sub>4</sub> Cr-1/2 Mo.

Note: No debit has been applied for steels with high levels of tramp elements such as As, Sb, Sn, and P. If high level of tramp elements are suspected, the critical P<sub>V</sub> factors should be reduced. The critical P<sub>V</sub> factor can be as much as 0.25 lower for heats of steels with high levels of tramp elements.

Table I-4 Inspection Effectiveness Guidelines for HTHA

| Inspection Effectiveness Category | Typical Inspection Practices                                                                                                       |
|-----------------------------------|------------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | None                                                                                                                               |
| Usually Effective                 | Extensive Advanced Ultrasonic Backscatter Technique (AUBT), spot AUBT based on stress analysis or extensive in-situ metallography. |
| Fairly Effective                  | Spot AUBT or spot in-situ metallography.                                                                                           |
| Poorly Effective                  | Ultrasonic backscatter plus attenuation.                                                                                           |
| Ineffective                       | Attenuation only                                                                                                                   |



Using the basic data from Table I-2, see Figure I-1 to determine the technical module subfactor for HTHA.

The base level technical subfactor can be adjusted downward if an effective inspection is performed and NO DAMAGE is detected. As with stress corrosion cracking type of damage, if damage is found during inspection, a significant upward adjustment is made to the subfactor. It should be noted that once damage is observed a fitness-for-service assessment should be performed. The following upward adjustments should be made to the base level technical module subfactor if damage is observed during an inspection, while the following downward adjustments should be made

to the base level technical subfactor for the various levels of inspection effectiveness if NO DAMAGE is found. The following includes credit for both a first inspection and second inspection where no HTHA damage is observed.

Table I-5 provides the technical module subfactor for various levels of susceptibility to HTHA and level of inspection. The table also provides a technical subfactor for situations when inspection uncovers HTHA damage. The technical module subfactor has been provided for two inspections. For a greater number of inspections, the technical module subfactors remain constant.

Table I-5—Technical Subfactors Adjusted for Effective Inspection

| Severity Index        | No Inspection | First Inspection<br>Inspection Effectiveness |        |         | Second Inspection<br>Inspection Effectiveness |        |         |
|-----------------------|---------------|----------------------------------------------|--------|---------|-----------------------------------------------|--------|---------|
|                       |               | Poorly                                       | Fairly | Usually | Poorly                                        | Fairly | Usually |
| Damage Observed       | —             | 2000                                         | 2000   | 2000    | 2000                                          | 2000   | 2000    |
| High Susceptibility   | 2000          | 1800                                         | 1200   | 800     | 1600                                          | 800    | 400     |
| Medium Susceptibility | 200           | 1800                                         | 1200   | 80      | 160                                           | 80     | 40      |
| Low Susceptibility    | 20            | 18                                           | 12     | 8       | 16                                            | 8      | 4       |
| No Susceptibility     | 1             | 1                                            | 1      | 1       | 1                                             | 1      | 1       |

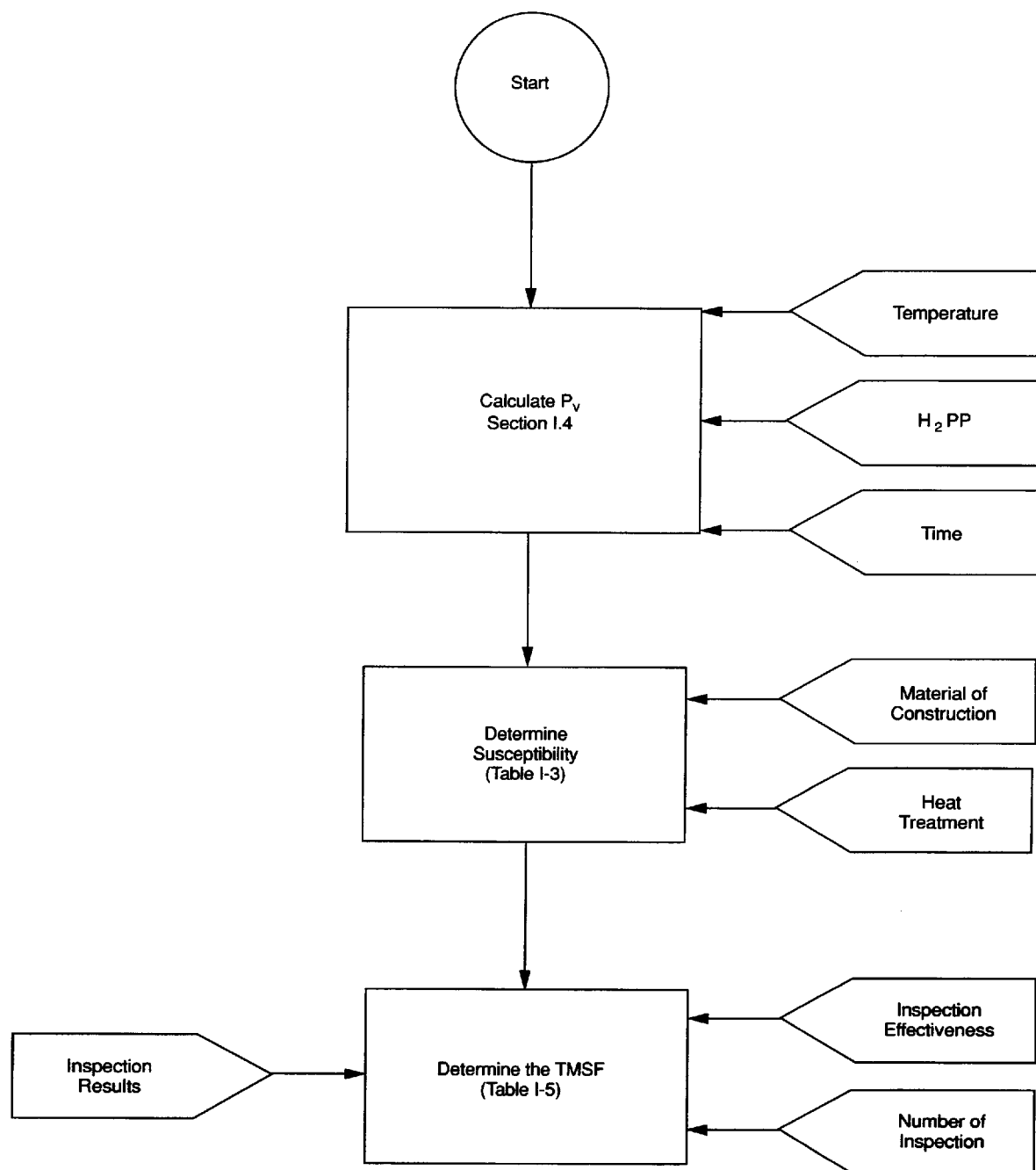


Figure I-1—Determination of HTHA Corrosion Rates

## APPENDIX J—FURNACE TUBE TECHNICAL MODULE

### J.1 Likelihood Analysis

#### J.1.1 INTRODUCTION

The probability of failure for furnace tubes is calculated directly in the furnace technical module with the following generic failure frequencies for long term creep. If short-term creep is possible, the generic failure frequencies are multiplied by a factor of 100, as shown in Table J-1.

Table J-1—Furnace Tube Generic Failure Frequencies

| Hole Size | Long-Term Creep         | Short-Term Creep        |
|-----------|-------------------------|-------------------------|
| 1/4 in.   | 0.0                     | 0.0                     |
| 1 in.     | 4.62 x 10 <sup>-6</sup> | 4.62 x 10 <sup>-4</sup> |
| 4 in.     | 1.32 x 10 <sup>-6</sup> | 1.32 x 10 <sup>-4</sup> |
| Rupture   | 6.60 x 10 <sup>-7</sup> | 6.60 x 10 <sup>-5</sup> |

#### J.1.2 SCOPE

This module establishes a damage factor (probability of failure modifier) for externally fired furnace tubes. This technical module applies to ferritic steel (carbon steel and low alloy steels through 12 Cr) and austenitic stainless steel (Types 304, 316, 321 and 347) tubes in refinery heaters. These tubes are assumed to be direct fired, heat absorbing and enclosed within a firebox. This module addresses damage caused by long term exposure to temperature as well as short term over-heating.

#### J.1.3 TECHNICAL MODULE SCREENING QUESTIONS

Table J-2—Screening Questions for Furnace Technical Module

| Screening Questions                                                                        | Action                                                                                                          |
|--------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------|
| 1. Is the type of equipment a fired heater or furnace used to heat liquid process streams? | If <b>Yes</b> , continue through the Furnace Tube Technical Module.<br><br>If <b>No</b> , exit Technical Module |

#### J.1.4 BASIC DATA

The basic data listed in Table J-3 are the minimum required to determine the technical module subfactor for furnace tubes.

#### J.1.5 BASIC ASSUMPTIONS

**J.1.5.1** Generally, fired heater tubes in refineries are designed to comply with API RP 530. This recommended practice is used to select the minimum wall thickness

required for heater tubes as a function of the material of construction, the temperature and the applied stress. The recommended practice addresses both creep and corrosion damage. While allowances for corrosion are made, API RP 530 specifies minimum allowable tube wall thickness based on the estimated creep life. At elevated temperatures, components subject to a constant stress fail after a period of time. This time to failure decreases as the stress or the temperature increases.

**J.1.5.2** For the material of construction, API RP 530 presents two creep strengths: the mean strength and the minimum strength. The mean curves in API RP 530 correspond to the average creep strength of the heater tube material while the minimum curves correspond to the strength that is exceeded by 95% of heater tube material.

**J.1.5.3** The relationship between creep life, stress and temperature is relatively complex. However, heater tube design methods use simplified relationships developed from accelerated tensile creep tests. The scatter in the results of these uni-axial creep tests is relatively large. Because of this scatter in experimental creep properties and dependence on accelerated creep tests for the creep properties, there is a significant amount of uncertainty associated with the prediction of creep life.

**J.1.5.4** The prediction of heater tube life is further complicated by other effects as listed below:

- External oxidation. The most common corrosion problem in heater tubes is external oxidation of the tubes. Oxidation thins the tube wall, increasing the stress and accelerating the rate of creep damage. The oxidation rate is a function of temperature and amount of oxygen in the firebox.
- Internal corrosion. In some refinery furnaces, such as in Crude Distillation units, high temperature sulfidation can be a problem. As corrosion thins the tube wall, the stress increases and the rate of creep damage is accelerated. The rate of high temperature sulfidation is a function of temperature and sulfur content in the process stream.
- Other corrosion. Because the tubes are operated at high temperatures, even small amounts of contaminants in either the process or fuel can cause accelerated corrosion of the tube metal. For example, the combination of high temperatures and small amounts of sodium and vanadium in the fuel can cause excessive external corrosion.
- Uneven heating. The temperature distribution in heater fireboxes is affected by the positioning of the tubes relative to the burners, the shape and size of the firebox, the tube spacing, and the distances between the tubes and the burners.

Table J-3—Basic Data Required for Analysis of Furnace Tubes

| Basic Data                                              | Comments                                                                                                                                                                                                                                                                                                           |
|---------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Material of Construction                                | Determine the material of construction of the tubes.                                                                                                                                                                                                                                                               |
| Time in service, $t_i$ (years)                          | Determine the total number of years that the tubes have been in service. If the tubes were in a previous service in which creep failure was not a concern, this time may be ignored. Assume 8,500 hours of operation per year.                                                                                     |
| Time since previous inspection (years)                  | Determine the number of years since the previous inspection for which there is thickness data. This time will be used, along with a calculated corrosion rate, to determine the current thickness.                                                                                                                 |
| Corrosion Rate (mpy)                                    | Determine the current rate of thinning calculated from thickness data, if available. If the thinning rate has not been established by inspection, then estimated thinning rates may be determined from this module and Thinning Supplements C, D, and I.                                                           |
| Operating Tube Metal Temperature, $TMT$ (°F)            | Determine the average operating tube metal temperature determined from thermography or skin thermocouples. If the tube temperature is not available, use process outlet temperature plus 100°F for nonfouling, noncoking service. For tubes in fouling or coking service, add 150°F to process outlet temperature. |
| Operating Pressure, $p$ (psi)                           | Determine the highest expected operating pressure (may be the relief valve set pressure unless pressures that high are unlikely).                                                                                                                                                                                  |
| Tube Diameter, $D_o$ (inch)                             | Determine the tube outer diameter used for design calculations at time of construction.                                                                                                                                                                                                                            |
| Tube Wall Thickness (inch)                              | Determine the actual measured thickness from the last inspection. If inspection results are not available, then determine the new construction minimum thickness.                                                                                                                                                  |
| Inspection Effectiveness Category                       | Determine the effectiveness category of each inspection that has been performed on the equipment during the time period (specified above). See Table J-7 for guidelines to assign inspection effectiveness categories for furnace tubes.                                                                           |
| Number of Inspections                                   | Determine the number of inspections in each category that have been performed during the time period specified above.                                                                                                                                                                                              |
| Severity of possible over-heating, $\Delta T_{oh}$ (°F) | Estimate the magnitude of extreme temperature excursions, from 0°F–300°F over the design tube metal temperature (not the operating tube metal temperature). See J.1.15 for guidance on choosing the appropriate level of over-heating.                                                                             |
| Duration of possible over-heating, $t_{oh}$ (hours)     | Estimate the accumulated duration of extreme over-heating events.                                                                                                                                                                                                                                                  |
| On-Line Monitoring                                      | Determine the types of proactive corrosion monitoring methods or tools employed, such as tube skin thermocouples, thermography, process operating variables, etc.                                                                                                                                                  |

e. Flame impingement. Flame impingement is affected by the same factors of uneven heating; however, it is also affected by the adjustment of the burners and the control of fuel and air in the fire box.

f. Coking. In many types of petroleum heaters, coke deposits build up on the inside of the tube. The coke deposits act as a thermal insulation between the tube metal and the process, raising the temperature of the tube wall, accelerating creep and corrosion.

**J.1.5.5** This technical module assumes that the long-term creep does not occur unless the operating tube wall metal temperature is higher than the temperatures given for each material of construction in Table J-4. Local overheating; how-

ever, may occur as a result of uneven heating or flame impingement and is addressed for all furnaces.

**J.1.5.6** Failure resulting from long term exposure at temperatures in excess of those outlined in Table J-4 is assumed to result from creep and creep cracking. The limit states used to estimate the life for design is covered in detail in API RP 530. If the expected tube metal temperatures are less than those listed in Table J-4, the furnace tubes should be assessed using the technical module for general thinning. If however, the tube could be exposed to high metal temperatures for short time intervals, Section J.1.15 should be used to determine the short-term failure potential.

Table J-4—Metal Temperature Limit for Creep Consideration

| Material Type      | Elastic Temperature Limit (°F) <sup>a</sup> |
|--------------------|---------------------------------------------|
| Carbon steel       | 770                                         |
| 1/2 Mo             | 920                                         |
| 1 1/4 Cr - 1/2 Mo  | 930                                         |
| 2 1/4 Cr - 1 Mo    | 900                                         |
| 3 Cr - 1 Mo        | 920                                         |
| 5 Cr - 1/2 Mo      | 880                                         |
| 5 Cr - 1/2 Mo - Si | 840                                         |
| 7 Cr - 1/2 Mo      | 850                                         |
| 9 Cr - 1 Mo        | 960                                         |
| 12 Cr              | 800                                         |
| 304/304H SS        | 1080                                        |
| 316/316H SS        | 1120                                        |
| 321 SS             | 1010                                        |
| 321H SS            | 1040                                        |
| 347/347H SS        | 1100                                        |

<sup>a</sup>Temperature at which a tube would have 100,000 hr. design life using minimum rupture strength curve per API RP 530.

### J.1.6 DETERMINATION OF TECHNICAL MODULE SUBFACTORS (TMSF)

The technical module subfactor is determined using the procedure outlined in Figure J-1. Because there are two modes of failure, there are two parts to this procedure: a procedure that estimates the likelihood of a long term creep failure and a procedure that estimates the likelihood of a short-term over-heating failure. This results in two estimates of the TMSF. The maximum of these two estimates is used.

### J.1.7 DETERMINATION OF ACTUAL TUBE METAL TEMPERATURE (TMT)

Determine the average operating tube metal temperature as measured by thermography or skin thermocouples. If the measured TMT is not available, it can be estimated by using the process outlet temperature + 100°F for non-coking service, and + 150°F for coking service.

### J.1.8 DETERMINATION OF ELASTIC METAL TEMPERATURE LIMIT

The critical tube metal temperature ( $T_{elas}$ ) is determined by using the following table for various materials of construction:

If the actual tube metal temperature is less than the critical temperature tabulated above, then long-term creep is not a consideration. However, short-term over-heating should be considered using the methods described in J.1.15.

## J.1.9 DETERMINATION OF CORROSION RATE

**J.1.9.1** The average corrosion rate should be calculated from thickness data available from furnace tube inspections, if available.

**J.1.9.2** If a calculated thinning rate is not available, estimated thinning rates should be determined for each potential thinning mechanism (See Appendix G) using high temperature sulfidic and naphthenic acid corrosion (see G.7), high temperature H<sub>2</sub>S/H<sub>2</sub> corrosion (see G.8), and high temperature oxidation (see G.13). The screening questions in Table G-4 should be used to determine which of the thinning mechanisms apply. These thinning rates will be added to give a composite thinning rate. Alternatively, expert advice may be used to establish the maximum thinning rate.

### J.1.10 DETERMINATION OF CURRENT WALL THICKNESS ( $T_{current}$ )

Determine the current thickness using the corrosion rate and thickness obtained from the last known inspection. If no inspections have been performed, use the original tube wall thickness, the total time in service and the estimated corrosion rate determined in J.1.9 to estimate the current thickness.

### J.1.11 CALCULATION OF STRESS

Calculate the stress in the tube,  $S$  using the current thickness ( $T_{current}$ ), operating pressure ( $p$ ), and tube outside diameter ( $D_o$ ), as shown in the equation below.

$$S = \frac{p}{2} \left( \frac{D_o}{T_{current}} - 1 \right) \quad (J-1)$$

If the tube stress is less than that tabulated in Table J-5, long term creep is not a concern. However short term over-heating should still be considered as described in J.1.15.

### J.1.12 DETERMINATION OF LONG-TERM FAILURE PROBABILITY

The probability of failure as a result of long term creep is calculated following these steps:

- The mean Larson Miller parameter,  $L_{Mavg}$ , is determined using the expressions in Table J-6 at the stress level calculated in Calculation of Stress.
- The Larson Miller parameter at the current operating conditions is calculated using the following equation.

$$lm = \frac{TMT + 460}{1000} \leftrightarrow (\log t_i + C) \quad (J-2)$$

where TMT is the operating tube metal temperature in degrees F,  $t_i$  is the total time in service in hours and  $C$  is tabulated for each material of construction in Table J-6.

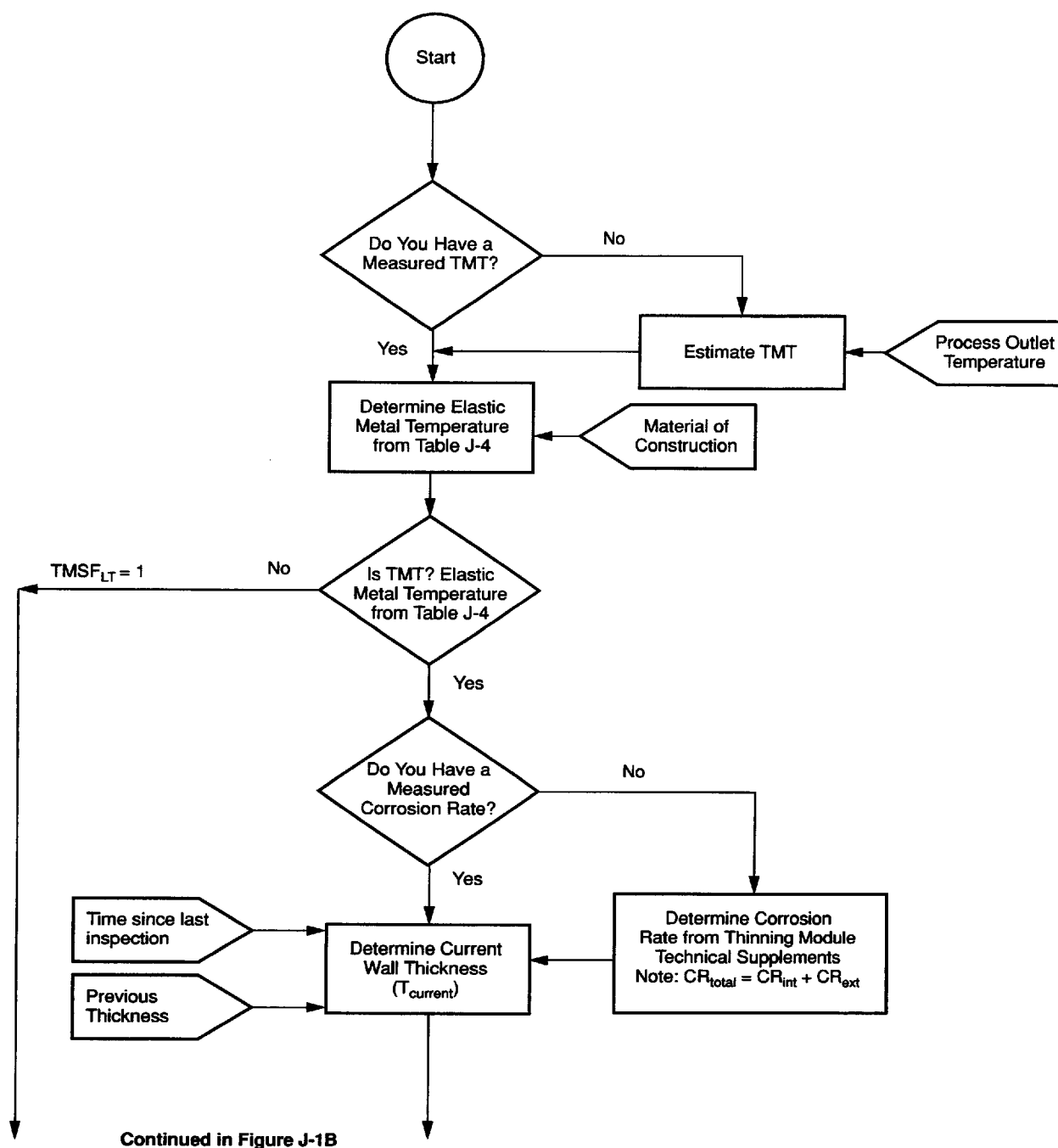


Figure J-1A—Determination of Technical Module Subfactors for Furnace Tubes

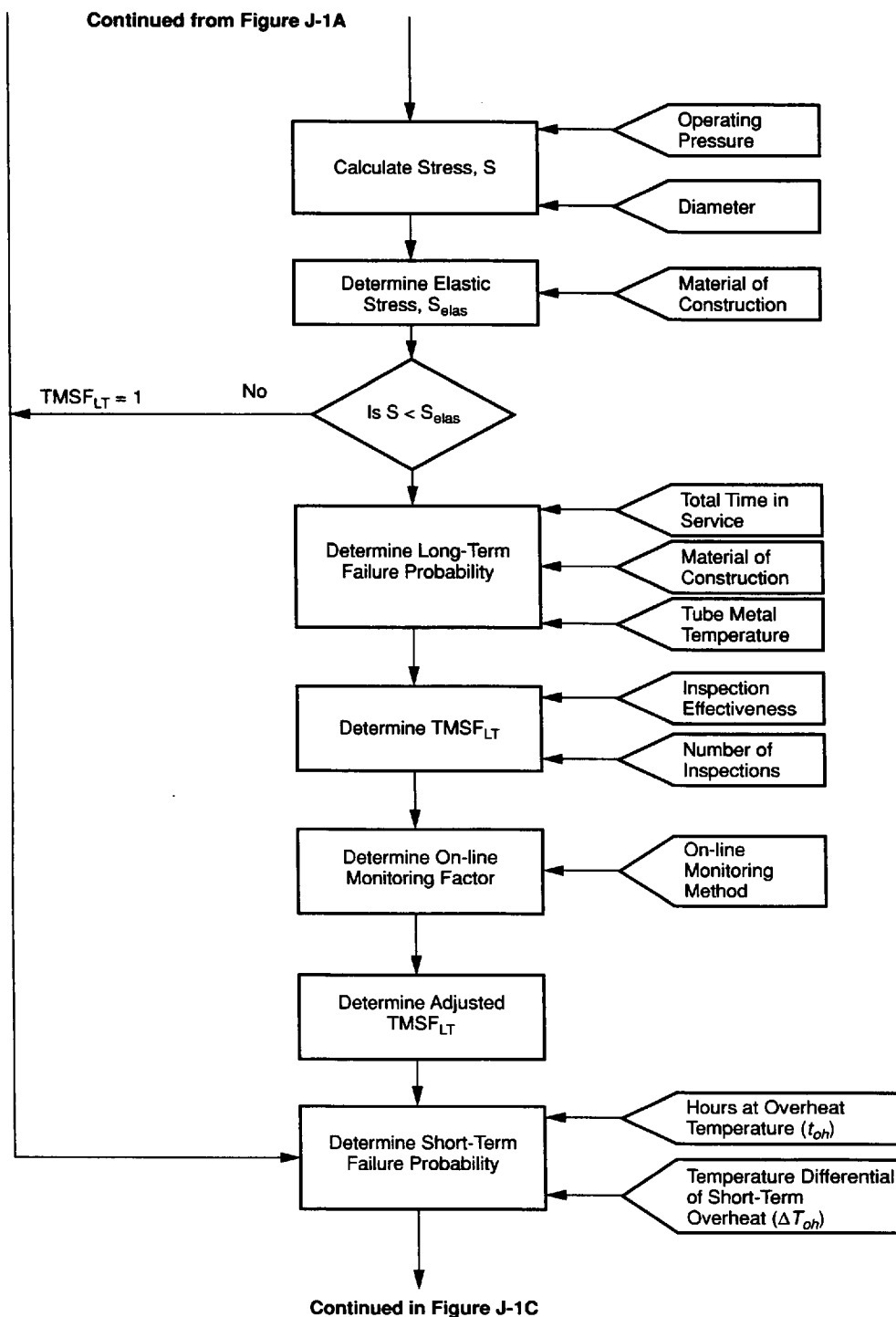


Figure J-1B—Determination of Technical Module Subfactors for Furnace Tubes

Continued from Figure J-1B

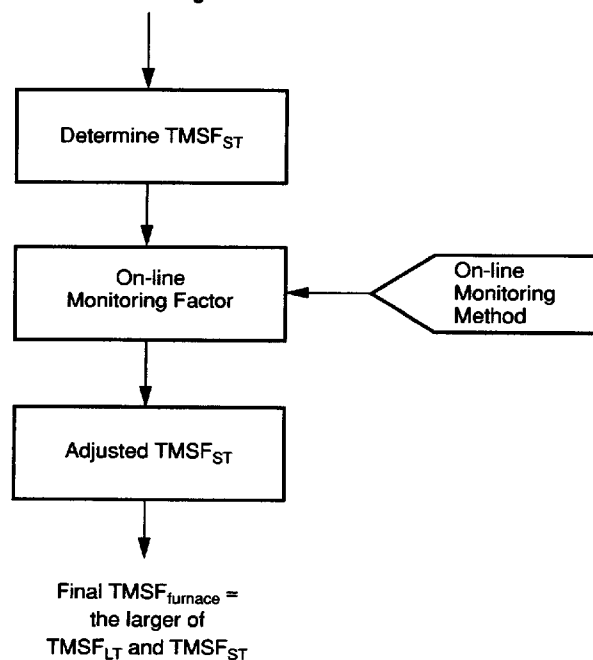


Figure J-1C—Determination of Technical Module Subfactors for Furnace Tubes

Table J-5—Tube Stress Limit for Creep Consideration

| Material Type      | Elastic Stress Limit (ksi) |
|--------------------|----------------------------|
| Carbon steel       | 3.2                        |
| 1/2 Mo             | 1.75                       |
| 1 1/4 Cr-1/2 Mo    | 2.6                        |
| 2 1/4 Cr - 1 Mo    | 2.2                        |
| 3 Cr - 1 Mo        | 2.4                        |
| 5 Cr - 1/2 Mo      | 2.4                        |
| 5 Cr - 1/2 Mo - Si | 1.7                        |
| 7 Cr- 1/2 Mo       | 1.5                        |
| 9 Cr - 1 Mo        | 1.25                       |
| 12 Cr              | 2.1                        |
| 304/304H SS        | 2.4                        |
| 316/316H SS        | 1.85                       |
| 321 SS             | 1.85                       |
| 321H SS            | 2.05                       |
| 347/347HSS         | 1.95                       |

c. The parameter  $LM_{delta}$  is determined. This parameter is defined as the average difference between the mean and minimum Larson Miller curves in API RP 530. These values are tabulated in Table J-6.

d. The parameter  $X$  is determined using the mean and operating Larson Miller parameters and dividing the difference by  $LM_{delta}$ , as shown in the following equation.

$$X = (LM_{avg} - lm) / LM_{delta} \quad (J-3)$$

e. The failure factor is calculated using the following formula:

$$FF_{LT} = \min(1, 10^{-0.6723X^3 + 0.2854X^2 - 0.5905X - 0.3001}) \quad (J-4)$$

#### J.1.13 DETERMINATION OF LONG TERM TECHNICAL MODULE SUBFACTOR ( $TMSF_{LT}$ )

A technical module subfactor can be calculated from the failure factors using the following equation.

$$TMSF_{LT} = 0.55e^{13FF} \quad (J-5)$$



Table J-6—Larson Miller Parameter Expressions

| Material              | Expression for $LM_{avg}$                                            | $LM_{delta}$ | C  |
|-----------------------|----------------------------------------------------------------------|--------------|----|
| CS                    | $42.2443 - 0.000025156 S^3 - 1.24914 \sqrt{S} - 1.90435 \ln S$       | 0.34         | 20 |
| C - $1/2$ Mo          | $41.2074 - 0.000011355 S^3 - 2.30593 \ln S$                          | 0.62         | 20 |
| $1 1/4$ Cr - $1/2$ Mo | $42.601 - 2.62249 \ln S$                                             | 1.11         | 20 |
| $2 1/4$ Cr - $1/2$ Mo | $47.1367 - 4.18064 \ln S - \frac{1.8401}{\sqrt{S}} - 8.41296 \exp S$ | 0.85         | 20 |
| 3 Cr - 1 Mo           | $44.786 - 3.50144 \ln S$                                             | 0.69         | 20 |
| 5 Cr - $1/2$ Mo       | $45.5586 - 3.92851 \ln S$                                            | 1.41         | 20 |
| 5 Cr - $1/2$ Mo-Si    | $45.1928 - 4.06518 \ln S$                                            | 1.82         | 20 |
| 7 Cr - $1/2$ Mo       | $45.7938 - 4.42502 \ln S$                                            | 1.19         | 20 |
| 9 Cr - 1 Mo           | $44.7031 - 3.10233 \ln S$                                            | 1.32         | 20 |
| 12 Cr                 | $59.8012 - 13.6331 \ln S + 4.3462 \ln^2 S - 0.60141 \ln^3 S$         | 1.29         | 25 |
| 304/304H SS           | $43.1703 - 4.15807 \ln S$                                            | 1.57         | 15 |
| 316/316H SS           | $41.4735 - 3.3742 \ln S$                                             | 0.75         | 15 |
| 321 SS                | $39.8956 - 3.12309 \ln S$                                            | 1.97         | 15 |
| 321 H SS              | $42.1308 - 3.84328 \ln S$                                            | 1.63         | 15 |
| 347/347H SS           | $41.6803 - 3.38401 \ln S$                                            | 0.72         | 15 |

$S$  = tube stress, in ksi.

LM = Larson Miller parameter in ( $^{\circ}$ R) ( $\log_{10}$  hours).

### J.1.14 INSPECTION EFFECTIVENESS CATEGORY

Inspections are ranked according to their expected effectiveness at finding damage and correctly predicting remaining life of furnace tubes. The actual effectiveness of a given inspection technique or combination of techniques depends on the characteristics of the material of construction and the method used. Table J-7 provides an example of inspection activities for furnace tubes.

Nonintrusive inspections cannot be applied to heater tube inspection since internal entry into the firebox is necessary for this to occur.

The credit provided for inspection is determined by using the expressions in Table J-8.  $N$  is the number of inspections, or 4, whichever is the smaller.

Determine the  $TMSF_{Adj}$  using Equation J-6.

$$TMSF_{adjusted} = \frac{TMSF \times \text{Inspection Effectiveness}}{\text{Reduction Factor}} \quad (J-6)$$

The long term technical module subfactor may be modified to take credit for on-line monitoring using the guidance provided in J.1.16

Table J-7—Guidelines for Assigning Inspection Effectiveness

| Inspection Effectiveness Category | Example: Intrusive Inspection                                                                                                  |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------|
| Highly Effective                  | Visual inspection, UT thickness measurements of all tubes, and strapping at UT measurement locations, FMR at various locations |
| Usually Effective                 | Visual inspection, UT thickness measurements of all tubes                                                                      |
| Fairly Effective                  | Visual inspection with UT measurements of 75% of the tubes                                                                     |
| Poorly Effective                  | Visual inspection with spot UT measurements                                                                                    |
| Ineffective                       | Visual                                                                                                                         |

Table J-8—Inspection Effectiveness Reduction Factor

| Inspection Effectiveness Category | Expression for Reduction of TMSF<br>( $N$ = Number of inspections) |
|-----------------------------------|--------------------------------------------------------------------|
| Highly Effective                  | $\max(\min(1, (1.25N^2 - 10.15N + 25.75) / 100), 0)$               |
| Usually Effective                 | $\max(\min(1, (0.75N^2 - 9.65N + 33.75) / 100), 0)$                |
| Fairly Effective                  | $\max(\min(1, (1.75N^2 - 18.05N + 56.25) / 100), 0)$               |
| Poorly Effective                  | $\max(\min(1, (4N^2 - 39.60N + 119.5) / 100), 0)$                  |
| Ineffective                       | 1.0                                                                |

### J.1.15 DETERMINATION OF SHORT-TERM FAILURE PROBABILITY

**J.1.15.1** The method outlined in J.1.12 assumes steady or nearly steady operating conditions over the life of the furnace resulting in long term creep. This type of damage is not the only mode of failure that can occur. Short periods of exposure to high temperatures or flame impingement can also result in failure. While this mode of failure is common, it is much more difficult to assess quantitatively because it is caused by unexpected circumstances or upsets in the operation or firing of the furnace. The methods, charts and procedures outlined in this section are intended as guidance to the engineer in evaluating the potential susceptibility to short term failure caused by over-heating.

**J.1.15.2** Because such failures depend on a large array of factors too complex and varied to cast into an exact calculation, the method outlined here depends on two factors:

- The estimated severity of probable over-heating as measured by the difference between the tube metal temperature during the over-heating event and the design tube metal temperature. This quantity is denoted as  $\Delta T_{oh}$ .
- The estimated accumulated time of exposure to over-heating. This time of exposure is denoted as  $t_{oh}$ .

**J.1.15.3** The severity  $\Delta T_{oh}$  of a possible over-heating is a function of the factors covered below. Values of  $\Delta T_{oh}$  can range up to 300°F, indicating that in some locations of the furnace, the metal temperature can be as much as 300°F higher than the design tube metal temperature for short periods of time. Heaters that have one or more of the following problems should be assigned high values of  $\Delta T_{oh}$ .

- A history of over-heating. Heaters that have failed after unusually short periods of time should be assigned a high value of  $\Delta T_{oh}$ .
- Observed flame impingement.
- High possibility of heavy coking.

**J.1.15.4** The time of exposure  $t_{oh}$  is a measure of how frequent and how long over-heating events can or have lasted.

The value of  $t_{oh}$  can range between 10 and 1000 hours and indicates the amount of accumulated time that the furnace has been exposed to severe operating conditions. Heaters that should be assigned high values of  $t_{oh}$  may have one or more of the following problems:

- Unstable operation. Furnaces that have a history of unstable operation should be assigned a high value of  $t_{oh}$ .
- Burner control problems. Furnaces that have a history of burners that are difficult to adjust and control should be assigned a high  $t_{oh}$ .

**J.1.15.5** The probability of failure due to short term over-heating can be calculated following these steps.

**Step 1.** The quantity  $\Delta T_{5\%}$  is calculated using the function in Equation J-7 and the expected accumulated duration of over-heating events. This over-heating temperature,  $\Delta T_{5\%}$ , corresponds to values of  $\Delta T_{oh}$  that result in a 5% probability of failure in the LM curves.

$$\Delta T_{5\%} = 35.5 \ln(1029/t_{oh}) \quad (J-7)$$

Equation 7 assumes that a 1°F overheating event 1000 hours long is equivalent to a one hour long 250°F overheating event. The long duration event is calibrated based on the observation that if the tube has been operating for long times at its design pressure and temperature, the probability of failure is about 5%. The short event is calibrated by the observation that tubes that survive a short intense event such as a fire do not necessarily fail.

**Step 2.** As the actual over-heating temperature,  $\Delta T_{oh}$ , increases, the probability of failure increases as a function of the difference between  $\Delta T_{oh}$  and  $\Delta T_{5\%}$ . Use the function in Equation J-8 to calculate the failure factor for short term over-heating.

$$FF_{ST} = \min(0.05 e^{0.0422(\Delta T_{oh} - \Delta T_{5\%})}, 1.0) \quad (J-8)$$

### J.1.16 DETERMINATION OF SHORT-TERM TECHNICAL MODULE SUBFACTOR ( $TMSF_{ST}$ )

A technical module subfactor can be calculated from the failure probability using Equation J-5.

### J.1.17 ADJUSTMENT TO TMSF FOR ON-LINE MONITORING FACTORS

Unexpected high corrosion rates, uneven heating, unexpected short-term over heating of the tubes, and flame impingement have the effect of increasing the life fraction

Table J-9—Guidelines for Determining the On-line Monitoring Factor

| On-Line Monitoring Method                            | Long Term Creep On-Line Monitoring Factor | Short Term Creep On-line Monitoring Factor |
|------------------------------------------------------|-------------------------------------------|--------------------------------------------|
| No monitoring                                        | 1.0                                       | 1.0                                        |
| Daily Visual and burner adjustment by operations     | 5                                         | 50                                         |
| Thermography                                         | 10                                        | 100                                        |
| Tube skin thermocouples and instrumentation to panel | 10                                        | 100                                        |

$$TMSF_{adjusted} = TMSF / \text{On-line Monitoring Factor}$$

consumed of the tubes. In addition to inspection, on-line monitoring of short-term upsets and over-firing conditions is commonly used to prevent premature tube failures. The advantage of on-line monitoring is that short-term changes in tube metal temperatures can be detected before periodic inspections. This detection permits a better estimate of the consumed life fraction and therefore estimated remaining life of the tubes. Various methods are employed including tube skin thermocouples, thermography, and a combination visual inspection and burner alignment. If on-line monitoring is employed, credit should be given to reflect a higher confidence in the predicted life fraction consumed. However, these methods have varying degrees of success depending on the type of furnace and tube materials. The adjustment factors suggested in Table J-9 assume problems found through on-line monitoring are corrected as a result of the findings.

### J.1.18 COMBINING LONG-TERM AND SHORT-TERM TECHNICAL MODULE SUBFACTOR (TMSF)

The furnace module *TMSF* should be taken as the larger of the short-term and long-term technical module subfactors.

#### References

1. API RP 530 *Recommended Practice for the Calculation of Heater-Tube Thickness in Petroleum Refineries*, 3rd Edition, American Petroleum Institute, 1988.
2. R. Viswanathan, *Damage Mechanisms and Life Assessment of High-Temperature Components*, ASM International, Metals Park, OH, 1989.

## J.2 Consequence Analysis

### J.2.1 INTRODUCTION

Consequence analysis for furnaces follows closely the methods presented in Section 7. The consequence measures presented in that section are intended as simplified methods for establishing relative priorities for inspection programs. If more accurate consequence estimates are needed, the analyst should refer to more rigorous analysis techniques, such as those used in Quantitative Risk Analysis.

### J.2.2 DETERMINING A REPRESENTATIVE FLUID AND ITS PROPERTIES

The scope of this Appendix is limited to furnaces that are used to heat liquid process streams. Furnaces such as steam/methane reformers are very much different, partly because the consequences of a leak are not usually very severe, except in the case of massive failures. (i.e., a furnace fired with methane used to heat methane is not severely affected by a tube leak releasing more fuel into the fire box.) For this reason, the representative fluids are the same as those presented in Section 7, except that  $C_1$ – $C_2$  material are not included.

Table J-10—List of Materials Modeled for Furnaces

| Representative Material | Examples of Applicable Materials         |
|-------------------------|------------------------------------------|
| $C_3$ – $C_5$           | Propane, butane, isooctane, pentane, LPG |
| $C_6$ – $C_8$           | Gasoline                                 |
| $C_9$ – $C_{12}$        | Diesel                                   |
| $C_{13}$ – $C_{16}$     | Jet fuel, kerosene                       |
| $C_{17}$ – $C_{25}$     | Gas oil, typical crude                   |
| $C_{25+}$               | Residuum, heavy crude                    |

### J.2.3 SELECTING A SET OF HOLE SIZES

The only hole sizes that practically need to be modeled for furnaces are 1 inch. holes and larger. Smaller holes are likely to produce leaks that are consumed within the fire box, and do not present a large potential for major damage. There may be some internal damage, such as damage to an adjacent tube due to flame impingement.

Table J-11—Hole Sizes Used in Furnaces RBI Analysis

| Hole Size | Range            | Representative Value    |
|-----------|------------------|-------------------------|
| Medium    | $1/4$ – 2 inches | 1 inch                  |
| Large     | 2 – 6 inches     | 4 inches                |
| Rupture   | $\geq 6$ inches  | Entire diameter of item |

Thus, furnace tubes can use the hole sizes: 1 inch, 4 inch, and rupture, provided the diameter of the leak is less than or equal to the diameter of the tube itself.

## J.2.4 ESTIMATING THE TOTAL AMOUNT OF FLUID AVAILABLE FOR RELEASE

To avoid generating results that are not credible for furnaces, the analyst must estimate the maximum amount of fluid that can be released from a furnace, then apply this maximum as an upper limit for consequence calculations. Since there are isolation valves between most furnaces and their attached vessels (from both directions), the maximum quantity released is suggested to be limited to the furnace inventory plus three minutes flow from both sources. If there are no isolation valves, or if there are only manual valves located close to the furnace, this total release inventory should be increased.

## J.2.5 ESTIMATING THE RELEASE RATE

For furnaces, it is considered that all releases will be of a continuous nature (although some may be of short duration). Also, the scope of this Appendix is limited to liquid releases. The release rate is calculated by methods in Section 7 for liquids.

## J.2.6 LIQUID DISCHARGE RATE CALCULATION

**J.2.6.1** Discharges of liquids through a sharp-edged orifice are described by the work of Bernoulli and Toricelli (Perry and Green, 1984)<sup>1</sup> and can be calculated as:

$$Q_L = C_d A \sqrt{2\rho - P} \frac{G_c}{144} \quad (\text{J-9})$$

where

$Q_L$  = liquid discharge rate (lb/sec),

$C_d$  = discharge coefficient,

$A$  = hole cross-sectional area (in<sup>2</sup>),

$\rho$  = density of liquid (lb/ft<sup>3</sup>),

$\Delta P$  = difference between upstream and atmospheric pressure (psid),

$g_c$  = conversion factor from lb<sub>f</sub> to lb<sub>m</sub>  
(32.2 lb<sub>m</sub>-ft / lb<sub>f</sub>-sec<sup>2</sup>).

**J.2.6.2** The discharge coefficient for fully turbulent flow from sharp-edged orifices is 0.60 to 0.64. A value of 0.61 is recommended for the RBI calculations. The above equation is used for both flashing and non-flashing liquids.

## J.2.7 DETERMINING THE TYPE OF RELEASE

For furnace incidents, all of the releases will be continuous in nature. There is no need to evaluate the instantaneous effects.

## J.2.8 DETERMINING THE FINAL PHASE OF THE FLUID

For the purposes of this Appendix, the methods for determining the final phase of the fluid after release from a furnace tube closely follows the methods outlined in Section 7. One exception is that gaseous initial fluid phases are not considered. In actual furnace tube failures, there is an increased tendency *initially* for a liquid fluid to vaporize upon leakage of the tube, due to the high temperatures in the fire box. However, in the event of a significant leak, the furnace quickly becomes fuel-rich in the fire box and the flame is either extinguished or greatly reduced. Subsequent flames occur where the released hydrocarbon can find sufficient oxygen to burn: at the top of the stack, and around air entry louvers or observation ports. Continued release of the hydrocarbon typically results in a liquid release from the bottom of the furnace with a pool fire.

Table J-12—Guidelines for Determining the Phase of a Fluid

| Phase of Fluid at Steady-State Operating Conditions | Phase of Fluid at Steady-State Ambient Conditions | Determination of Final Phase for Consequence Calculation                                                               |
|-----------------------------------------------------|---------------------------------------------------|------------------------------------------------------------------------------------------------------------------------|
| liquid                                              | gas                                               | Model as gas <i>unless</i> the fluid boiling point at ambient conditions is greater than 80°F, then model as a liquid. |
| liquid                                              | liquid                                            | Model as liquid.                                                                                                       |

## J.2.9 ADJUSTMENTS TO RELEASE MAGNITUDES FOR DETECTION, ISOLATION AND MITIGATION SYSTEMS

The adjustments to release characteristics based on detection, isolation and mitigation systems are provided in Table J-13. These values are based on engineering judgment, utilizing experience in evaluating mitigation measures in quantitative risk analyses.

## J.2.10 DETERMINING THE CONSEQUENCE AREA OF THE RELEASE

**J.2.10.1** Determination of the consequences of the release from a furnace tube failure is similar to the methods in Section 7, with the following important exceptions:

- Since there is a source of ignition in the fire box, the accumulation of a large (over 10,000 lb) cloud of vapor is not considered possible, thus VCEs are eliminated from consideration.
- Similarly, since furnace tube failures produce continuous type releases, rather than instantaneous releases, the possibilities of fireball or flash fire scenarios are also considered to be nil.

Table J-13—Adjustments to Flammable Consequences for Mitigation Systems

| Response System Ratings |           |                                    |
|-------------------------|-----------|------------------------------------|
| Detection               | Isolation | Consequence Adjustment             |
| A                       | A         | Reduce release rate or mass by 25% |
| A                       | B         | Reduce release rate or mass by 20% |
| A or B                  | C         | Reduce release rate or mass by 10% |
| B                       | B         | Reduce release rate or mass by 15% |
| C                       | C         | No adjustment to consequences      |

| Mitigation System                                                    | Consequence Adjustment             |
|----------------------------------------------------------------------|------------------------------------|
| Inventory, blowdown, coupled with isolation system rated B or higher | Reduce release rate or mass by 25% |
| Fire water deluge system and monitors                                | Reduce consequence area by 20%     |
| Fire water monitors only                                             | Reduce consequence area by 5%      |
| Foam spray system                                                    | Reduce consequence area by 15%     |

**J.2.10.2** Table J-14 represents the specific event outcomes expected for furnace tube releases. Note that jet fires are considered for lighter hydrocarbons. These are cases where most or all of the released fluid vaporizes and can exit from furnace openings with considerable force, resulting in a substantial flame affected area.

**J.2.10.3** Also in a manner analogous to the methods in Section 7, the affected area is calculated from Table 7-14. By definition, ignition is likely, and the release is of a continuous nature. There is an additional constraint placed on affected area calculation for furnaces: most furnaces have spill containment in the form of a curb at least 6 in. high and located approximately 10 ft from the outer perimeter of the furnace structure. This reduces the affected area of the release to the impoundment area. "Typical" impoundment areas are approximately 3000 ft<sup>2</sup>. If no containment exists, use the calculated affected area from the equations in Table J-15.

#### References

1. R. H. Perry, and D. Green, (editors) *Perry's Chemical Engineering Handbook*, 6th Edition, McGraw-Hill, New York, 1984.
2. TNO, *Methods for the Calculation of Physical Effects of the Escape of Dangerous Materials: Liquids and Gases*, Apeldoorn, The Netherlands, 1979.
3. AIChE/CCPS, *Guidelines for Use of Vapor Cloud Dispersion Models*, Center for Chemical Process Safety, American Institute of Chemical Engineers, New York, 1981.
4. F. Pasquill, *Atmospheric Diffusion: The Dispersion of Windborne Material from Industrial and Other Sources*, 2nd Edition, Wiley, New York, 1974.
5. DNV Technica, *User Manual for Process Hazard Analysis Software Tools (PHA-ST)*, Version 4.1, Temecula, California, 1993.
6. AIChE/CCPS (1989), *Guidelines for Chemical Process Quantitative Risk Analysis*, Center for Chemical Process Safety, American Institute of Chemical Engineers, New York.
7. Pope-Reid Associates, Inc., *Hazardous Waste Tank Failure (HWTf) and Release Model: Description of Methodology*, sponsored by Environmental Protection Agency, Office of Solid Waste, EPA/530/SW86/012, Interim draft report, Washington, D.C. 1986.
8. Robert C. Reid, et. al., *The Properties of Gases and Liquids*, 4th Edition, McGraw-Hill, New York, 1981.
9. Dow's *Fire and Explosion Index Hazard Classification Guide*, 7th Edition, American Institute of Chemical Engineers—AIChE Technical Manual, New York, 1994.

Table J-14—Specific Event Probabilities—Continuous Release Auto Ignition Likely<sup>a</sup><sup>a</sup>Liquids—Processed Above AIT

| Fluid                            | Probabilities of Outcomes |     |          |            |          |           |
|----------------------------------|---------------------------|-----|----------|------------|----------|-----------|
|                                  | Ignition                  | VCE | Fireball | Flash Fire | Jet Fire | Pool Fire |
| C <sub>3</sub> –C <sub>5</sub>   | 1                         |     |          |            | 1        |           |
| C <sub>6</sub> –C <sub>8</sub>   | 1                         |     |          |            | 1        |           |
| C <sub>9</sub> –C <sub>12</sub>  | 1                         |     |          |            | 1        |           |
| C <sub>13</sub> –C <sub>16</sub> | 1                         |     |          |            | 0.5      | 0.5       |
| C <sub>17</sub> –C <sub>25</sub> | 1                         |     |          |            | 0.5      | 0.5       |
| C <sub>25</sub> +                | 1                         |     |          |            |          |           |

Table J-15—Continuous Release Consequence Equations—Auto Ignition Likely<sup>1</sup>

| Material                         | Final Phase Gas                             |                                       | Final Phase Liquid                          |                                       |
|----------------------------------|---------------------------------------------|---------------------------------------|---------------------------------------------|---------------------------------------|
|                                  | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) | Area of Equipment Damage (ft <sup>2</sup> ) | Area of Fatalities (ft <sup>2</sup> ) |
| C <sub>3</sub> –C <sub>5</sub>   | $A = 0.1744 \times 330 x^{0.95}$            | $A = 0.1744 \times 847 x^{0.92}$      | $A = 0.1744 \times 470 x^{0.95}$            | $A = 0.1744 \times 1204 x^{0.92}$     |
| C <sub>6</sub> –C <sub>8</sub>   | $A = 0.1744 \times 367 x^{0.95}$            | $A = 0.1744 \times 921 x^{0.92}$      | $A = 0.1744 \times 525 x^{0.95}$            | $A = 0.1744 \times 1315 x^{0.92}$     |
| C <sub>9</sub> –C <sub>12</sub>  | $A = 0.1744 \times 391 x^{0.95}$            | $A = 0.1744 \times 981 x^{0.92}$      | $A = 0.1744 \times 560 x^{0.95}$            | $A = 0.1744 \times 1401 x^{0.92}$     |
| C <sub>13</sub> –C <sub>16</sub> |                                             |                                       | $A = 0.1744 \times 1023 x^{0.92}$           | $A = 0.1744 \times 2850 x^{0.90}$     |
| C <sub>17</sub> –C <sub>25</sub> |                                             |                                       | $A = 0.1744 \times 861 x^{0.92}$            | $A = 0.1744 \times 2420 x^{0.90}$     |
| C <sub>25</sub> +                |                                             |                                       | $A = 0.1744 \times 544 x^{0.90}$            | $A = 0.1744 \times 1604 x^{0.90}$     |

Note: Shaded area represents cases in which equations are nonapplicable.

 $x$  = total release rate, lb/sec. $A$  = area, ft<sup>2</sup>.<sup>1</sup>Must be processed at least 80°F above auto-ignition temperature.

## APPENDIX K—MECHANICAL FATIGUE (PIPING ONLY) TECHNICAL MODULE

### K.1 Scope

Fatigue failures of piping systems present a very real hazard under certain conditions. Properly designed and installed piping systems should not be subject to such failures, but prediction of vibration in piping systems at the design stage is very difficult, especially if there are mechanical sources of cyclic stresses such as reciprocating pumps and compressors. In addition, even if a piping system is not subject to mechanical fatigue in the as-built condition, changing conditions such as failure of pipe supports, increased vibration from out of balance machinery, chattering of relief valves during process upsets, changes in flow and pressure cycles or adding weight to unsupported branch connections (pendulum effect) can render a piping system susceptible to failure. Awareness of these influences incorporated into a management of change program can reduce the likelihood of failures. This module is intended to serve as an aid in this effort.

### K.2 Technical Module Screening Questions

The screening questions for the Piping Mechanical Fatigue Technical Module listed in Table K-1 are used to determine if the module should be entered.

### K.3 Basic Data

The data listed in Table K-2 is required for the Piping Mechanical Fatigue Technical Module.

### K.4 Basic Assumptions

**K.4.1** Properly designed piping has a low tendency for mechanical fatigue failure due to the low period of vibration or low stress amplitude. The period is determined by the piping diameter, thickness, mass, support spacing, and support type. Because the original analysis in the design stage may not predict with complete accuracy the response of the installed piping system, this module deals with those factors that are key indicators of a likelihood of failure.

**K.4.2** Based on input from plant engineers and inspectors from several disciplines, the following key indicators of a high likelihood of failure were identified:

- a. Previous failures due to fatigue.
- b. Audible, visible, or otherwise noticeable piping vibration (including small branch connections) that is greater than "typical" plant piping systems.
- c. Connection to reciprocating machinery, extreme cavitation through let-down or mixing valves, or relief valve chatter.

**K.4.3** The presence of any or all of the above indicators determines the base susceptibility, which is then modified by the other basic data. See Determination of the Technical Module Subfactor for details.

### K.5 Inspection Effectiveness

**K.5.1** As mentioned in the scope of this module, mechanical fatigue failures in piping are relatively rare. Unfortunately, when they do occur, they can be of high consequence, and more unfortunately, traditional non-destructive testing techniques are of little value in preventing such failures. The reason that crack detection techniques are not by themselves adequate are several:

- a. Most of the time to failure in piping fatigue is in the "initiation" phase, where a crack is in the process of forming or has formed but is so small that it is undetectable.
- b. By the time a crack has reached detectable size, the crack growth rate is high, and failure will likely occur in less than a typical inspection frequency.
- c. Cyclic stresses in vibrating piping tend to have a fairly high frequency, which increases the crack growth rate.
- d. Cracks form and grow in locations that are difficult to inspect, such as at fillet weld toes, the first unengaged thread root and defects in other welds.
- e. The initiation site for crack growth is not necessarily on the outside of the pipe, in fact, a crack can grow from an embedded defect undetectable from either side without special techniques.

**K.5.2** Therefore, inspection for mechanical fatigue in piping systems depends heavily on detection and correction of the conditions that lead to susceptibility. Such techniques include:

- a. Visual examination of pipe supports to assure that all supports are functioning properly (i.e., they are actually supporting the pipe).
- b. Visual examination of any cyclic motion of the pipe. If a pipe can be seen to be vibrating or moving in a cyclic manner, the pipe should be suspected of mechanical fatigue failure.
- c. Visual examination of all fillet welded supports and attachments to piping. Fillet welds are especially susceptible to failure by fatigue, and these may provide an early warning of problems if cracks or failures are found.
- d. As a general rule, small branch connections with unsupported valves or controllers on them are highly susceptible to failure. Examine these for signs of motion, and provide proper support for all such installations.

K-1

Table K-1—Screening Questions for Piping Mechanical Fatigue Technical Module

| Screening Questions                                                                                                                                                                                                                                                                                                                                                                                        | Action                                                             |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------|
| 1. Is this equipment item a pipe?                                                                                                                                                                                                                                                                                                                                                                          | If Yes, proceed to question #2.                                    |
| 2. Have there been past fatigue failures in this piping system <b>OR</b> is there visible/audible shaking in this piping system <b>OR</b> is there a source of cyclic vibration within approximately 50 feet and connected to the piping (directly or indirectly via structure). Shaking and source of shaking can be continuous or intermittent. Transient conditions often cause intermittent vibration. | If Yes, proceed to the Piping Mechanical Fatigue Technical Module. |

Table K-2—Basic Data Required for Analysis of Piping Mechanical Fatigue

| Basic Data                                                                                                                                                                        | Comments                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                 |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Number of Previous Fatigue Failures: None, One or > 1                                                                                                                             | If there has been no history of fatigue failures and there have been no significant changes, then the likelihood of a fatigue failure is believed to be low.                                                                                                                                                                                                                                                                                                                                                             |
| Severity of Vibration (audible or visible shaking): Minor, Moderate or Severe                                                                                                     | The severity of shaking can be measured in these subjective terms or can be measured as indicated at the bottom of this table in optional basic data.<br>Examples of shaking are:<br>Minor—no visible shaking, barely perceptible feeling of vibration when the pipe is touched.<br>Moderate—Little or no visible shaking, definite feeling of vibration when the pipe is touched.<br>Severe—Visible signs of shaking in pipe, branches, attachments, or supports. Severe feeling of vibration when the pipe is touched. |
| Number of weeks pipe has been shaking: 0 to 2 weeks, 2 to 13 weeks, 13 to 52 weeks.                                                                                               | If there have been no significant recent changes in the piping system and the amount of shaking has not changed for years, or the amount of accumulative cycles is greater than the endurance limit, then it can be assumed that the cyclic stresses are below the endurance limit. (Most piping shaking will be at a frequency greater than 1 hertz. One hertz for one year is approximately $3 \times 10^7$ cycles, well beyond the endurance limit for most construction materials.)                                  |
| Sources of cyclic stress in the vicinity of the item (e.g. within 50 ft): reciprocating machinery, RV chatter, high pressure drop valves (e.g., let-down and mixing valves), none | Determine to what cyclic source the piping is connected. The connections could be direct or indirect, e.g., through structural supports.                                                                                                                                                                                                                                                                                                                                                                                 |
| Corrective Actions taken: Modifications based on complete engineering analysis, Modifications based on experience, No Modifications                                               | Credit is given for analysis work which shows that the shaking piping is not a fatigue concern.                                                                                                                                                                                                                                                                                                                                                                                                                          |
| Piping Complexity: Based on 50 feet of pipe, choose:<br>0 to 5 branches, fittings, etc.<br>5 to 10 branches, fittings, etc.<br>> 10 branches, fittings, etc.                      | Determine the piping complexity in terms of the number of branched connections, number of fittings, etc.                                                                                                                                                                                                                                                                                                                                                                                                                 |
| Type of joint or branch design used in this piping: Threaded Socket Welded, Saddle on, Saddle in, "Weldolets", "Sweepolets                                                        | Determine the type of joint or branch connection that is predominant throughout this section of piping that is being evaluated.                                                                                                                                                                                                                                                                                                                                                                                          |
| Condition of the pipe: Missing/ Damaged Supports, Unsupported weights on branches, Broken gussets, Gussets/ supports welded directly to pipe, Good Condition                      | What is the condition of the piping section being evaluated in terms of support?                                                                                                                                                                                                                                                                                                                                                                                                                                         |



e. Manually feeling the pipe to detect vibration. This requires experience, but normally process plant piping will not vibrate any more severely than a car engine at idle speed.

f. Measurement of piping vibration using special monitoring equipment. There are no set values of vibration that will be acceptable or non acceptable under all conditions, so experience with using and interpreting vibration data is required.

g. Visual inspection of unit during transient conditions and different operating scenarios (e.g., startups, shutdowns, upsets, etc.) looking for intermittent vibrating conditions.

h. Checking for audible sounds of vibration emanating from piping components such as control valves and fittings.

## K.6 Determination of Technical Module Subfactor

The flow chart in Figure K-1 illustrates the logic for determining the technical module subfactor. The steps are outlined below:

Step 1. Determine the number of previous failures that have occurred, and apply a base susceptibility according to Table K-3:

Table K-3—Previous Fatigue Failures

| Previous Failures? | Base Susceptibility |
|--------------------|---------------------|
| None               | 1                   |
| One                | 50                  |
| >1                 | 500                 |

Step 2. Determine the amount of visible/audible shaking or audible noise occurring in the pipe, and apply a base susceptibility according to Table K-4:

Table K-4—Audible or Visual Shaking

| Audible or Visual Shaking? | Base Susceptibility |
|----------------------------|---------------------|
| Minor                      | 1                   |
| Moderate                   | 50                  |
| Severe                     | 500                 |

Step 2a. Adjust the base susceptibility due to audible or visible shaking by multiplying by the factors in Table K-5:

(This adjustment is based on observation that some piping systems may endure visible shaking for years. A repeated stress with a cycle of only 1 hertz (1/sec) results in over 30 million cycles in a year. Most systems, if they were subject to failure by mechanical fatigue would be expected to fail before

reaching tens or hundreds of million cycles. One should note that intermittent cycles are accumulative.)

Table K-5—Shaking Adjustment Factor

| Shaking Longer than X Weeks? | Adjustment Factor |
|------------------------------|-------------------|
| 0 to 2                       | 1                 |
| 2 to 13                      | 0.2               |
| 13 to 52                     | 0.02              |

Step 3. Determine the type of cyclic stress force connected directly or indirectly within approximately 50 feet of the pipe, and apply a base susceptibility according to Table K-6:

Table K-6—Type of Cyclic Force

| Source of Cyclic Force Connected Within 50 feet? | Base Susceptibility |
|--------------------------------------------------|---------------------|
| Reciprocating Machinery                          | 50                  |
| RV Chatter                                       | 25                  |
| Valve w/high pressure drop                       | 10                  |
| None                                             | 1                   |

Step 4. Select the maximum of the base susceptibilities from steps 1, 2, and 3 as the overall base susceptibility of the pipe to fatigue failure.

Step 5. Adjust the overall base susceptibility for any corrective actions taken by multiplying by the factors in Table K-7:

Table K-7—Corrective Action Taken

| Corrective Action taken:                            | Adjustment Factor: |
|-----------------------------------------------------|--------------------|
| Modification based on complete engineering analysis | 0.002              |
| Modification based on experience                    | 0.2                |
| No modifications                                    | 2                  |

Step 6: Adjust the overall base susceptibility for pipe complexity by multiplying by the factors in Table K-8:

Table K-8—Piping System Complexity

| Complexity, per 50 feet of pipe  | Adjustment Factor |
|----------------------------------|-------------------|
| 0 to 5 branches, fittings, etc.  | 0.5               |
| 5 to 10 branches, fittings, etc. | 1                 |
| > 10 branches, fittings, etc.    | 2                 |

Step 7. Adjust the overall base susceptibility for type of joint or branch design by multiplying by the factors in Table K-9:

Table K-9—Joint or Branch Design

| Joint Design  | Adjustment Factor |
|---------------|-------------------|
| Threaded      | 2                 |
| Socket Welded | 2                 |
| Saddle on     | 2                 |
| Saddle in     | 1                 |
| “Weldolets”   | 0.2               |
| “Sweepolets”  | 0.02              |

Step 8. Adjust the overall base susceptibility for pipe condition by multiplying by the factors in Table K-10:

Table K-10—Pipe Condition

| Condition                                | Adjustment Factor |
|------------------------------------------|-------------------|
| Missing/Damaged Supports                 | 2                 |
| Unsupported Weights                      | 2                 |
| Broken gussets                           | 2                 |
| Gussets/supports welded directly to pipe | 2                 |
| Good Condition                           | 1                 |

Step 9. Adjust the overall base susceptibility for small diameter branches by multiplying by the factors in Table K-11:

Table K-11—Branch Diameter

| Branch Size                  | Adjustment Factor |
|------------------------------|-------------------|
| Branches 2 in. or less       | 1                 |
| All Branches more than 2 in. | 0.02              |

Step 10. The value from step #9 is the final technical module subfactor for fatigue. This value is cut off at a maximum of 5000 for agreement with other TMSFs. (Values of 5000 or above indicate near certainty of failure.)

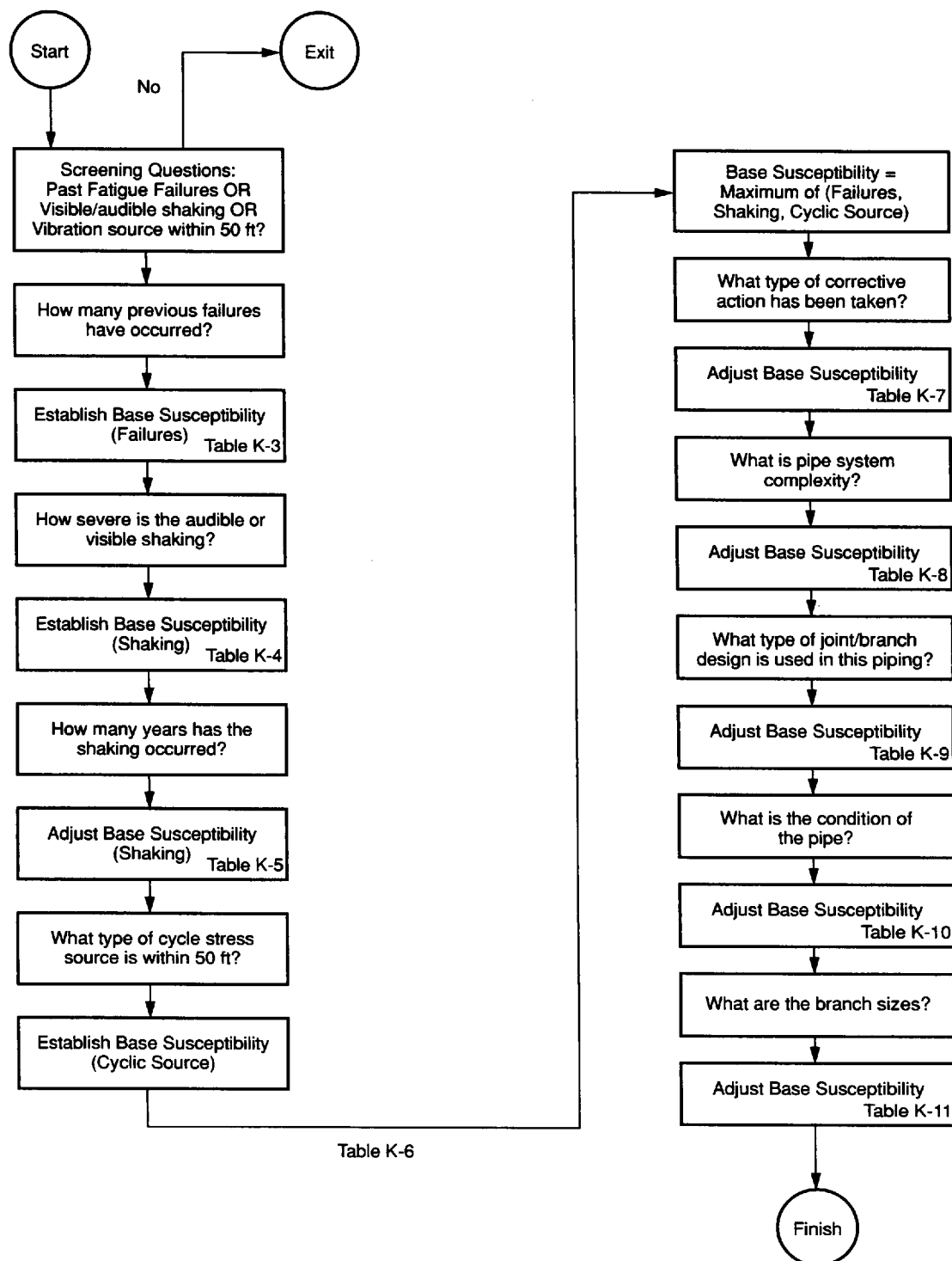


Figure K-1—Determining the Piping Mechanical Fatigue Technical Module Subfactor

## APPENDIX L—BRITTLE FRACTURE TECHNICAL MODULE

### L.1 Scope

This module establishes a technical module subfactor (likelihood of failure modifier) for process equipment subject to failure by brittle fracture. Low temperature/low toughness fracture, temper embrittlement, 885 degree embrittlement, and sigma phase embrittlement are within the scope of the module. Estimates of the susceptibility to specific brittle fracture mechanisms that can result in failure are included in this module. Expert advice may also be used to establish susceptibility to brittle fracture mechanisms.

### L.2 Technical Module Screening Questions

There are no screening questions to bypass this Technical Module. The screening questions are contained within the brittle fracture mechanisms included in this module.

### L.3 Basic Data

The basic data listed in Table L-1 are the minimum required to determine a technical module subfactor for brittle fracture. Additional data are required to answer the screening questions for the brittle fracture mechanisms listed in Table L-2. Further data required for each of the brittle fracture mechanisms are listed in the basic data table near the beginning of the section for each mechanism.

### L.4 Basic Assumptions

Brittle fracture requires the coincident presence of a sufficient size defect, application of sufficient stress, and a susceptible material. The susceptibility to failure by brittle fracture can change due to in-service conditions. The sections for each brittle fracture mechanism determine the likelihood adjustment (technical module subfactor) that is appropriate to each case.

Table L-1—Basic Data Required for Analysis of Brittle Fracture

| Basic Data                                       | Comments                                                                                                                                                                                                           |
|--------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Thickness, inches                                | Used to look up the required impact test temperature from ASME thickness criteria for impact testing.                                                                                                              |
| Operating Pressure, psig                         | Used to determine the applied stress.                                                                                                                                                                              |
| Operating Temperature, °F                        | Used to determine the susceptibility to various brittle fracture mechanisms.                                                                                                                                       |
| Material of Construction Specification and Grade | Used to look up the basic properties (Tensile strength, yield strength, etc.) for the equipment/piping. If known, the exact specification and grade should be used, otherwise, a conservative default can be used. |
| Post-weld Heat Treatment (Y/N)                   | Used to determine the residual stress in the equipment.                                                                                                                                                            |

Table L-2—Screening Questions for Brittle Fracture Mechanisms

| Screening Questions                                                                                                     | Action                                                |
|-------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------|
| 1. Low Temperature/Low Toughness Fracture                                                                               |                                                       |
| A. Is the material carbon or low alloy steel? See Table L-6 for listing.                                                | If Yes, proceed to Question B.                        |
| B. Do you know the MDMT?                                                                                                | If No, proceed to L.8, If yes, proceed to Question C. |
| C. Can the operating temperature under normal or upset conditions go below the Minimum Design Metal Temperature (MDMT)? |                                                       |
| 2. Temper Embrittlement                                                                                                 |                                                       |
| Is the material 1 1/4 Cr – 1/2 Mo, 2 1/4 Cr – 1/2 Mo, or 3 Cr – 1 Mo steel?                                             | If Yes to both, proceed to L-9                        |
| Is the operating temperature between 650°F and 1070°F?                                                                  |                                                       |
| 3. 885 Degree Embrittlement                                                                                             |                                                       |
| Is the material a high chromium (> 12%) ferritic steel?                                                                 | If Yes to both, proceed to L-10                       |
| Is the operating temperature between 700°F and 1050°F?                                                                  |                                                       |
| 4. Sigma Phase Embrittlement                                                                                            |                                                       |
| Is the material an austenitic stainless steel?                                                                          | If Yes to both, proceed to L-11                       |
| Is the operating temperature between 1100°F and 1700°F?                                                                 |                                                       |

## L.5 Determination of Technical Module Subfactor (*TMSF*)

A flow chart of the steps required determining the technical module subfactor are presented for each mechanism. These steps are discussed below, along with the required tables.

## L.6 Screening Questions for Brittle Fracture Mechanisms

The screening questions listed in Table L-2 are used to select the applicable brittle fracture mechanism.

## L.7 Determination of Susceptibility for Each Potential Brittle Fracture Mechanism

The individual sections for each brittle fracture mechanism will establish susceptibility for each of the mechanisms that are possible in this equipment.

## L.8 Low Temperature/Low Toughness Fracture

### L.8.1 DESCRIPTION OF DAMAGE

**L.8.1.1** Low temperature/low toughness fracture is the sudden failure of a structural component, usually initiated at a crack or defect. This is an unusual occurrence, because design stresses are normally low enough to prevent such an occurrence. However, some older equipment with thick walls, equipment that might see low temperatures due to an upset, or equipment that has been modified could be susceptible to varying degrees.

**L.8.1.2** Low temperature/low toughness fracture of steel is affected by:

- The applied loads. Fracture is less likely at low applied loads.
- The material specification. Some materials are manufactured to have good fracture properties or toughness properties. Materials are often "qualified" for use by performing an impact test. This test measures the energy needed to break a notched specimen.
- Temperature. Many materials (especially ferritic steels) become brittle below some temperature called the transition temperature. Brittle fracture is typically not a concern above 300°F.
- Residual stresses and post-weld heat treatment.
- Thickness.

**L.8.1.3** The goal of the low temperature/low toughness fracture assessment is to rank equipment with respect to their relative likelihood to failure with respect to fracture. This assessment will take into account the thickness, the material type, the post-weld heat treatment, and temperatures.

## L.8.2 BASIC DATA

The data listed in Table L-3, if available, can be used to estimate susceptibility of low temperature/low toughness fracture for carbon and low alloy steels. If exact process conditions are not known, contact a knowledgeable process engineer to obtain the best estimates.

## L.8.3 DETERMINATION OF TECHNICAL LOW TEMPERATURE/LOW TOUGHNESS MODULE SUBFACTOR

Figure L-2 outlines the process for determining the low temperature/low toughness subfactor.

Step 1. Determine if administrative or process controls exist that will prevent the equipment from being fully pressurized below some temperature. If so, use this temperature for  $T_{min}$  and go to Step 3.

Step 2. Determine the minimum temperature,  $T_{min}$ , which the equipment might experience. Use the lowest of the following:

- The minimum design temperature.
- The minimum temperature as estimated by the process engineer, including upsets.
- If the vessel or pipe is filled with a pressurized liquid, the boiling point of the liquid at atmospheric pressure. For example liquid ammonia has a boiling point of -28°F and propane has a boiling point of -40°F.

Step 3. Determine the metal thickness. Use the appropriate thickness per ASME UCS66.

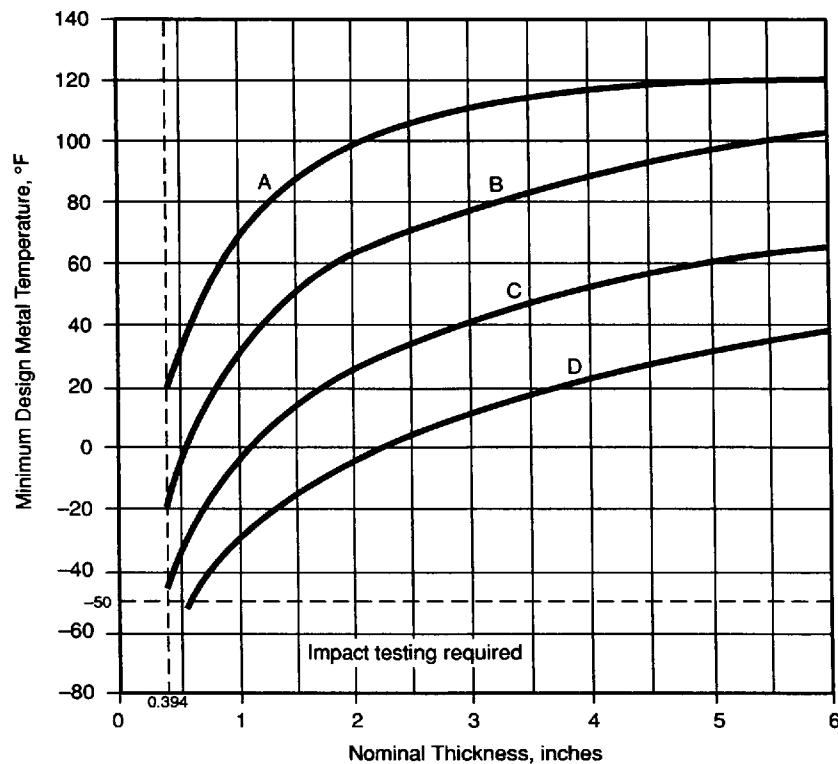
Step 4. Determine  $T_{ref}$ , either the temperature at which impact testing is known to have been performed, or the impact test exemption temperature for the material specification and grade. Use Table L-6 to find the exemption curve for the material specification and grade. If the material has been normalized, use the exemption curve for normalized material. Use the thickness and the curve identifier to determine the impact test exemption temperature from Figure L-1. One can also use the MDMT (Minimum Design Metal Temperature).

Step 5. Determine if the equipment has been post-weld heat treated. If not, use Table L-4, otherwise use Table L-5 for the technical module subfactor.

Step 6. Adjust for service experience. Per API RP 579 Level 2 Method 3 (Grandfathering), if equipment has been exposed for many years to the lowest expected temperature, the risk may be adjusted lower if the equipment is not in fatigue or SCC service. This is based on thousands of years of successful industry experience. Divide the technical module subfactor by 100.

Table L-3—Basic Data Required for Analysis of Low Temperature/Low Toughness Fracture

| Basic Data                                                         | Comments                                                                                                                                        |
|--------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------|
| Normalized (Y/N)                                                   | Used to look up the required impact test temperature.                                                                                           |
| Impact Test Temperature, °F                                        | If impact tested. If this is left blank, it will be assumed that impact tests were not done.                                                    |
| Administrative Controls for Upset Management (Y/N)                 | Are there controls and or awareness training to prevent the coincident occurrence of low temperatures (upset) at or near design pressures.      |
| Minimum Operating Temperature under Normal or Upset Conditions, °F | Can be entered by the user. The temperature may be set to the atmospheric boiling point of the fluid in the equipment if the fluid is a liquid. |



## Notes:

1. Curves A through D define material specification classes in accordance with Table L-6.
2. Equipment whose CET is above the appropriate material curve is exempt from further brittle fracture assessment.
3. This figure is identical to Figure UCS-66 of ASME Code Section VIII, Division 1.

Figure L-1—Impact Test Exemption Curves

Table L-4—Technical Module Subfactor for No Post-weld Heat Treatment

| NO PWHT       |      | Thickness, Inches |     |     |       |       |       |       |       |       |
|---------------|------|-------------------|-----|-----|-------|-------|-------|-------|-------|-------|
|               |      | 0.25              | 0.5 | 1.0 | 1.5   | 2.0   | 2.5   | 3.0   | 3.5   | 4.0   |
| $T - T_{ref}$ | 100  | 0.0               | 0.0 | 0.0 | 0.0   | 0.0   | 0     | 0.9   | 1.1   | 1.2   |
|               | 80   | 0.0               | 0.0 | 0.0 | 0.8   | 1.1   | 2     | 2     | 4     | 6     |
|               | 60   | 0.0               | 0.0 | 1.0 | 2     | 4     | 9     | 19    | 36    | 60    |
|               | 40   | 0.0               | 0.7 | 2   | 9     | 29    | 69    | 133   | 224   | 338   |
|               | 20   | 0.1               | 1.3 | 10  | 49    | 143   | 296   | 500   | 741   | 1,008 |
|               | 0    | 0.9               | 3   | 39  | 175   | 424   | 759   | 1,142 | 1,545 | 1,950 |
|               | -20  | 1.2               | 7   | 109 | 405   | 850   | 1,366 | 1,897 | 2,415 | 2,903 |
|               | -40  | 2                 | 16  | 220 | 697   | 1,317 | 1,969 | 2,596 | 3,176 | 3,703 |
|               | -60  | 2                 | 30  | 350 | 988   | 1,740 | 2,479 | 3,160 | 3,769 | 4,310 |
|               | -80  | 3                 | 46  | 474 | 1,239 | 2,080 | 2,873 | 3,581 | 4,203 | 4,746 |
|               | -100 | 4                 | 61  | 579 | 1,436 | 2,336 | 3,160 | 3,883 | 4,509 | 5,000 |

Table L-5—Technical Module Subfactor for Post-weld Heat Treatment

| PWHT          |      | Thickness, Inches |     |     |     |     |     |     |     |     |
|---------------|------|-------------------|-----|-----|-----|-----|-----|-----|-----|-----|
|               |      | 0.25              | 0.5 | 1.0 | 1.5 | 2.0 | 2.5 | 3.0 | 3.5 | 4.0 |
| $T - T_{ref}$ | 100  | 0.0               | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
|               | 80   | 0.0               | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 |
|               | 60   | 0.0               | 0.0 | 0.0 | 0.0 | 0.0 | 0.5 | 0.9 | 1.1 | 1.3 |
|               | 40   | 0.0               | 0.0 | 0.0 | 0.5 | 1.1 | 1.3 | 2   | 3   | 4   |
|               | 20   | 0.0               | 0.0 | 0.6 | 1.2 | 2   | 4   | 7   | 13  | 23  |
|               | 0    | 0.0               | 0.0 | 1.1 | 2   | 6   | 14  | 29  | 53  | 88  |
|               | -20  | 0.0               | 0.4 | 2   | 5   | 17  | 41  | 83  | 144 | 224 |
|               | -40  | 0.0               | 0.9 | 3   | 12  | 38  | 90  | 171 | 281 | 416 |
|               | -60  | 0.0               | 1.1 | 5   | 22  | 68  | 153 | 277 | 436 | 623 |
|               | -80  | 0.0               | 1.2 | 7   | 34  | 102 | 219 | 382 | 582 | 810 |
|               | -100 | 0.0               | 1.3 | 9   | 46  | 133 | 277 | 472 | 704 | 962 |

## L.8.4 INSPECTION EFFECTIVENESS

**L.8.4.1** Low temperature/low toughness fracture is prevented by a combination of appropriate design and operating procedures. When low temperature/low toughness fracture does occur, it almost invariably initiates at some pre-existing crack like defect. From the initiation point, a crack will grow quickly, resulting in a serious leak or sometimes complete rupture or separation of the equipment. Theoretically, an inspection to locate and remove such pre-existing defects would reduce the likelihood of failure. However, the initiating defect can be very small, and need not be exposed to the surface where it could be found. For this reason, inspection for such defects is generally not considered to be an effective method for prevention of brittle fracture.

**L.8.4.2** If existing records of an equipment item do not indicate if it is constructed of normalized plate, then a metallurgical examination may help resolve this. In some cases, it may be possible to remove samples of the material large enough for testing to determine the toughness, which can also improve the accuracy of the prediction of low temperature/low toughness fracture likelihood.

**L.8.4.3** As stated in L.8.4.1 and L.8.4.2, no "credit" is given for inspection. However, the results of metallurgical testing can be used to update the inputs to this Supplement, and may result in a change in the low temperature/low toughness fracture subfactor.

Table L-6—Carbon and Low Alloy Steels, and Impact Exemption Curves

| Specification.        | Default Curve | Normalized Curve |
|-----------------------|---------------|------------------|
| SA 36                 | A             | B                |
| SA-283 All Grades     | A             | B                |
| SA-285 All Grades     | B             | C                |
| SA-299                | A             | B                |
| SA-414 Gr A           | B             | C                |
| SA-414 Gr B,C,D,E,F,G | A             | B                |
| SA-442 Gr 55 & 60     | B             | D                |
| SA-455                | A             | B                |
| SA-515 Gr 55          | B             | C                |
| SA-515 Gr 60          | B             | C                |
| SA-515 Gr 65          | A             | B                |
| SA-515 Gr 70          | A             | B                |
| SA-516 Gr 55          | C             | D                |
| SA-516 Gr 60          | C             | D                |
| SA-516 Gr 65          | B             | C                |
| SA-516 Gr 70          | B             | C                |
| SA-537 All Grades     | D             | D                |
| SA-562                | A             | B                |
| SA-612                | B             | D                |
| SA-620 Gr 1           | A             | B                |
| SA-620 Gr 2           | A             | B                |
| SA-662 Gr A           | C             | D                |
| SA-662 Gr B           | B             | D                |
| SA-662 Gr C           | A             | D                |
| SA-737 Gr B & C       | A             | B                |
| SA-738 Gr A & B       | A             | B                |
| SA-812 Gr 65 & 80     | A             | B                |
| SA-202 Gr A & B       | A             | A                |
| SA-203 All Grades     | D             | D                |
| SA-204 All Grades     | A             | A                |
| SA-225 Gr C           | A             | A                |
| SA-302 Gr A           | A             | A                |
| SA-302 Gr B           | A             | A                |
| SA-302 Gr C           | C             | C                |
| SA-302 Gr D           | D             | D                |
| SA-387 Gr 2 Cl.1      | A             | A                |
| SA-387 Gr 2 Cl.2      | A             | A                |
| SA-387 Gr 12 Cl.1     | A             | A                |
| SA-387 Gr 12 Cl.2     | A             | A                |



Table L-6—Carbon and Low Alloy Steels, and Impact Exemption Curves (Continued)

| Specification.         | Default Curve | Normalized Curve |
|------------------------|---------------|------------------|
| SA-387 Gr 11 Cl.1      | A             | A                |
| SA-387 Gr 11 Cl.2      | A             | A                |
| SA-387 Gr 22 Cl.1      | A             | C                |
| SA-387 Gr 22 Cl.2      | A             | C                |
| SA-387 Gr 21 Cl.1      | A             | C                |
| SA-387 Gr 21 Cl.2      | A             | C                |
| SA-387 Gr 5 Cl.1       | A             | A                |
| SA-387 Gr 5 Cl.2       | A             | A                |
| SA-387 Gr 91 Cl.2      | A             | A                |
| SA-533 Gr A, Cl.1      | A             | A                |
| SA-533 Gr B, Cl.1      | B             | B                |
| SA-533 Gr C, Cl.1      | C             | C                |
| SA-542 Gr C Cl.4a      | A             | A                |
| SA-832                 | A             | A                |
| SA-53 pipe Gr A & B    | A             | A                |
| SA-106 pipe All Grades | A             | A                |
| SA-179 tube            | A             | A                |
| SA-192 tube            | A             | A                |
| SA-210 tube Gr A-1 & C | A             | A                |
| SA-333 pipe Gr 1 & 6   | A             | A                |
| SA-334 tube Gr 1 & 6   | A             | A                |
| SA-524 pipe Gr I & II  | D             | D                |
| SA-556 tube All Grades | A             | A                |
| SA-135 pipe Gr A & B   | A             | A                |
| SA-178 tube Gr A & C   | A             | A                |
| SA-214 tube            | A             | A                |
| SA-226 tube            | A             | A                |
| SA-557 tube All Grades | A             | A                |
| SA-587 tube            | A             | A                |
| Unknown                | A             | B                |

**References:**

1. ASME *Boiler and Pressure Vessel Code*, Section VIII.
2. ASME *Boiler and Pressure Vessel Code*, Section XI.
3. API RP 579 *Fitness-For-Service*.

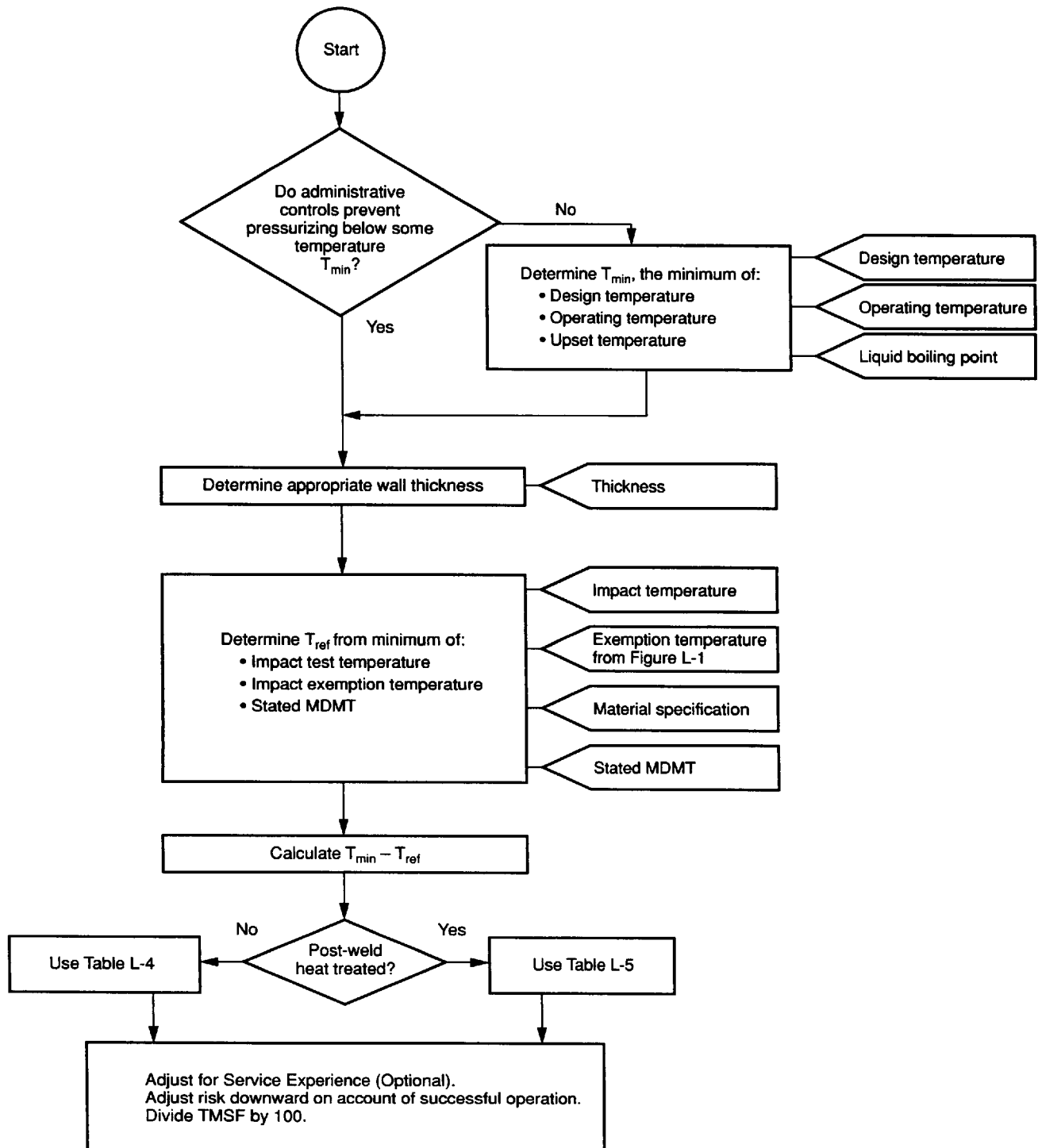


Figure L-2—Determination of Technical Module Subfactors for Low Temperature/Low Toughness Fracture

## L.9 Temper Embrittlement

### L.9.1 DESCRIPTION OF DAMAGE

**L.9.1.1** The toughness of many steels is reduced by a phenomenon called "temper embrittlement" after extended exposure to temperatures in the range of 650°F to 1070°F. Of particular interest to the refining and petrochemical industries is the embrittlement of Cr-Mo steels used in operations within the temperature range for embrittlement. The reduction in fracture toughness only affects the material at the lower temperatures experienced during startup and shutdown of equipment. Industry practice to avoid brittle fracture has been to reduce the operating pressure to one-fourth of the design pressure when the vessel temperature is less than some minimum process temperature. Typical industry practice for this minimum temperature is 300°F to 350°F for older low alloy steels, or lower temperatures for more modern steels.

**L.9.1.2** Temper embrittlement is caused by segregation of tramp elements and alloying elements along grain boundaries in the steel. The phosphorous and tin content of the steel are of particular importance, and their effect is made worse by manganese and silicon, which are important alloying elements. A "J" factor based on composition is typically specified to control the susceptibility to temper embrittlement. The "J" factor is calculated from the following equation:  $(J = (Si + Mn) \times (P + Sn) \times 104)$ . Laboratory and long-term field studies have confirmed fair correlation between the "J" factor and the amount of temper embrittlement.

**L.9.1.3** One very important aspect of temper embrittlement is the tendency of weld metal and heat affected zones to show increased susceptibility to embrittlement vs. the wrought base material. A few studies have shown that 2 $\frac{1}{4}$  Cr – 1 $\frac{1}{2}$  Mo and 3 Cr – 1 Mo are particularly susceptible. It is debatable whether or not 1 $\frac{1}{4}$  Cr – 1 $\frac{1}{2}$  Mo steels are also susceptible, but for the purposes of this module, they will be included.

### L.9.2 TEMPER EMBRITTLEMENT SCREENING QUESTIONS

The screening questions for temper embrittlement listed in Table L-7 are used to determine if the section on temper embrittlement should be used.

Table L-7—Screening Questions for Temper Embrittlement

| Screening Questions                                                                                                        | Action                             |
|----------------------------------------------------------------------------------------------------------------------------|------------------------------------|
| 1. Is the material 1 $\frac{1}{4}$ Cr – 1 $\frac{1}{2}$ Mo, 2 $\frac{1}{4}$ Cr – 1 $\frac{1}{2}$ Mo, or 3 Cr – 1 Mo steel? | If Yes to both, proceed to L.10.4. |
| 2. Is the operating temperature between 650°F and 1070°F?                                                                  |                                    |

### L.9.3 BASIC DATA

The data listed in Table L-8, are used to estimate susceptibility of temper embrittlement for carbon and low alloy steels. If exact process conditions are not known, contact a knowledgeable process engineer to obtain the data.

Table L-8—Basic Data Required for Analysis of Temper Embrittlement

| Basic Data                                                                            | Comments                                                                                                                                                                                                                                                                   |
|---------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Normalized (Y/N)                                                                      | Used to look up the required impact test temperature.                                                                                                                                                                                                                      |
| Impact Test Temperature, °F                                                           | If impact tested. If this is left blank, it will be assumed that impact tests were not done.                                                                                                                                                                               |
| Administrative Controls for Upset Management (Y/N)                                    | Are there controls or awareness training to prevent the coincident occurrence of low temperatures (upset) at or near design pressures.                                                                                                                                     |
| Minimum Operating Temperature under Normal, Startup/Shutdown, or Upset Conditions, °F | For temper embrittlement, this may be the temperature below which the operating pressure is reduced for purposes of fracture control. If not entered, the temperature will be set to the atmospheric boiling point of the fluid in the equipment if the fluid is a liquid. |
| Time in Service, Years                                                                | The number of years in service within the temperature range                                                                                                                                                                                                                |
| $\Delta$ FATT ( $\Delta$ Fracture Appearance Transition Temperature), °F              | Provided by the Supplement based on the material type, metallurgical condition, operating temperature and time in service. The user may override this value if better information is available.                                                                            |
| Chemical Composition of Steel (optional)                                              | Specifically, the %Si, %Mn, %P, and %Sn which contribute to the susceptibility to temper embrittlement. If not known, a transition shift will be assumed.                                                                                                                  |
| Screening of Materials (Y/N)                                                          | Was the material used for the equipment "screened" for susceptibility to temper embrittlement by such methods as specifications for steel composition, or specification of a transition temperature requirement in a "step cooling embrittlement" (SCE) test.              |
| SCE Specified Delta Temperature, °F                                                   | The delta temperature specified for step cooling embrittlement (SCE) tests.                                                                                                                                                                                                |

### L.9.4 BASIC ASSUMPTIONS

Table L-9 lists some common materials that are known to be susceptible to temper embrittlement.

Table L-9—Materials Susceptible to Temper Embrittlement

| Specification     | Default Curve | Normalized Curve |
|-------------------|---------------|------------------|
| SA-387 Gr 11 Cl.1 | A             | A                |
| SA-387 Gr 11 Cl.2 | A             | A                |
| SA-387 Gr 22 Cl.1 | A             | C                |
| SA-387 Gr 22 Cl.2 | A             | C                |
| SA-387 Gr 21 Cl.1 | A             | C                |
| SA-387 Gr 21 Cl.2 | A             | C                |
| Not Listed        | A             | A                |

### L.9.5 DETERMINATION OF TEMPER EMBRITTLEMENT TECHNICAL MODULE SUBFACTOR

Figure L-3 outlines the process for determining the subfactor for temper embrittlement.

Step 1. Determine if administrative or process controls exist that will prevent the equipment from being fully pressurized below some temperature. If so, use this temperature for  $T_{min}$  and go to Step 3.

Step 2. Determine the minimum temperature,  $T_{min}$ , which the equipment might experience. Use the lowest of the following:

- The minimum design temperature.
- The minimum temperature as estimated by the process engineer, including upsets.

Step 3. Determine the metal thickness. Use the appropriate thickness per ASME UCS66.

Step 4. Determine  $T_{ref}$ , either the temperature at which impact testing is known to have been performed, or the impact test exemption temperature for the material specification and grade. Use Table L-9 to find the exemption curve for the material specification and grade. If the material has been normalized, use the exemption curve for normalized material. Use the thickness and the curve identifier to determine the impact test exemption temperature from Figure L-1. One can also use the MDMT (minimum design metal temperature).

Step 5. Add  $\Delta FATT$  to  $T_{ref}$ .

The  $\Delta FATT$  can be estimated by the following methods, listed in approximate decreasing order of accuracy:

- Enter the  $\Delta FATT$  directly as determined by engineering analysis or actual testing of metal samples.

- Enter the value specified for the allowable  $\Delta FATT$  determined in a step cooling embrittlement (SCE) test. This can be related to the actual in-service  $\Delta FATT$  based on the operating hours using the equation [ $\Delta FATT = 0.67 \times (\log(t - 0.91) \times SCE)$ ] (L.1) where  $t$  is the operating time in hours, and SCE is the specified change in FATT.

- Use the chemical composition (if not known) to determine the "J-factor" that can be correlated to the expected  $\Delta FATT$  after long-term service. Based on long term exposures, this is conservatively correlated to the J-factor approximately by the following equation: [ $\Delta FATT = 0.6 \times J - 20$ ] (L.2).

- A conservative value of 150°F can be assumed for the long term  $\Delta FATT$ .

Step 6. Determine if the equipment has been post-weld heat treated. If not, use Table L-4, otherwise use Table L-5 for the technical module subfactor.

#### References:

- Viswanathan, R., *Damage Mechanisms and Life Assessment of High Temperature Components*, ASM International, 1989.
- The Materials Properties Council, Inc., Meeting on MPC/API Task Group on Materials for Pressure Vessel Service with Hydrogen at High Temperatures and Pressures, HPV-51, Oct. 1990, Minutes.
- T. Iwodate, J. Watanabe, Y. Tanaka; Prediction of the Remaining Life of High-Temperature/Pressure Reactors Made of Cr-Mo Steels, Trans. of ASME, Vol.107, p230, Aug.1985
- T. Iwodate; Prediction of the Remaining Life of High-temperature/Pressure Reactors made of Cr-Mo Steels, Maroran Research Laboratory, The Japan Steel Works Ltd., March 1989.
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- W. Erwin & J. Kerr; *The Use of Quenched and tempered 2 1/4 Cr-1 Mo steel For Thick Wall Reactor Vessel in Petroleum Refinery Processes: An Interpretive Review of 25 Years of Research and Application*, Bulletin 275, ISSN 0034-2326, Welding Research Council, New York, Feb 1982.
- J. Barsom & S. Rolfe; *Correlation Between KIC and Charpy V-Notch Test Results in the Transition Temperature Range*, ASTM STP 466, Vol.2, No.4, 1970.

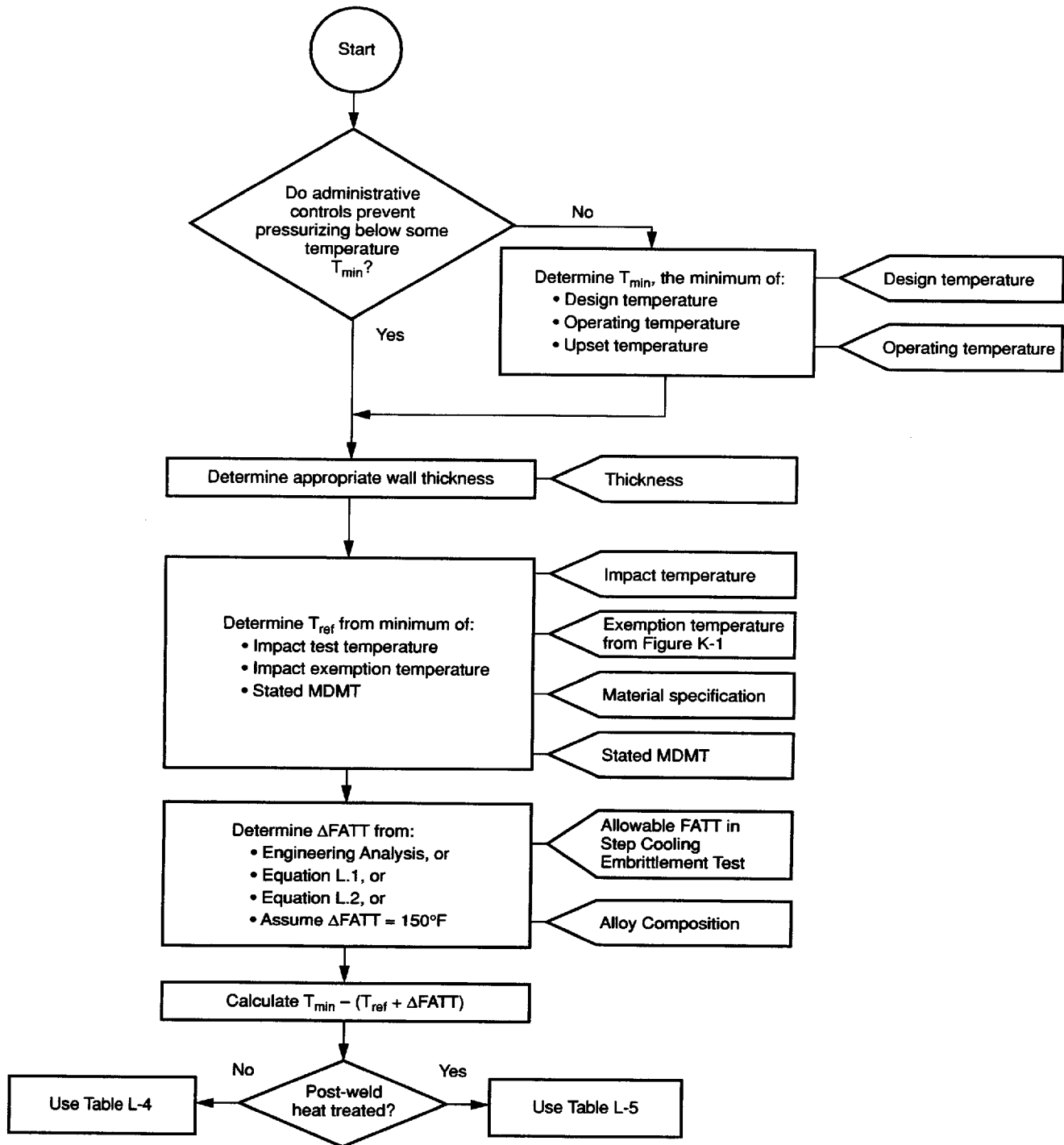


Figure L-3—Determination of Technical Module Subfactors for Temper Embrittlement

## L.10 885°F Embrittlement

### L.10.1 DESCRIPTION OF DAMAGE

**L.10.1.1** 885°F embrittlement is a reduction in toughness of ferritic stainless steels with a chromium content of greater than 13%, after exposure to temperatures between 700°F and 1000°F. The reduction in toughness is due to precipitation of a chromium—phosphorous intermetallic phase at elevated temperatures. As is the case with other mechanisms that result in a loss of toughness due to metallurgical changes, the effect on toughness is most pronounced not at the operating temperature, but at lower temperatures experienced during plant shutdowns or upsets.

**L.10.1.2** The precipitation of the intermetallic phase is believed to occur most readily at a temperature around 885°F, hence the name for this mechanism. Steels with more than 27% chromium are most severely affected, but these are not typically used in refinery or petrochemical processes. Martensitic stainless steels such as Type 410 are normally considered to be immune to this problem. Type 405 is a ferritic stainless steel that is subject to the problem if it contains chromium levels at the high end of its composition range.

**L.10.1.3** The existence of 885°F embrittlement can reveal itself by an increase in hardness in affected areas. Physical testing of samples removed from service is the most positive indicator of a problem.

**L.10.1.4** 885°F embrittlement is reversible by appropriate heat treatment to dissolve precipitates, followed by rapid cooling. Heat treatment temperature is typically in the range of 1400°F to 1500°F, so this may not be practical for many equipment items.

### L.10.2 885°F EMBRITTLEMENT SCREENING QUESTIONS

The screening questions for 885°F embrittlement listed in Table L-10 are used to determine if the section on 885°F embrittlement fracture should be used.

Table L-10—Screening Questions for 885°F Embrittlement

| Screening Questions                                                                    | Action                             |
|----------------------------------------------------------------------------------------|------------------------------------|
| 1. Is the material a high chromium (> 13%) ferritic steel? See Table L-12 for listing. | If Yes to both, proceed to L.11.3. |
| 2. Is the operating temperature between 700°F and 1050°F?                              |                                    |

### L.10.3 BASIC DATA

The data listed in Table L-11, if available, can be used to estimate susceptibility to 885°F embrittlement. If exact process conditions are not known, contact a knowledgeable pro-

Table L-11—Basic Data Required for Analysis of 885°F Embrittlement

| Basic Data                                                         | Comments                                                                                                                                   |
|--------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------|
| Administrative Controls for Upset Management (Y/N)                 | Are there controls and or awareness training to prevent the coincident occurrence of low temperatures (upset) at or near design pressures. |
| Minimum Operating Temperature under Normal or Upset Conditions, °F | To be entered by the user.                                                                                                                 |
| Original Transition Temperature, °F                                | $T_{ref}$ to be used in the module. If this is not available, a transition temperature of 80°F can be used.                                |

### L.10.4 BASIC ASSUMPTIONS

**L.10.4.1** Since 885°F can occur in a relatively short period of time. It is assumed in this module that any of the ferritic materials listed in Table L-12 that have been exposed to temperatures in the 700°F to 1000°F range are affected.

Table L-12—Materials Affected by 885°F Embrittlement

| Steel Common Designation | % Chromium   |
|--------------------------|--------------|
| Type 405                 | 11.5 – 14.5% |
| Type 430                 | 16 – 18%     |
| Type 430F                | 16 – 18%     |
| Type 442                 | 18 – 23%     |
| Type 446                 | 23 – 27%     |

**L.10.4.2** RP 579 recommends that for embrittled materials, the toughness should be determined by the  $K_{Ic}$  (fracture arrest) curves, truncated at 100°F. It is further recommended that for severely embrittled materials, 50% of this value should be used. Ductile-to-brittle transition temperatures for ferritic stainless steels (400 series) fall in the 50°F to 100°F range. For the purposes of this module, a  $T_{ref}$  of 80°F will be used, unless overridden by the user. Figure L-4 shows the  $K_{Ic}$  and  $K_{Ic}$  curves for comparison.

### L.10.5 DETERMINATION OF 885°F EMBRITTLEMENT TECHNICAL MODULE SUBFACTOR

Figure L-5 outlines the process for determining the technical module subfactor.

Step 1. Determine if administrative or process controls exist that will prevent the equipment from being fully pressurized below some temperature. If so, use this temperature for  $T_{min}$  and go to Step 3.

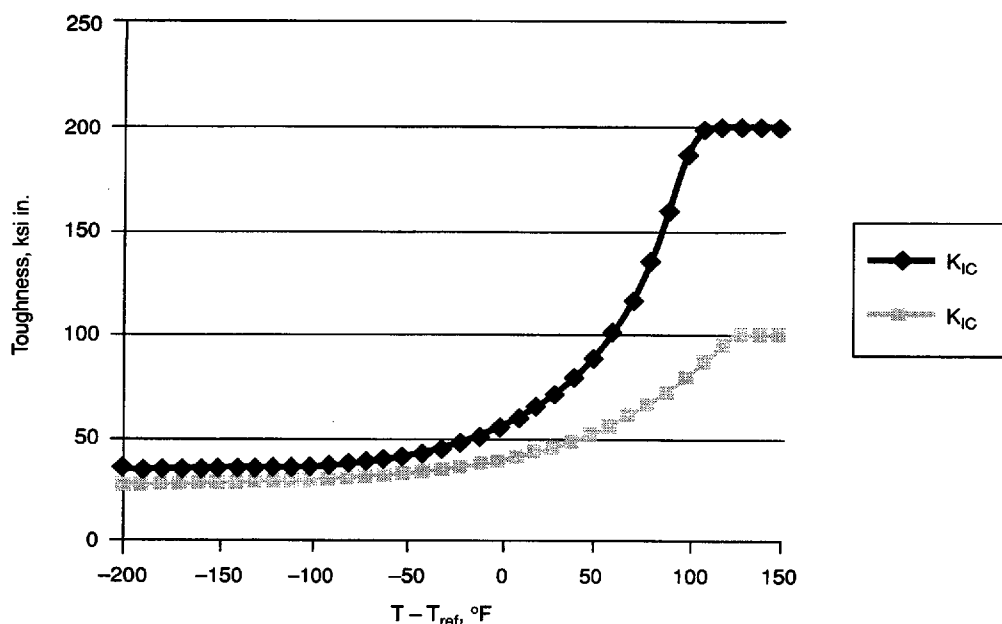


Figure L-4—Fracture Arrest Curves

Step 2. Determine the minimum temperature,  $T_{min}$ , that the equipment might experience. Use the lowest of the following:

- The minimum design temperature.
- The minimum temperature as estimated by the process engineer, including upsets.

Step 3. Determine  $T_{ref}$ , either using a default value of 80°F, or other value of the original transition temperature, if known.

Step 4. Look up the technical module subfactor from Table L-13.

Table L-13—885°F Embrittlement Technical Module Subfactor

| $T_{min} - T_{ref}$ | TMSF  |
|---------------------|-------|
| 100                 | 2     |
| 80                  | 8     |
| 60                  | 30    |
| 40                  | 87    |
| 20                  | 200   |
| 0                   | 371   |
| -20                 | 581   |
| -40                 | 806   |
| -60                 | 1,022 |
| -80                 | 1,216 |
| -100                | 1,381 |

#### References:

1. Timmins, P. F., *Predictive Corrosion and Failure Control in Process Operations*, ASM International, 1996
2. API RP 579 *Fitness-For-Service*.
3. Holt J. M., Mindlin H., and Ho C. Y., *Structural Alloys Handbook*, 1994 Edition, Purdue University, West Lafayette, IN.

## L.11 Sigma Phase Embrittlement

### L.11.1 DESCRIPTION OF DAMAGE

**L.11.1.1** Sigma phase is a hard, brittle intermetallic compound of iron and chromium with an approximate composition of  $Fe_{0.6}Cr_{0.4}$ . It occurs in ferritic (Fe-Cr), martensitic (Fe-Cr), and austenitic (Fe-Cr-Ni) stainless steels when exposed to temperatures in the range of 1100°F to 1700°F. The rate of formation and the amount of sigma formed are dependent on chemical composition of the alloy and prior cold work history. Ferrite stabilizers (Cr, Si, Mo, Al, W, V, Ti, Nb) tend to promote sigma formation, while austenite stabilizers (C, Ni, N, Mn) tend to retard sigma formation. Austenitic stainless steel alloys typically exhibit a maximum of about 10% sigma phase, or less with increasing nickel. However, other alloys with a nominal composition of 60% Fe, 40% Cr (about the composition of sigma) can be transformed to essentially 100% sigma. A transformation vs. time curve for such a Fe-Cr

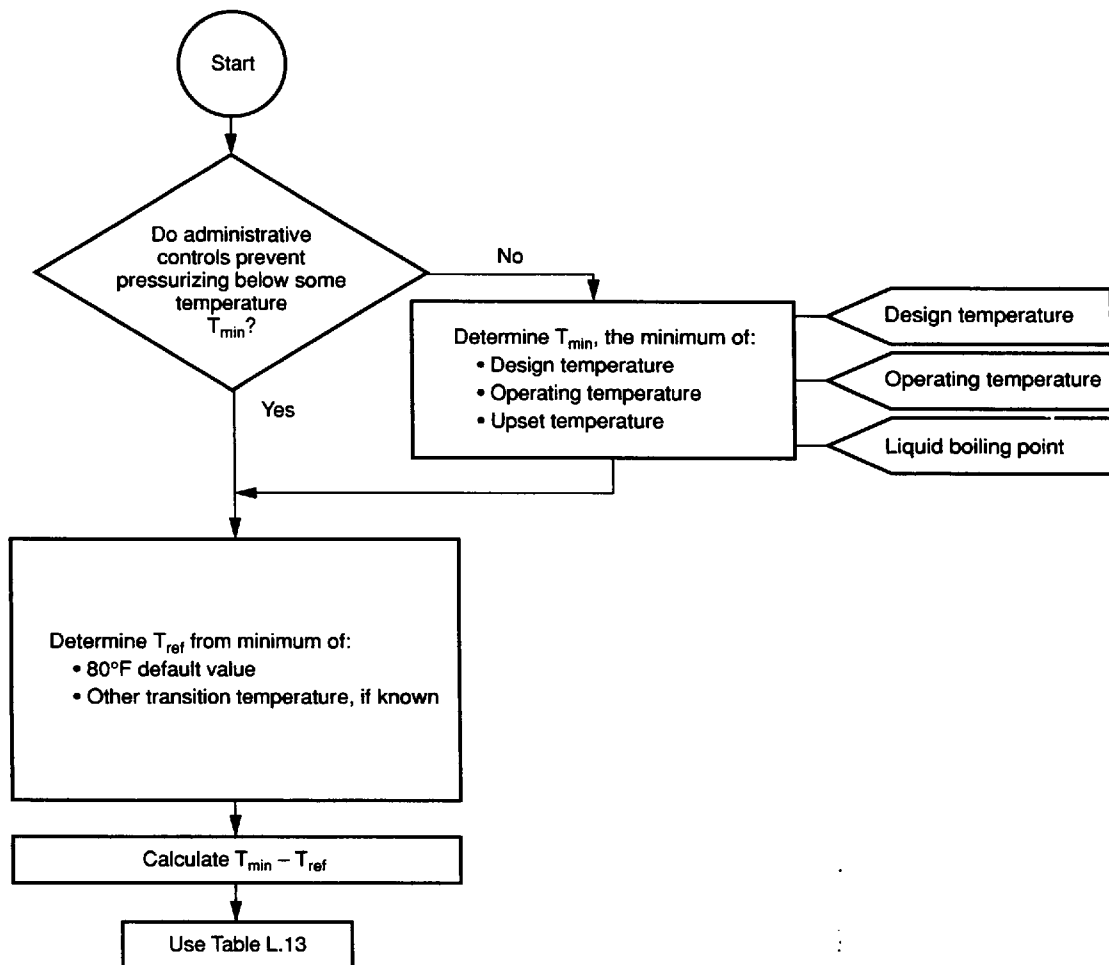


Figure L-5—Determination of Technical Module Subfactors for 885°F Embrittlement

alloy showed 100% conversion to sigma in 3 hours at 1377°F. Conversion to sigma in austenitic stainless steels can also occur in a few hours, as evidenced by the known tendency for sigma to form if an austenitic stainless steel is subjected to a post-weld heat treatment at 1275°F. Sigma is unstable at temperatures above 1650°F, and austenitic stainless steel components can be de-sigmatized by solution annealing at 1950°F for four hours followed by a water quench.

**L.11.1.2** Mechanical properties of sigmatized materials are affected depending upon both the amount of sigma present and the size and shape of the sigma particles. For this reason, prediction of mechanical properties of sigmatized material is difficult.

**L.11.1.3** The tensile and yield strength of sigmatized stainless steels increases slightly compared with solution annealed material. This increase in strength is accompanied by a reduc-

tion in ductility (measured by % elongation and reduction in area) and a slight increase in hardness.

**L.11.1.4** The property that is most affected by sigma formation is the toughness. Impact tests show decreased impact energy absorption, and decreased percent shear fracture of sigmatized stainless steels vs. solution annealed material. The effect is most pronounced at temperatures below 1000°F, although there may be some reduction in impact properties at higher temperatures as well. However, because austenitic stainless steels exhibit such good impact properties in the solution annealed condition, then even with considerable degradation, the impact properties may be comparable to other steels used in the process industries. A draft fitness-for-service report from the Materials Properties Council recommends default fracture toughness values of  $150 \text{ ksi}\sqrt{\text{in}}$  and  $80 \text{ ksi}\sqrt{\text{in}}$  for base metal and weld metal, respectively, for thermally embrittled austenitic stainless steels.



**L.11.1.5** Tests performed on sigmatized stainless steel samples from FCC regenerator internals showed that even with 10% sigma formation, the charpy impact toughness was 39 ft-lbs at 1200°F. This would be considered adequate for most steels, but is much less than the 190 ft-lbs obtained for solution annealed stainless steel. In this specimen, the impact toughness was reduced to 13 ft-lbs at room temperature, a marginal figure but still acceptable for many applications. The percent of shear fracture is another indicator of material toughness, indicating what percent of the charpy impact specimen broke in a ductile fashion. For the 10% sigmatized specimen referenced above, the values ranged from 0% at room temperature to 100% at 1200°F. Thus, although the impact toughness is reduced at high temperature, the specimens broke in a 100% ductile fashion, indicating that the material is still suitable. The lack of fracture ductility at room temperature indicates that care should be taken to avoid application of high stresses to sigmatized materials during shutdown, as a brittle fracture could result. Figure L-6 summarizes impact property data found for 304 and 321 stainless steels.

### L.11.2 SIGMA PHASE EMBRITTLEMENT SCREENING QUESTIONS

The screening questions for sigma phase embrittlement listed in Table L-14 are used to determine if the module for sigma phase embrittlement should be entered.

Table L-14—Screening Questions for Sigma Phase Embrittlement

| Screening Questions                                       | Action                            |
|-----------------------------------------------------------|-----------------------------------|
| 1. Is the material an austenitic stainless steel?         | If Yes to both, proceed to L.11.3 |
| 2. Is the operating temperature between 1100 and 1700 °F? |                                   |

### L.11.3 BASIC DATA

The data listed in Table L-15, if available, can be used to estimate susceptibility to sigma phase embrittlement. If exact process conditions are not known, contact a knowledgeable process engineer to obtain the best estimates.

Table L-15—Basic Data Required for Analysis of Sigma Phase Embrittlement

| Basic Data                                                                                | Comments                                                                                                                                   |
|-------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------|
| Administrative Controls for Upset Management (Y/N)                                        | Are there controls and/or awareness training to prevent the coincident occurrence of low temperatures (upset) at or near design pressures. |
| Evaluation Temperature under Normal, Upset, or Shutdown Conditions                        | To be entered by the user.                                                                                                                 |
| Amount of Sigma (estimate)<br>Low (> 1%, < 5%),<br>Medium (≥ 5%, < 10%),<br>High (≥ 10%). | User input.                                                                                                                                |

### L.11.4 BASIC ASSUMPTIONS

Since data is scarce and exhibits considerable scatter, it is assumed that sigmatized austenitic stainless steels will behave in a brittle fashion similar to ferritic steels. The data available showed a reduction in properties, but not the original properties. For this module it is assumed that the original impact toughness of austenitic stainless steels is about 300 ksi  $\sqrt{\text{in}}$ .

The trends of properties vs. % sigma and temperature are shown in Figure L-6. The references were searched for additional test data, which was scarce and exhibited considerable scatter. The test data found is listed in Table L-16:

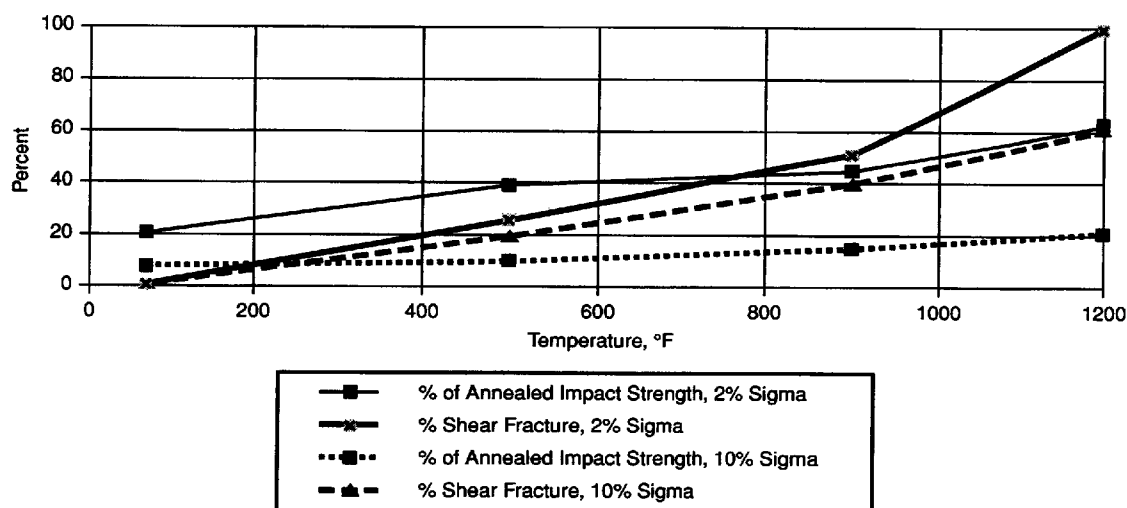


Figure L-6—Impact Properties of Sigmatized Stainless vs. 304 SS, 2% Sigma / 321 SS, 10% Sigma

Table L-16—Data for Property Trends of Toughness vs. Temperature

| Test Temperature | 304 SS<br>2% Sigma |         | 321 SS<br>10% Sigma |         | 304 SS<br>1% Sigma |         | 304 SS<br>2% Sigma |         | 347 SS<br>1% Sigma |         |
|------------------|--------------------|---------|---------------------|---------|--------------------|---------|--------------------|---------|--------------------|---------|
|                  | % of Impact        | % Shear | % of Impact         | % Shear | % of Impact        | % Shear | % of Impact        | % Shear | % of Impact        | % Shear |
| 70               | 21                 | 0       | 7                   | 0       | —                  | —       | 21                 | 10      | 50                 | 90      |
| 500              | 38                 | 25      | 10                  | 20      | —                  | —       | —                  | —       | 100                | 100     |
| 900              | 44                 | 50      | 15                  | 40      | 20                 | 10      | —                  | —       | 100                | 100     |
| 1200             | 63                 | 100     | 21                  | 60      | 71                 | 90      | 77                 | 90      | 100                | 100     |

The data in Table L-16 was used to construct property trend lines of Low Sigma (1% and 2%), High Sigma (10%), and Medium Sigma (Average of Low and High). Figure L-7 shows the trends.

#### L.11.5 DETERMINATION OF SIGMA PHASE EMBRITTELEMENT TECHNICAL MODULE SUBFACTOR

Figure L-8 outlines the process for determining the technical supplement subfactor.

Step 1. Determine the evaluation temperature. The material can be evaluated at normal operating conditions, or at a lower temperature such as shutdown or upset temperature.

Step 2. Determine the estimated % sigma in the material. This can be made through comparisons with materials in similar service, or via metallographic examination of a sample.

Step 3. Look up the subfactor on Table L-17.

Table L-17—Sigma Phase Embrittlement Technical Module Subfactors

| Evaluation Temperature | Low Sigma | Medium Sigma | High Sigma |
|------------------------|-----------|--------------|------------|
| 1200                   | 0.0       | 0.0          | 18         |
| 1000                   | 0.0       | 0.0          | 53         |
| 800                    | 0.0       | 0.2          | 160        |
| 600                    | 0.0       | 0.9          | 481        |
| 400                    | 0.0       | 1.3          | 1,333      |
| 200                    | 0.1       | 3            | 3,202      |
| 150                    | 0.3       | 5            | 3,871      |
| 100                    | 0.6       | 7            | 4,196      |
| 50                     | 0.9       | 11           | 4,196      |
| 0                      | 1.0       | 20           | 4,196      |
| -50                    | 1.1       | 34           | 4,196      |

#### References:

1. Viswanathan, R., *Damage Mechanisms and Life Assessment of High Temperature Components*, ASM International, 1989.
2. Timmins, P. F., *Predictive Corrosion and Failure Control in Process Operations*, ASM International, 1996.
3. Kaieda Y. and Oguchi A., "Brittle Fracture Stress of an Fe-Cr Alloy (Sigma Phase) under High Hydrostatic Pressure and High Temperature", *Trans. of the Japan Inst. of Metals*, Vol. 22, No. 2 (1981), pp. 83 to 95.
4. Ohta S., Saori M., and Yoshida T., "Analysis and Prevention of Failure in Steam Reforming Furnace Tube", *Kobe Steel Technical Bulletin 1059*, Kobe Steel Engineering Reports, Vol. 33, No. 2, April 1983.
5. Gaertner D. J., "Metallurgical Characterization of Sigma-tized Austenitic Stainless Steels in FCCU Regenerator Cyclone Systems", Paper #132, Corrosion '84, NACE, Houston TX.
6. Morris D., "The Influence of Sigma Phase on Creep Ductility in Type 316 Stainless Steel", *Scripta Metallurgica*, Vol. 13, pp. 1195-1196, 1979.
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8. Tikhonov A. S., and Osipov V. G., "Sigma Phase in Wrought Fe-Cr Alloys", Consultant's Bureau, New York, 1971.
9. Sorokina N. A., Ulyanin E. A., Fedorova V. I., Kaputkin II, and Belyaeva V. A., "Structure and Properties of Stainless Steel Alloyed with Molybdenum", Plenum Publishing, New York, 1975.
10. "High Temperature Corrosion in Refinery and Petrochemical Service", *High Temperature Engineering Bulletin HTB-2*, INCO, New York, 1960.
11. Peckner D., and Bernstein I. M., "Handbook of Stainless Steels," McGraw-Hill, New York 1977.

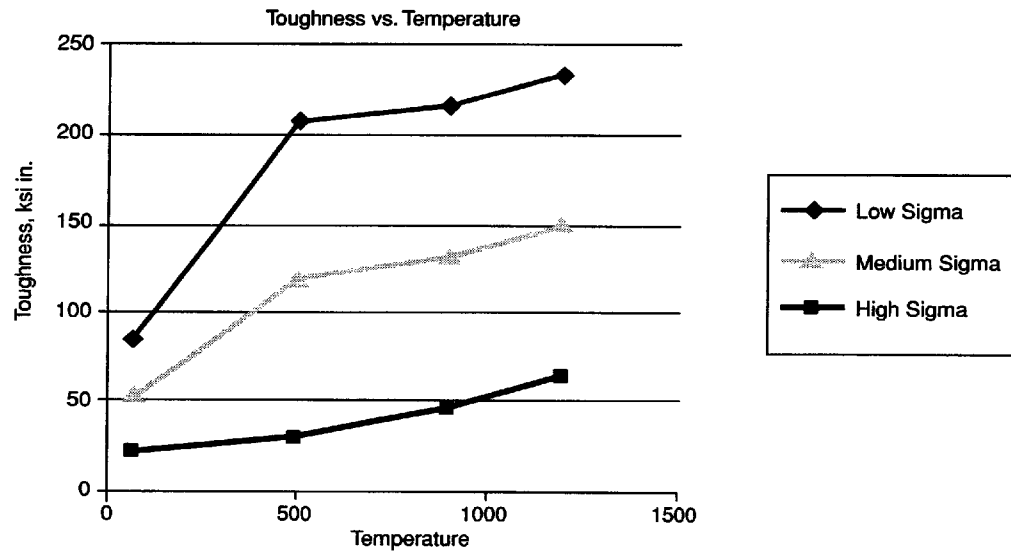


Figure L-7—Property Trends of Toughness vs. Temperature

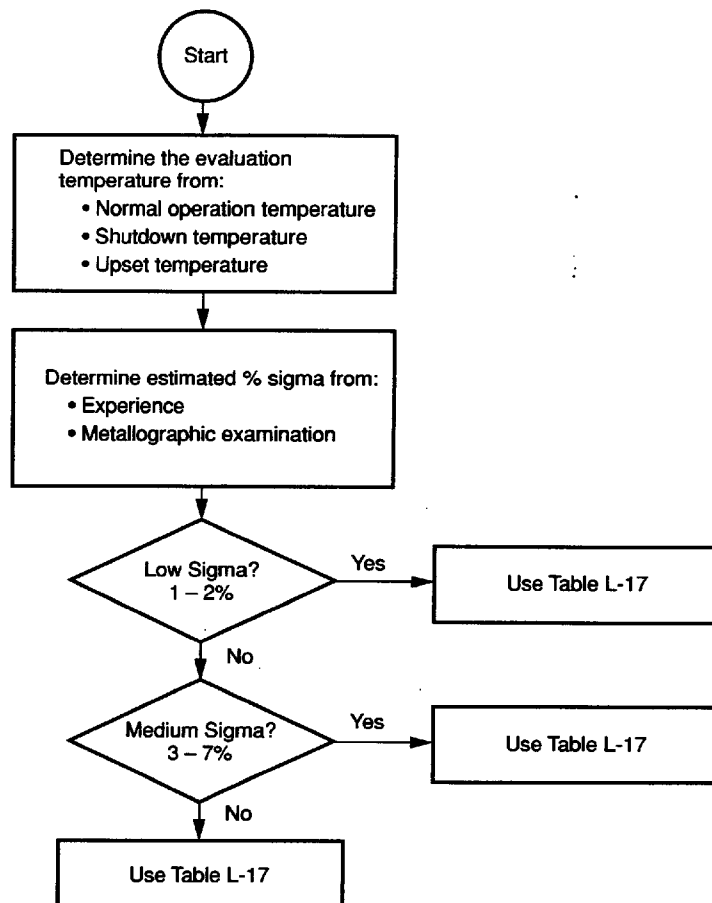


Figure L-8—Determination of Technical Module Subfactor for Sigma Phase Embrittlement

## APPENDIX M—EQUIPMENT LININGS TECHNICAL MODULE

### M.1 Scope

The purpose of this technical module is to provide a general RBI approach for handling equipment that has a protective internal lining. It is common practice to construct equipment with a material that is known to be subject to failure in the operating environment, but to protect the material from the environment with a lining that is resistant as described in Table M-1.

Table M-1—Typical Examples of Protective Internal Linings

| Lining Series ID | Environment (Damage Mechanisms of Base Metal) | Example Lining                                                                                                              |
|------------------|-----------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------|
| Alloy Linings    | Corrosive (Thinning, SCC)                     | Clad Alloy Weld<br>Overlay Alloy<br>Strip Lined Alloy                                                                       |
| Organic Coatings | Corrosive (Thinning, SCC)                     | Organic Coating or Lining                                                                                                   |
| Refractories     | High Temperature (Thinning, Creep, Erosion)   | Castable Refractory<br>Plastic Refractory<br>Refractory Brick<br>Ceramic Fiber Refractories<br>Refractory/Alloy Combination |
| Glass Lined      | Corrosive (Thinning, SCC)                     | Glass Lined                                                                                                                 |
| Acid Brick       | Corrosive (Thinning)                          | Brick / Mortar                                                                                                              |

A general approach to using RBI for lined equipment involves assessing the severity of damage that would be expected to occur on the base material, and then give credit for the existence of a lining. The degradation rate of the lining itself is not addressed. Evaluations of lining effectiveness at preventing damage are based on expert opinion.

### M.2 Technical Module Screening Questions

The screening question for the equipment linings general approach listed in Table M-2 is used to determine if the module should be entered.

Table M-2—Screening Questions for Equipment Linings General Approach

| Screening Questions         | Action                    |
|-----------------------------|---------------------------|
| 1. Is this equipment lined? | • If Yes, proceed to M.3. |

### M.3 Basic Data

The data listed in Table M-3 is required for the Equipment Linings Technical Module.

Table M-3—Basic Data Required for Analysis of Equipment Linings

| Basic Data                                                                 | Comments                           |
|----------------------------------------------------------------------------|------------------------------------|
| Type of Lining                                                             | Selected from list (See Table M-4) |
| Age of Lining, or Years Since Last Inspection (Thorough visual inspection) | User entered.                      |
| Lining Condition                                                           | User entered (see Table M-6)       |
| On-Line Monitoring for Lining Failure                                      | User Entered                       |
| TMSF for Base Material for all damage mechanisms                           | Use other Technical Modules        |

### M.4 Basic Assumptions

All linings afford some degree of protection from the operating environment. Many linings will last for an indefinite period of time, essentially being immune to damage mechanisms that might otherwise occur. Other linings will slowly degrade with time, and have a finite life. In such cases, the age of the lining (or the years since the last inspection) becomes important in assigning a factor. Particularly in the case of organic linings, the assumption is made that the lining is compatible with the environment, operated within design temperature limits (including steam out), and properly applied with appropriate curing.

### M.5 Determination of Technical Module Subfactor

**M.5.1** The technical module subfactor determination is described below and illustrated in the flow chart in Figure M-1. The basic approach is that the type of lining and the age or years since last inspection determines a lining failure factor. This is adjusted for a qualitative description of the lining condition. It is further adjusted based on the likelihood of equipment failure upon lining failure. (If the lining fails, does the equipment fail rapidly, or will it be expected to last for a considerable time?) A final credit is made for on-line monitoring that can provide early detection of a lining failure.

**M.5.2** The next step is to compare the adjusted lining failure factor with the total technical module subfactors as determined for the base metal. The minimum of the two values is used. The basis for this is that if the other technical module

M-1

Table M-4—Lining Types and Resistance

| Description                                                                                  | Resistance                                                                                                                 |
|----------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------|
| Alloy Cladding or Weld Overlay                                                               | Resistant to the environment.                                                                                              |
| Alloy Cladding or Weld Overlay                                                               | Possibly subject to attack, e.g. corrosion at welded joints, or diluted weld overlays.                                     |
| Strip Lined Alloy ("Wall papered")                                                           | Typically subject to failure at seams.                                                                                     |
| Organic Coating, typically > 30 mils dry film thickness.                                     | Limited life.                                                                                                              |
| Thermal Resistance Service:<br>Castable Refractory<br>Plastic Refractory<br>Refractory Brick | Subject to occasional spalling or collapse.                                                                                |
| Severe/abrasive service:<br>Castable Refractory<br>Ceramic Tile                              | Limited life in highly abrasive service.                                                                                   |
| Glass linings                                                                                | Complete protection, subject to failure due to thermal or mechanical shock.                                                |
| Acid Brick                                                                                   | Partial protection. The brick provides thermal protection, but is not intended to keep the fluid away from the base metal. |

subfactors are small compared to the lining failure factor, it does not yet matter if the lining has failed or not. This also provides a check that lining failure is not necessarily equated with equipment failure. It is also possible for the user to "switch off" the Equipment Linings Technical Module, and use the actual technical module values as determined for each damage mechanism.

**M.5.3** Tables M-5B and M-5A B provide the initial lining failure factors vs. age:

## M.6 Adjustment for Lining Condition

Table M-6 provides adjustment factors based on a qualitative assessment of the lining condition.

## M.7 Adjustment for On-Line Monitoring

Some lined equipment has monitoring to allow early detection of a leak or other failure of the lining. The monitoring allows orderly shutdown of the equipment before failure occurs. If on-line monitoring is used, and it is *known to be effective* at detecting lining deterioration, multiply the lining

failure factor by 0.1. Examples of monitoring systems include thermography or heat sensitive paint (refractory linings), weep holes with detection devices (loose alloy linings), electrical resistance detection (glass linings).

## M.8 Technical Module Subfactor

**M.8.1** Step 1: Determine the adjusted lining failure factor.

**M.8.2** Step 2: Determine the sum of the other technical module subfactors for the base material.

Note: For determination of thinning technical module subfactor, localized corrosion should be assumed when assigning inspection effectiveness. This is because coatings typically break down locally.

**M.8.3** Step 3: Use the lower of the two values from Steps 1 and 2 as the technical module subfactor.

Provision can be made to "switch off" the Equipment Linings Technical Module. This will allow the user additional flexibility in cases where lining failure does not reflect a failure of the equipment. (For example, the lining is installed for product purity purposes.)

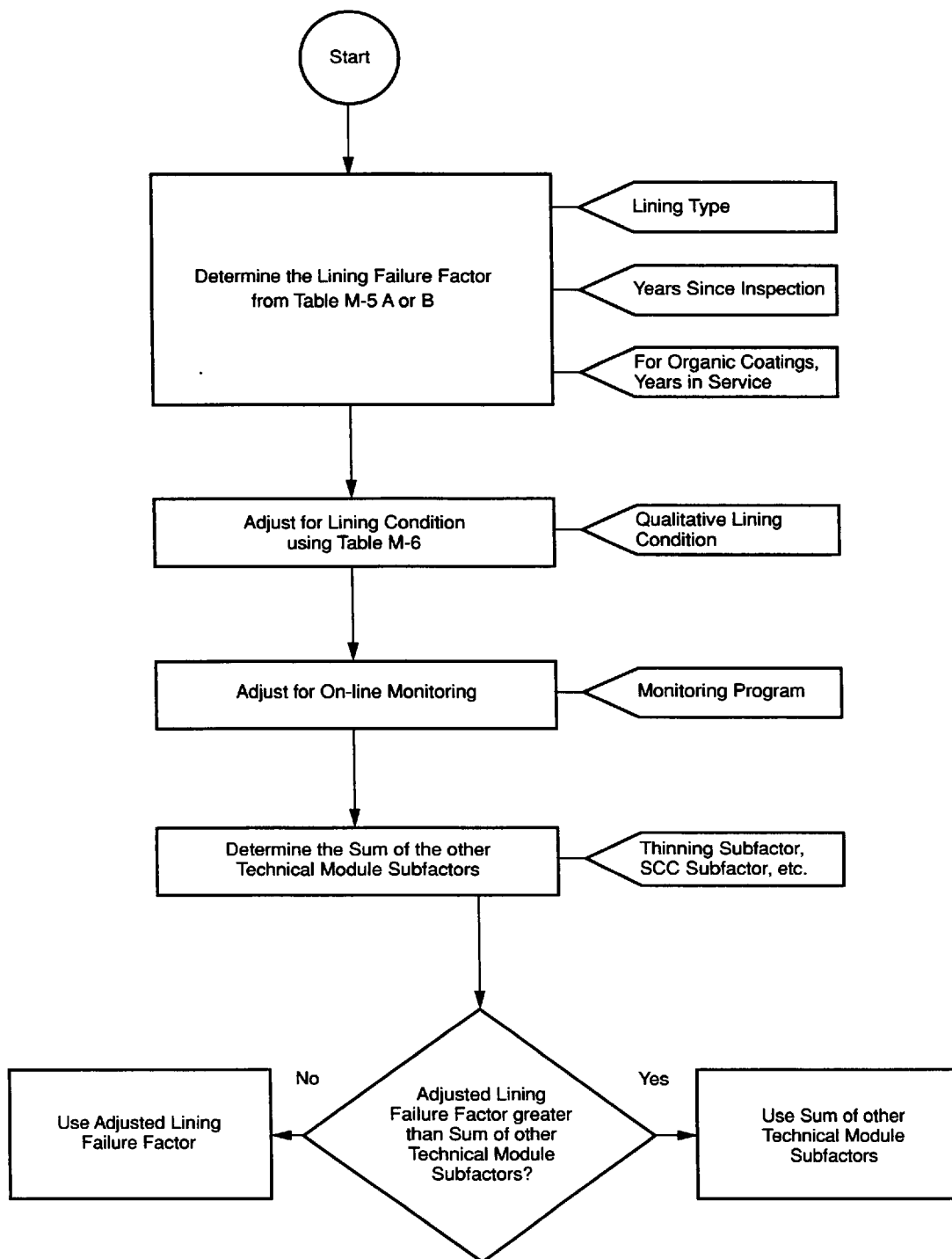


Figure M-1—Determination of the Equipment Linings Technical Module Subfactor

Table M-5A—Lining Failure Factors

| Years Since<br>Inspection<br>(Thorough<br>Visual) | Alloy Cladding<br>or Weld<br>Overlay—<br>(Resistant) | Alloy Cladding<br>or Weld<br>Overlay—<br>Possible Attack | Strip Lined<br>Alloy<br>(Resistant) | Castable<br>Refractory | Castable<br>Refractory—<br>Severe<br>Conditions | Glass<br>Lined | Acid<br>Brick |
|---------------------------------------------------|------------------------------------------------------|----------------------------------------------------------|-------------------------------------|------------------------|-------------------------------------------------|----------------|---------------|
| 1                                                 | 0                                                    | 3                                                        | 0.3                                 | 0.5                    | 9                                               | 3              | 0             |
| 2                                                 | 0                                                    | 4                                                        | 0.5                                 | 1                      | 40                                              | 4              | 0             |
| 3                                                 | 0                                                    | 6                                                        | 0.7                                 | 2                      | 146                                             | 6              | 0             |
| 4                                                 | 0                                                    | 7                                                        | 1                                   | 4                      | 428                                             | 7              | 0             |
| 5                                                 | 0                                                    | 9                                                        | 1                                   | 9                      | 1017                                            | 9              | 1             |
| 6                                                 | 0                                                    | 11                                                       | 2                                   | 16                     | 1978                                            | 11             | 1             |
| 7                                                 | 0.1                                                  | 13                                                       | 3                                   | 30                     | 3000                                            | 13             | 1             |
| 8                                                 | 0.1                                                  | 16                                                       | 4                                   | 53                     | 3000                                            | 16             | 1             |
| 9                                                 | 0.1                                                  | 20                                                       | 6                                   | 89                     | 3000                                            | 20             | 2             |
| 10                                                | 0.2                                                  | 25                                                       | 9                                   | 146                    | 3000                                            | 25             | 3             |
| 11                                                | 0.3                                                  | 30                                                       | 12                                  | 230                    | 3000                                            | 30             | 4             |
| 12                                                | 0.5                                                  | 36                                                       | 16                                  | 351                    | 3000                                            | 36             | 5             |
| 13                                                | 0.7                                                  | 44                                                       | 22                                  | 518                    | 3000                                            | 44             | 7             |
| 14                                                | 1                                                    | 53                                                       | 30                                  | 738                    | 3000                                            | 53             | 9             |
| 15                                                | 2                                                    | 63                                                       | 40                                  | 1017                   | 3000                                            | 63             | 11            |
| 16                                                | 2                                                    | 75                                                       | 53                                  | 1358                   | 3000                                            | 75             | 15            |
| 17                                                | 3                                                    | 89                                                       | 69                                  | 1758                   | 3000                                            | 89             | 19            |
| 18                                                | 4                                                    | 105                                                      | 89                                  | 2209                   | 3000                                            | 105            | 25            |
| 19                                                | 6                                                    | 124                                                      | 115                                 | 2697                   | 3000                                            | 124            | 31            |
| 20                                                | 9                                                    | 146                                                      | 146                                 | 3000                   | 3000                                            | 146            | 40            |
| 21                                                | 12                                                   | 170                                                      | 184                                 | 3000                   | 3000                                            | 170            | 50            |
| 22                                                | 16                                                   | 199                                                      | 230                                 | 3000                   | 3000                                            | 199            | 63            |
| 23                                                | 22                                                   | 230                                                      | 286                                 | 3000                   | 3000                                            | 230            | 78            |
| 24                                                | 30                                                   | 266                                                      | 351                                 | 3000                   | 3000                                            | 266            | 97            |
| 25                                                | 40                                                   | 306                                                      | 428                                 | 3000                   | 3000                                            | 306            | 119           |

Table M-5B—Lining Failure Factors—Organic Coatings

| Years in Service | Inspected more than 6 years ago | Inspected within last 6 years | Inspected within last 3 years |
|------------------|---------------------------------|-------------------------------|-------------------------------|
| 1                | 30                              | 1                             | 0                             |
| 2                | 89                              | 4                             | 0                             |
| 3                | 230                             | 16                            | 0                             |
| 4                | 518                             | 53                            | 0                             |
| 5                | 1017                            | 146                           | 0.2                           |
| 6                | 1758                            | 351                           | 1                             |
| 7                | 2697                            | 738                           | 4                             |
| 8                | 3000                            | 1358                          | 16                            |
| 9                | 3000                            | 2209                          | 53                            |
| 10               | 3000                            | 3000                          | 146                           |
| 11               | 3000                            | 3000                          | 351                           |
| 12               | 3000                            | 3000                          | 738                           |
| 13               | 3000                            | 3000                          | 1358                          |
| 14               | 3000                            | 3000                          | 2209                          |
| 15               | 3000                            | 3000                          | 3000                          |
| 16               | 3000                            | 3000                          | 3000                          |
| 17               | 3000                            | 3000                          | 3000                          |
| 18               | 3000                            | 3000                          | 3000                          |
| 19               | 3000                            | 3000                          | 3000                          |
| 20               | 3000                            | 3000                          | 3000                          |
| 21               | 3000                            | 3000                          | 3000                          |
| 22               | 3000                            | 3000                          | 3000                          |
| 23               | 3000                            | 3000                          | 3000                          |
| 24               | 3000                            | 3000                          | 3000                          |
| 25               | 3000                            | 3000                          | 3000                          |

Table M-6—Lining Condition Adjustment

| Qualitative Condition | Description                                                                                                                                                                                             | Adjustment Multiplier |
|-----------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------|
| Poor                  | The lining has either had previous failures or exhibits conditions that may lead to failure in the near future. Repairs to previous failures are not successful or are of poor quality.                 | Times 10              |
| Average               | The lining is not showing signs of excessive attack by any damage mechanisms. Local repairs may have been performed, but they are of good quality and have successfully corrected the lining condition. | Times 2               |
| Good                  | The lining is in "like new" condition with no signs of attack by any damage mechanisms. There has been no need for any repairs to the lining.                                                           | Times 1               |



## APPENDIX N—EXTERNAL DAMAGE TECHNICAL MODULE

### N.1 Scope

**N.1.1** External damage can occur on most process plant equipment. The result is a gradual thinning of some materials or may result in stress corrosion cracking of other materials. Perhaps the most serious cases of external damage involve corrosion under insulation (CUI). This form is especially hazardous because insulation can become wet or contaminated, accelerating the corrosion. Another reason that CUI is particularly serious is that it is very difficult to detect. In any case, the problem can be reduced or eliminated by proper inspection for corrosion, proper installation and maintenance of insulation, or by proper selection, application, and maintenance of protective coatings.

**N.1.2** External damage is evaluated separately for carbon/low alloy steels (subject to thinning) and austenitic stainless steels (subject to stress corrosion cracking). Each of these is dealt with in separate sections of this module.

**N.1.3** External damage for carbon and low alloy steels is a special case for application of the thinning technical module. External SCC for stainless steels is similar to the Cracking Technical Module. This is a separate Technical Module and the technical module subfactor is calculated and stored independently of other (internal) thinning and (internal) SCC mechanisms.

### N.2 Technical Module Screening Questions

The screening questions for external damage are listed in Table N-1. A flow chart of the screening process is shown in Figure N-1.

### N.3 External Corrosion of Carbon and Low Alloy Steels

As a general rule, plants located in areas with high annual rainfalls or warmer, marine locations are more prone to external corrosion than plants located in cooler, drier, mid-continent locations. Regardless of the climate, units located near cooling towers and steam vents are highly susceptible to external corrosion, as are units whose operating temperatures cycle through the dew point on a regular basis.

Mitigation of external corrosion is accomplished through proper painting. A regular program of inspection for paint deterioration and repainting will prevent most occurrences of external corrosion.

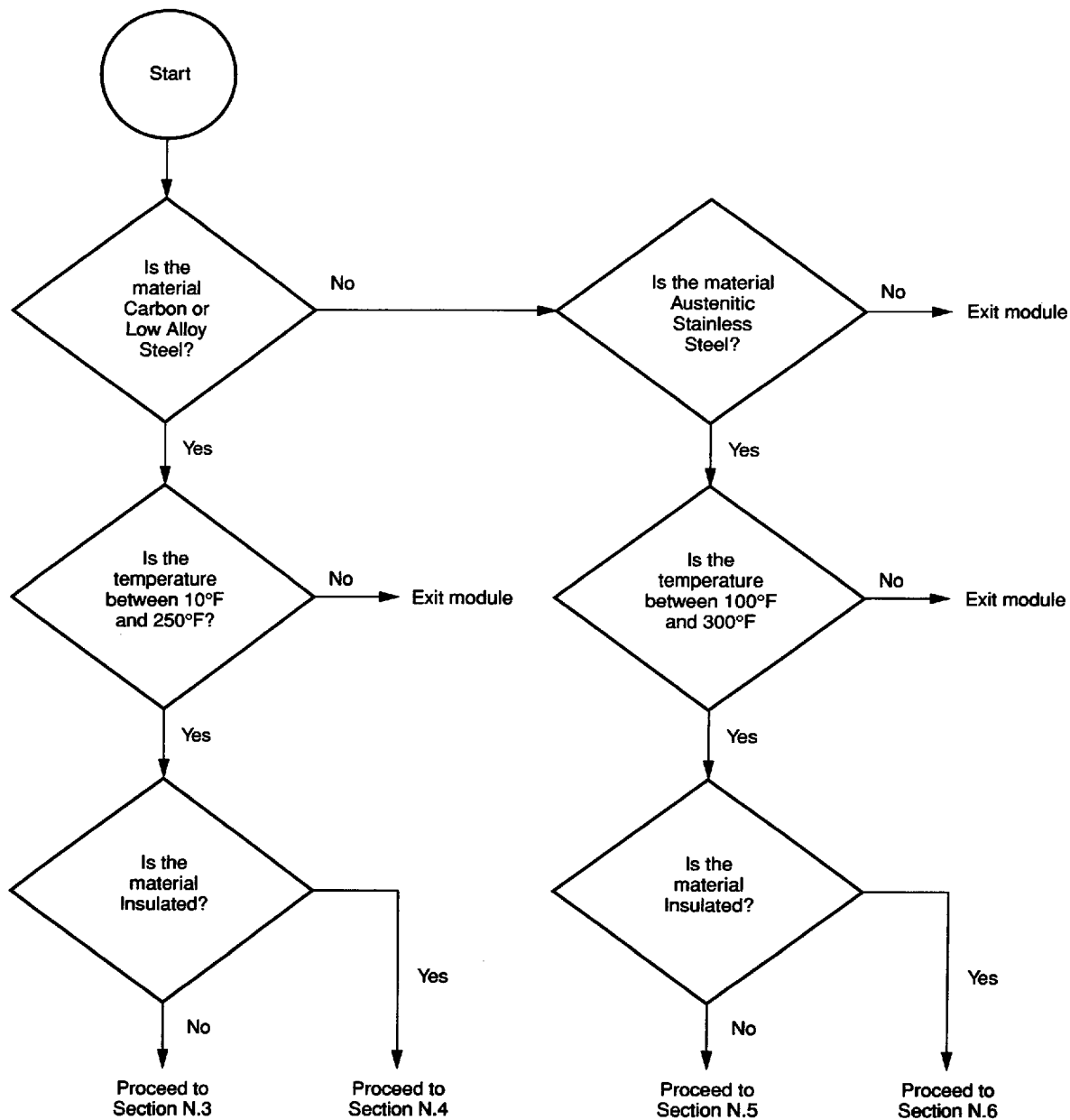
Certain areas and systems are more susceptible to external corrosion than others. Examples of highly suspect areas include, but are not limited to, the following:

The following are some examples of suspect areas that should be considered when performing inspection for external corrosion:

- a. Areas exposed to mist overspray from cooling towers,
- b. Areas exposed to steam vents,
- c. Areas exposed to deluge systems,
- d. Areas subject to process spills, ingress of moisture, or acid vapors,
- e. Carbon steel systems, operating between  $-10^{\circ}\text{F}$  and  $250^{\circ}\text{F}$ . External corrosion is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture,
- f. Carbon steel systems that normally operate in-service above  $25^{\circ}\text{F}$  but are in intermittent service or are subjected to frequent outages,

Table N-1—Screening Questions for External Corrosion

| Screening Questions                                                                                                           | Action                                                          |
|-------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------|
| 1. Is the material carbon or low alloy steel?                                                                                 | If Yes, Proceed to question 2.<br>If No, proceed to question 4. |
| 2. Is the operating temperature (either continuous or intermittent) between $10^{\circ}\text{F}$ and $250^{\circ}\text{F}$ ?  | If Yes, Proceed to question #3.<br>If No, exit module.          |
| 3. Is the equipment insulated?                                                                                                | If No, Proceed to N.3.<br>If Yes, Proceed to N.4.               |
| 4. Is the material austenitic stainless steel?                                                                                | If Yes, Proceed to question 5.<br>If No, exit module.           |
| 5. Is the operating temperature (either continuous or intermittent) between $100^{\circ}\text{F}$ and $300^{\circ}\text{F}$ ? | If Yes, Proceed to question #6.<br>If No, exit module.          |
| 6. Is the equipment insulated?                                                                                                | If No, Proceed to N.5.<br>If Yes, Proceed to N.6.               |



#### References

1. W. G. Ashbaugh, *Inspection of Vessels and Piping for Corrosion Under Insulation Corrosion: When, Where, and How To Do It*, Materials Performance, Volume 29, July 1990, pg. 38-42.
2. *Corrosion of Metals Under Thermal Insulation*, ASTM, Special Technical Publication 880.
3. *Piping Inspection Code*, 1st Edition, API 570, June 1993.
4. *A State-of-the-Art Report for Carbon Steel and Austenitic Stainless Steel Surfaces Under Thermal Insulation and Cementitious Fireproofing*, NACE Publication 6H189, Item No. 54268.

Figure N-1—Flowchart for External Damage

- g. Systems with deteriorated coating and/or wrappings,
- h. Cold service equipment consistently operating below the atmospheric dewpoint.

### N.3.1 BASIC DATA

The data listed in Table N-2 are required for external corrosion of carbon and low alloy steels.

### N.3.2 BASIC ASSUMPTIONS AND METHODS

See Tables N-3 through N-6.

### N.3.3 EXTERNAL CORROSION OF CARBON AND LOW ALLOY STEELS INSPECTION CATEGORIES

See Table N-7.

### N.3.4 DETERMINATION OF EXTERNAL CORROSION OF CARBON AND LOW ALLOY STEELS TECHNICAL MODULE SUBFACTOR

A flow chart for determining the technical module subfactor for external corrosion of carbon and low alloy steels is illustrated in Figure N-2.

Note: Due to the complexity of external corrosion and the variability of such corrosion it is suggested that a test case be calculated on some known cases of external corrosion to determine the best fit for all variables.

Step 1. Determine the driver for external corrosion in the plant or the portion of the plant under study.

Step 2. Determine the corrosion rate based on the driver and the operating temperature.

Step 3. Adjust the time period over which external corrosion may have occurred based on the type and date of the coating.

Step 4. Adjust the external corrosion rate based on the pipe support penalty (if applicable).

Step 5. Adjust the external corrosion rate based on the interface penalty (if applicable).

Step 6. Use the adjusted corrosion rate and number and type of inspections in the Thinning Module to determine the TMSF.

## N.4 CUI for Carbon and Low Alloy Steels

Corrosion under insulation (CUI) results from the collection of water in the vapor space (or annulus space) between the insulation and the metal surface. Sources of water may include rain, water leaks, condensation, cooling water tower drift, deluge systems, and steam tracing leaks. CUI causes wall loss in the form of localized corrosion. CUI generally occurs in the temperature range between 10°F and 250°F, with temperature range of 120°F to 200°F being the most severe environment.

Table N-2—Basic Data Required for External Corrosion of Carbon and Low Alloy Steels

| Variable                   | Comments                                                                                                                                                                                                  |
|----------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Driver                     | The drivers for external corrosion. This can be the weather at a location (e.g. marine), the potential for cooling tower drift, the use of sprinkler systems, or other contributors.                      |
| Rate, in mpy               | Corrosion rate for external corrosion. Based on temperature, and driver (see below), or user input. See Table N-3.                                                                                        |
| Date                       | Determines the time (in years) to be sent to the Thinning Technical Module. Defaults to date installed. Can change based on date of coating.                                                              |
| Inspection Effectiveness   | The effectiveness of the external corrosion inspection program. See Table N-7.                                                                                                                            |
| Inspection Number          | The number of external corrosion inspections                                                                                                                                                              |
| Coating Quality            | Relates to the type of coating applied. See Table N-4.<br>None, medium, or high<br>Suggestions:<br>None—No coating or primer only.<br>Medium—Single coat epoxy.<br>High—Multi-coat epoxy or filled epoxy. |
| Coating Date               | Determines the age of the coating.                                                                                                                                                                        |
| Pipe Support Penalty (Y/N) | If piping is supported directly on beams or other such configuration that does not allow for proper coating maintenance, external corrosion can be more severe. See Table N-5.                            |
| Interface Penalty (Y/N)    | If the piping has an interface where it enters either soil or water, this area is subject to increased corrosion. See Table N-6.                                                                          |

Table N-3—Corrosion Rate Default Matrix—Carbon Steel External Corrosion

| Operating Temperature,<br>°F | Marine / Cooling Tower Drift Area<br>(mpy) | Driver             |                     |
|------------------------------|--------------------------------------------|--------------------|---------------------|
|                              |                                            | Temperate<br>(mpy) | Arid / Dry<br>(mpy) |
| 10 or less                   | 0                                          | 0                  | 0                   |
| 11 to 60                     | 5                                          | 3                  | 1                   |
| 61 to 120                    | 2                                          | 1                  | 0                   |
| 121 to 200                   | 5                                          | 2                  | 1                   |
| 201 to 250                   | 1                                          | 0                  | 0                   |
| > 250                        | 0                                          | 0                  | 0                   |

Table N-4—Adjustments for Coatings Quality

| Coating Quality       |                         |                          |
|-----------------------|-------------------------|--------------------------|
| None                  | Medium                  | High                     |
| Date = Date Installed | Date = Coating Date + 5 | Date = Coating Date + 15 |

Table N-5—Adjustments for Pipe Support Penalty

| Penalty applies   | Penalty does not apply |
|-------------------|------------------------|
| Rate = Rate x 2.0 | Rate = Rate x 1.0      |

Table N-6—Adjustments for Interface Penalty

| Penalty applies   | Penalty does not apply |
|-------------------|------------------------|
| Rate = Rate x 2.0 | Rate = Rate x 1.0      |

Table N-7—Inspection Effectiveness

| Inspection Effectiveness Category | Inspection                                                                                                |
|-----------------------------------|-----------------------------------------------------------------------------------------------------------|
| A                                 | Visual inspection of > 95% of the exposed surface area with follow-up by UT, RT or pit gauge as required. |
| B                                 | Visual inspection of > 60% of the exposed surface area with follow-up by UT, RT or pit gauge as required. |
| C                                 | Visual inspection of > 30% of the exposed surface area with follow-up by UT, RT or pit gauge as required. |
| D                                 | Visual inspection of > 5% of the exposed surface area with follow-up by UT, RT or pit gauge as required.  |
| E                                 | Visual inspection of < 5% of the exposed surface area with follow-up by UT, RT or pit gauge as required.  |

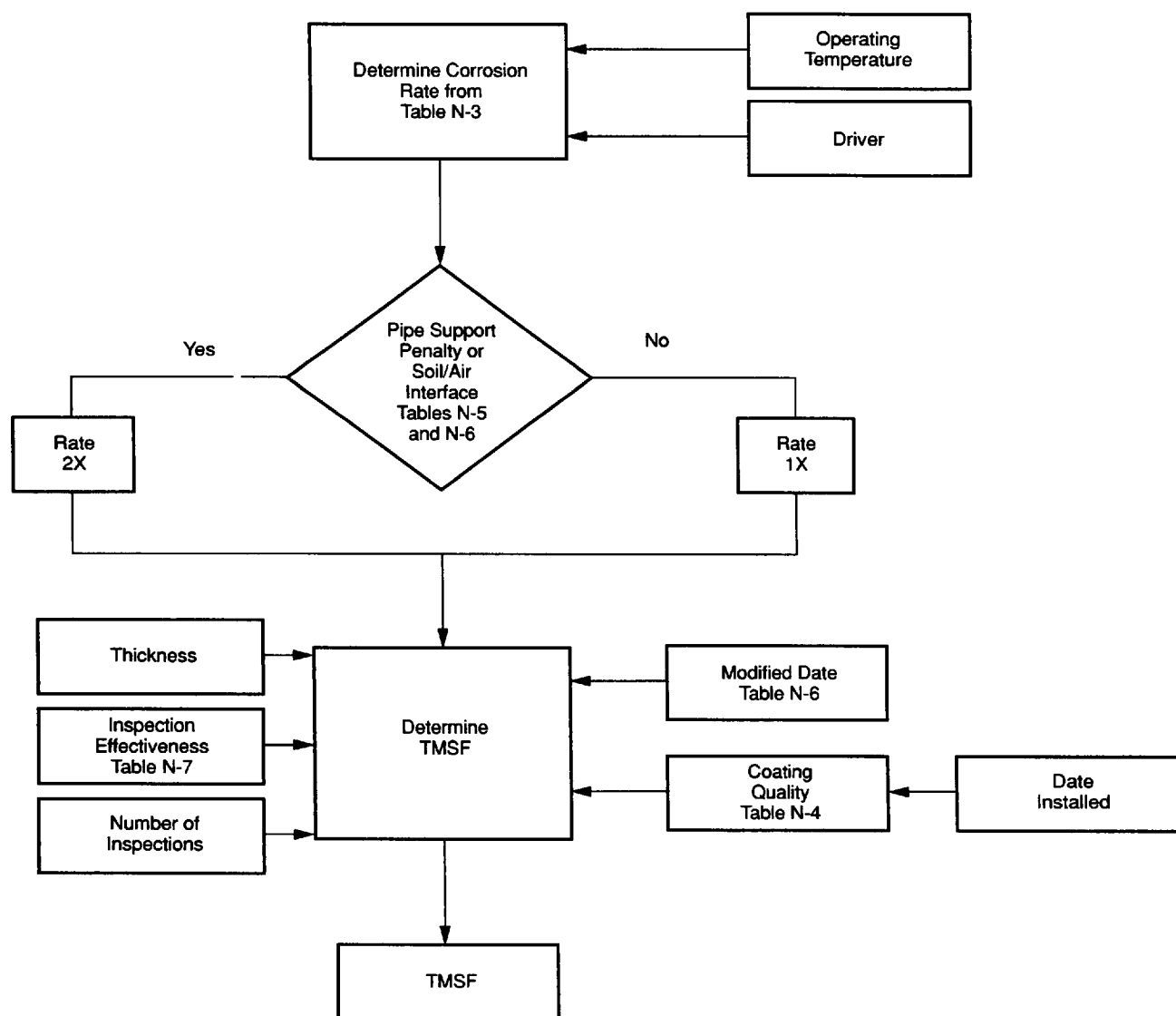


Figure N-2—Flowchart of External Corrosion for Carbon and Low Alloy Steels

As a general rule, plants located in areas with high annual rainfall or warmer, marine locations are more prone to CUI than plants located in cooler, drier, mid-continent locations. Regardless of the climate, units located near cooling towers and steam vents are highly susceptible to CUI, as are units whose operating temperatures cycle through the dew point on a regular basis. External inspection of insulated systems should include a review of the integrity of the insulation system for conditions that could lead to CUI and for signs of ongoing CUI, i.e. rust stains or bulging. However, external indicators of CUI are not always present.

Mitigation of CUI is accomplished through good insulation practices and proper coatings. Proper installation and

maintenance of insulation simply prevents an ingress of large quantities of water. In recent years, a coating system is frequently specified for equipment/piping operating in the CUI temperature range, and where CUI has been a problem. A high quality immersion grade coating, like those used in hot water tanks, is recommended. For guidance refer to NACE Publication 6H189. A good coating system should last a minimum of 15 years. If the equipment/piping is over 5 years old and does not have an acceptable protective coating, an inspection should be scheduled for the next opportunity.

Certain areas and systems are more susceptible to CUI than others. Specific locations and/or systems, such as penetra-

tions and visually damaged insulation areas, are highly suspect and should be considered during inspection program development. Examples of highly suspect areas include, but are not limited to, the following:

**a. Penetrations**

1. All penetrations or breaches in the insulation jacketing systems, such as deadlegs (vents, drains, and other similar items), hangers and other supports, valves and fittings, bolted-on pipe shoes, ladders, and platforms.
2. Steam tracer tubing penetrations.
3. Termination of insulation at flanges and other components.

**b. Damaged Insulation Areas**

1. Damaged or missing insulation jacketing
2. Termination of insulation in a vertical pipe or piece of equipment
3. Caulking that has hardened, has separated, or is missing
4. Bulges, staining of the jacketing system or missing bands (bulges may indicate corrosion product build-up)
5. Low points in systems that have a known breach in the insulation system, including low points in long unsupported piping runs
6. Carbon or low alloy steel flanges, bolting, and other components under insulation in high alloy piping

The following are some examples of other suspect areas that should be considered when performing inspection for CUI:

- a. Areas exposed to mist overspray from cooling towers.
- b. Areas exposed to steam vents.
- c. Areas exposed to deluge systems.
- d. Areas subject to process spills, ingress of moisture, or acid vapors.
- e. Carbon steel systems, including those insulated for personnel protection, operating between 10°F and 250°F. CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture.
- f. Carbon steel systems that normally operate in-service above 250°F but are in intermittent service or are subjected to frequent outages.
- g. Deadlegs and attachments that protrude from the insulation and operate at a different temperature than the operating temperature of the active line, i.e. insulation support rings, piping/platform attachments.
- h. Systems in which vibration has a tendency to inflict damage to insulation jacketing providing paths for water ingress.
- i. Steam traced systems experiencing tracing leaks, especially at tubing fittings beneath the insulation.
- j. Systems with deteriorated coating and/or wrappings.
- k. Cold service equipment consistently operating below the atmospheric dewpoint.

Inspection ports or plugs which are removed to permit thickness measurements on insulated systems represent a major contributor to possible leaks in insulated systems. Special attention should be paid to these locations. Promptly replacing and resealing of these plugs is imperative.

#### **N.4.1 BASIC DATA**

The data listed in Tables N-8 through N-15 are required for the CUI for carbon and low alloy steels.

#### **N.4.2 ASSUMPTIONS:**

1. Suspect areas include damaged insulation, penetrations, terminations, etc.
2. Inspection quality is high.
3. Surface preparation is sufficient to detect minimum wall for the NDE technique used to measure thickness.
4. Safety note: Exercise caution when preparing surfaces for inspection.

#### **N.4.3 DETERMINATION OF CUI FOR CARBON AND LOW ALLOY STEELS TECHNICAL MODULE SUBFACTOR**

A flow chart for determining the technical module subfactor for CUI for carbon and low alloy steels is illustrated in Figures N-3A and N-3B.

Note: Due to the complexity of external corrosion and the variability of such corrosion it is suggested that a test case be calculated on some known cases of external corrosion to determine the best fit for all variables.

Step 1. Determine the driver for external corrosion in the plant or the portion of the plant under study.

Step 2. Determine the corrosion rate based on the driver and the operating temperature.

Step 3. Adjust the time period over which external corrosion may have occurred based on the type and age of the coating.

Step 4. Adjust the external corrosion rate based on complexity of the system (number of branches, supports, etc. that may allow water to enter insulated coverings).

Step 5. Adjust the external corrosion rate based on a qualitative assessment of the condition of the insulation and weather barrier (if any).

Step 6. Adjust the external corrosion rate based on the pipe support penalty (if applicable).

Step 7. Adjust the external corrosion rate based on the interface penalty (if applicable).

Step 8. Use the adjusted corrosion rate and number and type of inspections in the Thinning Module to determine the TMSF.

Table N-8—Basic Data Required for CUI for Carbon and Low Alloy Steels

| Variable                   | Comments                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
|----------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Driver                     | The drivers for external corrosion under insulation. This can be the weather at a location (e.g. marine), the potential for cooling tower drift, the use of sprinkler systems, or other contributors.                                                                                                                                                                                                                                                                                                                                                                                   |
| Rate, in mpy               | Corrosion rate for external corrosion. Based on temperature, and driver (Table N-9), or user input.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| Date                       | Determines the time (in years) to be sent to the Thinning Technical Module. Defaults to date installed. Can change based on date of coating, time since last complete stripping and reinsulation.                                                                                                                                                                                                                                                                                                                                                                                       |
| Inspection Effectiveness   | The effectiveness of the CUI inspection program. See Table N-15.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| Inspection Number          | The number of CUI inspections.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
| Coating Quality            | Relates to the type of coating applied under the insulation: (Table N-10)<br>None, medium, or high<br>Suggestions:<br>None—No coating or primer only.<br>Medium—Single coat epoxy.<br>High—Multi coat epoxy or filled epoxy.                                                                                                                                                                                                                                                                                                                                                            |
| Coating Date               | Determines the age of the coating.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
| Complexity                 | The number of branches (Table N-11), etc.: Below Average, Average, Above Average                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| Good Insulation Condition? | Determine whether the insulation condition is good based on external visual inspection of jacketing condition. Good insulation will show no signs of damage (i.e. punctured, torn or missing water proofing, and missing caulking) or standing water (i.e. brown, green, or black stains). Take careful note of areas where water can enter into the insulation system, such as inspection ports and areas where the insulation is penetrated (i.e. nozzles, ring supports and clips). Horizontal areas also accumulate water. If any damage is noted, default to "No." See Table N-12. |
| Pipe Support Penalty (Y/N) | If piping is supported directly on beams or other such configuration that does not allow for proper coating maintenance, external corrosion can be more severe. See Table N-13.                                                                                                                                                                                                                                                                                                                                                                                                         |
| Interface Penalty (Y/N)    | If the piping has an interface where it enters either soil or water, this area is subject to increased corrosion. See Table N-14.                                                                                                                                                                                                                                                                                                                                                                                                                                                       |

Table N-9—Basic Assumptions and Methods for CUI for Carbon and Low Alloy Steels

| Operating Temperature,<br>°F | Driver                                     |                    |                     |
|------------------------------|--------------------------------------------|--------------------|---------------------|
|                              | Marine / Cooling Tower Drift Area<br>(mpy) | Temperate<br>(mpy) | Arid / Dry<br>(mpy) |
| 10 or less                   | 0                                          | 0                  | 0                   |
| 11 to 60                     | 5                                          | 3                  | 1                   |
| 61 to 120                    | 2                                          | 1                  | 0                   |
| 121 to 200                   | 10                                         | 5                  | 2                   |
| 201 to 250                   | 2                                          | 1                  | 0                   |
| > 250                        | 0                                          | 0                  | 0                   |

Table N-10—Adjustments for Coatings

| Coating Quality       |                         |                          |
|-----------------------|-------------------------|--------------------------|
| None                  | Medium                  | High                     |
| Date = Date Installed | Date = Coating Date + 5 | Date = Coating Date + 15 |

Table N-11—Adjustments for Complexity

| Below Average             | Average                  | Above Average             |
|---------------------------|--------------------------|---------------------------|
| Rate = Rate $\times$ 0.75 | Rate = Rate $\times$ 1.0 | Rate = Rate $\times$ 1.25 |

Table N-12—Adjustments for Insulation Condition

| Below Average            | Average                  | Above Average             |
|--------------------------|--------------------------|---------------------------|
| Rate = Rate $\times$ 1.0 | Rate = Rate $\times$ 0.5 | Rate = Rate $\times$ 0.25 |

Table N-13—Adjustments for Pipe Support Penalty

| Penalty applies          | Penalty does not apply   |
|--------------------------|--------------------------|
| Rate = Rate $\times$ 2.0 | Rate = Rate $\times$ 1.0 |

Table N-14—Adjustments for Interface Penalty

| Penalty applies          | Penalty does not apply   |
|--------------------------|--------------------------|
| Rate = Rate $\times$ 2.0 | Rate = Rate $\times$ 1.0 |

## N.5 External SCC of Austenitic Stainless Steels

Mitigation of external Cl-SCC is best accomplished by preventing chloride accumulation on the stainless steel surface. On uninsulated surfaces, Cl containing fluids, mists, or solids should be prevented from contacting the surface. Markers, dyes, tape, etc. used on stainless steels should be certified suitable for such application. In rare cases, uninsulated stainless steels could be protected externally by a coating.

### N.5.1 BASIC DATA

The data listed in Table N-16 are required for the external SCC of Austenitic Steels Technical Module.

### N.5.2 BASIC ASSUMPTIONS AND METHODS

See Tables N-17 through N-19.

### N.5.3 DETERMINATION OF TECHNICAL MODULE SUBFACTOR

See Figure N-4 for a flow chart on determining the technical module subfactor for external Cl-SCC of austenitic stainless steels.

Note: Due to the complexity of external corrosion and the variability of such corrosion it is suggested that a test case be calculated on some known cases of external corrosion to determine the best fit for all variables.

Step 1. Determine the driver for external corrosion in the plant or the portion of the plant under study.

Step 2. Determine the susceptibility based on the driver and the operating temperature.

Step 3. Adjustment for existing cracking: If SCC has been detected in this equipment, then the susceptibility is considered high.

Step 4. The severity index for Cl-SCC is outlined in Table N-20.

Step 5. Determine the time period over which external corrosion may have occurred based on the time since last inspection (if inspected), or type and age of the coating.

Step 6. It is assumed that the likelihood for cracking would increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. Therefore, the TMSF should be increased by the following relationship:

Step 7. Final TMSF = TMSF  $\times$  (years since last inspection for cracking)<sup>1.1</sup>.

Step 8. As an example, a piece of equipment/piping with a TMSF of 10 would increase to a Final TMSF of 58 in five years without any inspection and would increase further to 125 after ten years without inspection.



Table N-15—CUI for Carbon and Low Alloy Steels Inspection Categories

| Inspection Effectiveness Category | Insulation Removed                                                                                                                                                                                                                                                                                                                                                                                                                                                             | Insulation Not Removed                                                                                                                                                                                                                                                                                                 |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| A                                 | <ul style="list-style-type: none"> <li>Remove &gt;95% of the insulation;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>visual inspection of the exposed surface area with follow-up by UT, RT or pit gauge as required.</li> </ul>                                                                                                                                                                                                                       | <p>For the total surface area:</p> <ul style="list-style-type: none"> <li>&gt; 95% profile or real-time radiography.</li> </ul>                                                                                                                                                                                        |
| B                                 | <p>For the total surface area:</p> <ul style="list-style-type: none"> <li>&gt;95% external visual inspection prior to removal of insulation;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>remove &gt;60% of total surface area of insulation including suspect areas;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>visual inspection of the exposed surface area with follow-up by UT, RT or pit gauge as required.</li> </ul>   | <p>For the total surface area:</p> <ul style="list-style-type: none"> <li>&gt; 95% external visual inspection;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>follow-up with profile or real time radiography of &gt; 60% of total surface area of insulation including suspect areas.</li> </ul> |
| C                                 | <p>For the total surface area:</p> <ul style="list-style-type: none"> <li>&gt; 95% external visual inspection prior to removal of insulation;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>remove &gt; 30% of total surface area of insulation including suspect areas;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>visual inspection of the exposed surface area with follow-up by UT, RT or pit gauge as required.</li> </ul> | <p>For the total surface area:</p> <ul style="list-style-type: none"> <li>&gt;95% external visual inspection;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>follow-up with profile or real time radiography of &gt; 30% of total surface area of insulation including suspect areas.</li> </ul>  |
| D                                 | <ul style="list-style-type: none"> <li>&gt; 95% external visual inspection prior to removal of insulation;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>remove &gt; 5% of total surface area of insulation including suspect areas.</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>visual inspection of the exposed surface area with follow-up by UT, RT or pit gauge as required.</li> </ul>                                     | <p>For the total surface area:</p> <ul style="list-style-type: none"> <li>&gt;95% external visual inspection;</li> </ul> <p><b>AND</b></p> <ul style="list-style-type: none"> <li>follow-up with profile or real time radiography of &gt;5% of total surface area of insulation including suspect areas.</li> </ul>    |
| E                                 | <ul style="list-style-type: none"> <li>&lt; 5% insulation removal and inspection;</li> </ul> <p><b>OR</b></p> <ul style="list-style-type: none"> <li>no inspection or ineffective inspection technique.</li> </ul>                                                                                                                                                                                                                                                             | <p>No inspection or ineffective inspection technique or &lt; 95% visual inspection.</p>                                                                                                                                                                                                                                |

Table N-16—Basic Data Required for External SCC of Austenitic Stainless Steels

| Variable                 | Comments                                                                                                                                                                             |
|--------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Driver                   | The drivers for external corrosion. This can be the weather at a location (e.g. marine), the potential for cooling tower drift, the use of sprinkler systems, or other contributors. |
| Crack Severity           | Crack severity for external corrosion cracking module.<br>Based on susceptibility (temperature, and weather, see Table N-17).                                                        |
| Date                     | Determines the time (years) to be used for calculation of the TMSF.<br>Defaults to date installed. Can change based on date of coating, date of last inspection.                     |
| Inspection Effectiveness | The effectiveness of the external corrosion inspection program. See Table N-19.                                                                                                      |
| Inspection Number        | The number of external corrosion inspections.                                                                                                                                        |
| Inspection Date          | The date of the last external corrosion inspections.                                                                                                                                 |
| Coating Quality          | Relates to the type of coating applied under the insulation.<br>None, medium, or high. See Table N-18.                                                                               |
| Coating Date             | Determines the age of the coating.<br>Must be supplied unless coating quality is none.                                                                                               |

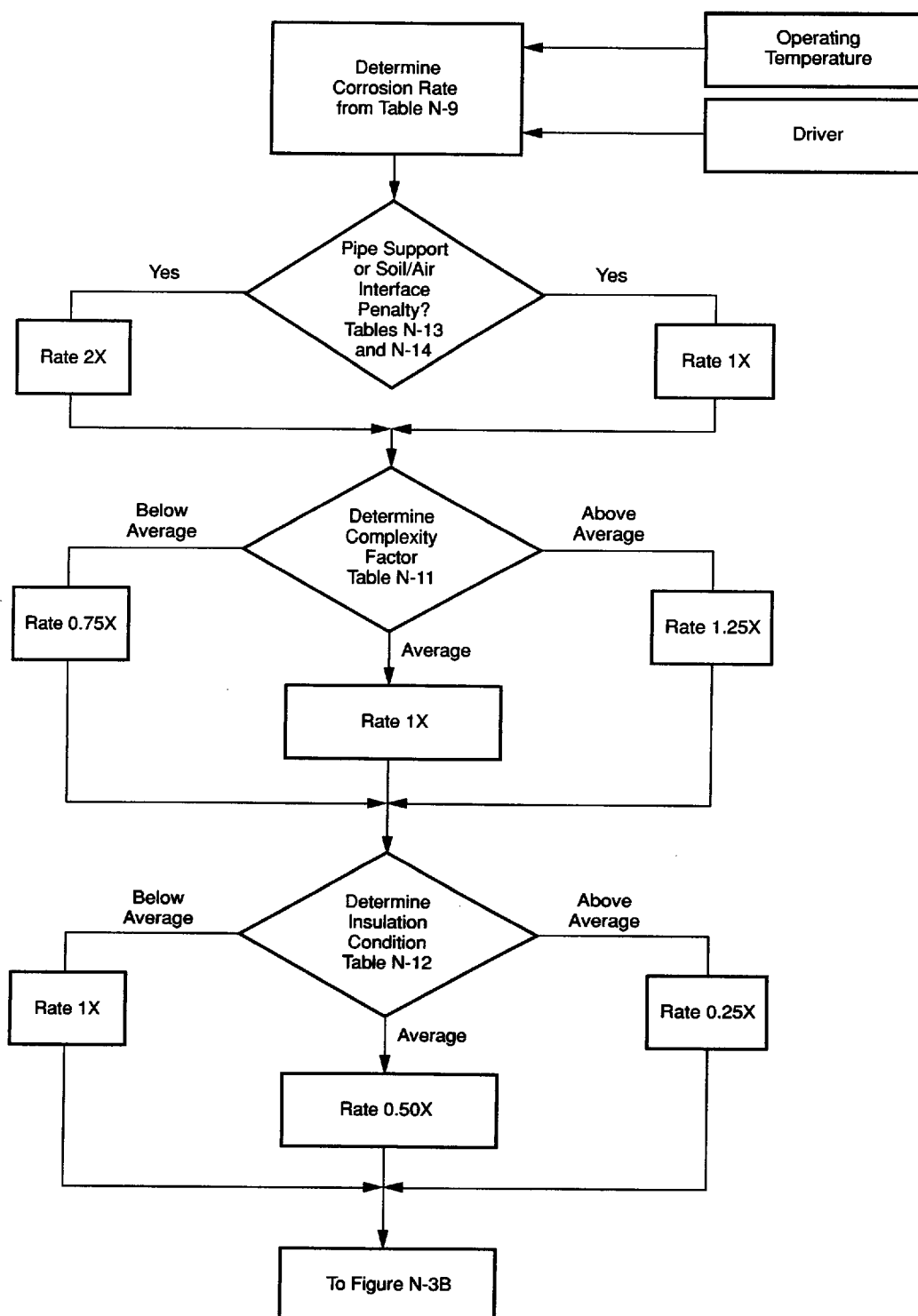


Figure N-3A—Flowchart of CUI for Carbon and Low Alloy Steels

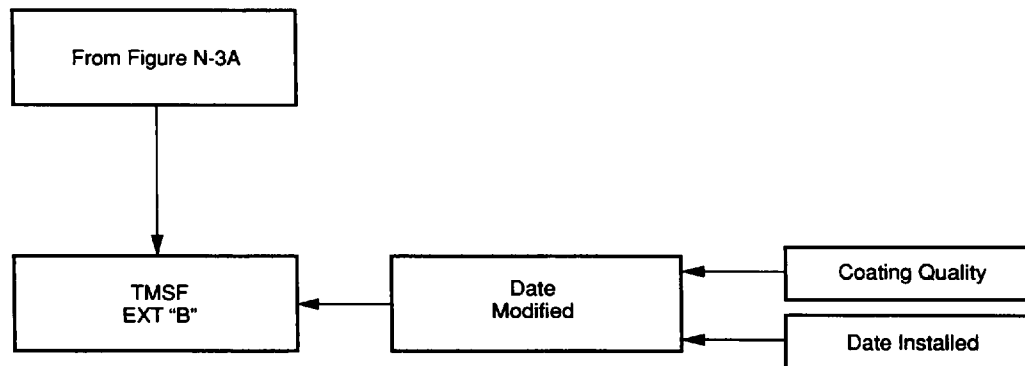


Figure N-3B—Flowchart of CUI for Carbon and Low Alloy Steels

Table N-17—SCC Susceptibility of Austenitic Stainless Steels

| Operating Temperature,<br>°F | Driver                               |           |      |
|------------------------------|--------------------------------------|-----------|------|
|                              | Marine / Cooling<br>Tower Drift Area | Temperate | Arid |
| < 140                        | None                                 | None      | None |
| 140 to 200                   | Medium                               | Low       | None |
| 200 to 300                   | Low                                  | Low       | None |
| > 300                        | None                                 | None      | None |

Table N-18—Adjustments for Coatings

| Coating Quality                                                                               |                                                                                           |                                                                                            |
|-----------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------|
| None                                                                                          | Medium                                                                                    | High                                                                                       |
| Date = Date installed or date of since last inspection (if the equipment has been inspected). | Date = Coating Date + 5 or date of last inspection (if the equipment has been inspected). | Date = Coating Date + 15 or date of last inspection (if the equipment has been inspected). |

Table N-19—External SCC of Austenitic Stainless Steel Inspection Categories

| Inspection Effectiveness<br>Category | Intrusive Inspection                                                                                                                                                       |
|--------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| A                                    | For the total surface area: <ul style="list-style-type: none"> <li>&gt;95% dye penetrant or eddy current test with UT follow-up of relevant indications.</li> </ul>        |
| B                                    | For the total surface area: <ul style="list-style-type: none"> <li>&gt;60% dye penetrant or eddy current testing with UT follow-up of all relevant indications.</li> </ul> |
| C                                    | For the total surface area: <ul style="list-style-type: none"> <li>&gt;30% dye penetrant or eddy current testing with UT follow-up of all relevant indications.</li> </ul> |
| D                                    | For the total surface area: <ul style="list-style-type: none"> <li>&gt;5% dye penetrant or eddy current testing with UT follow-up of all relevant indications.</li> </ul>  |
| E                                    | Less than "D" effectiveness or no inspection or ineffective inspection technique used.                                                                                     |

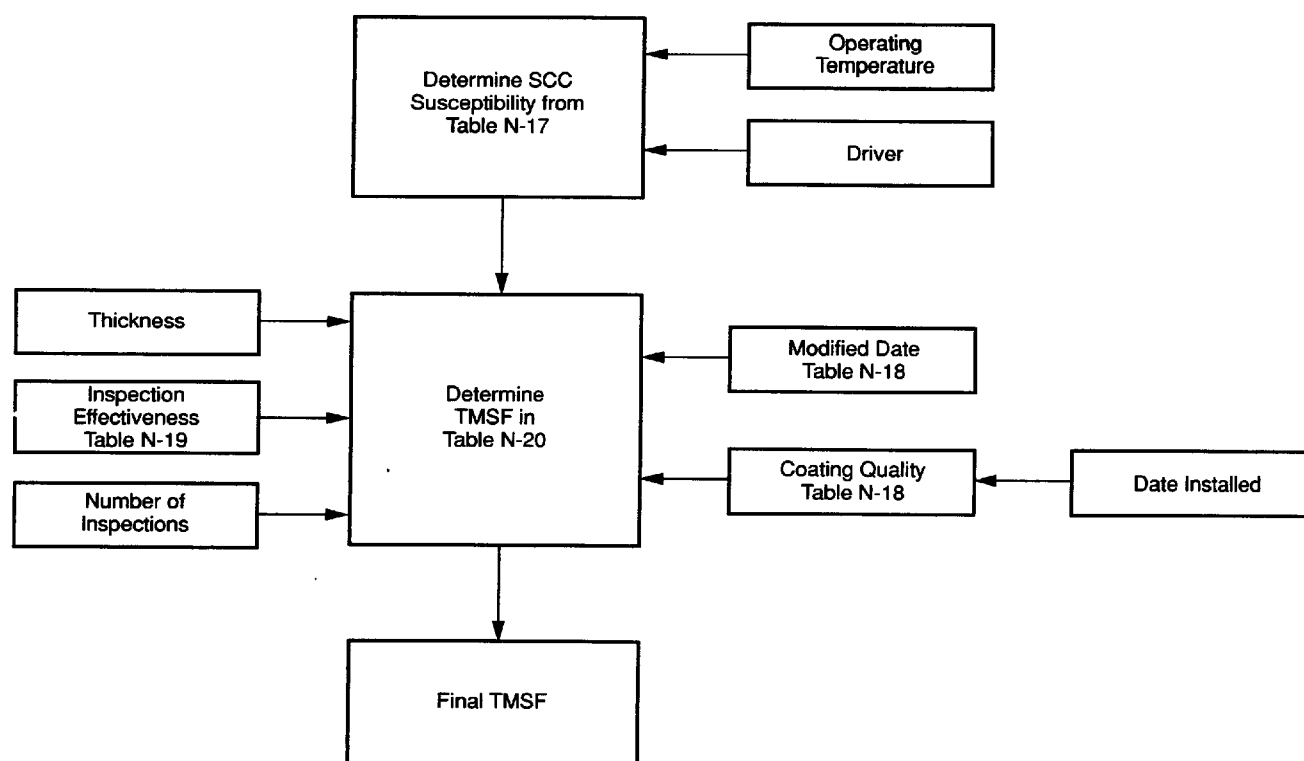


Figure N-4—Flowchart of External SCC for Austenitic Stainless Steels

Table N-20—Severity Index for Cl-SCC

| Susceptibility | External corrosion for stainless steels (Cl-SCC) |
|----------------|--------------------------------------------------|
| High           | 50                                               |
| Medium         | 10                                               |
| Low            | 1                                                |

## N.6 External CUI SCC for Austenitic Stainless Steels

Insulation can be a source of chlorides and/or cause the retention of water and chloride concentrating under the insulation. Cl-SCC can be caused by the spray from sea water and cooling water towers carried by the prevailing winds. The spray soaks the insulation over the austenitic stainless steel equipment/piping, the chloride concentrates by evaporation, and cracking occurs in the areas with residual stresses (e.g. weld and bends). Other cases of cracking under insulation have resulted from water dripping on insulated pipe and leaching chlorides from insulation.

Mitigation of Cl-SCC under insulation is best accomplished by preventing chloride accumulation on the stain-

less steel surface. This is best accomplished by first maintaining the integrity of the insulation. Second, by preventing chloride ions from contacting the stainless steel surface with a protective coating. An immersion grade coating suitable for stainless steel is the most practical and proven method of protection. However, wrapping of the stainless steel with aluminum foil which serves as both a barrier coating and a cathodic protection anode has also proven to be effective.

### N.6.1 BASIC DATA

The data listed in Table N-21 are required for the external CUI SCC for austenitic stainless steels in technical module.

### N.6.2 BASIC ASSUMPTIONS AND METHODS

See Tables N-22 through N-27.

### N.6.3 DETERMINATION OF TECHNICAL MODULE SUBFACTOR

A flow chart for determining the technical module subfactor for external CUI SCC for austenitic stainless steels is illustrated in Figures N-5A and N-5B.

Table N-21—Basic Data Required for External CUI SCC for Austenitic Stainless Steels

| Variable                                          | Comments                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
|---------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Driver                                            | The drivers for external corrosion.<br>This can be the weather at a location (e.g. marine), the potential for cooling tower drift, the use of sprinkler systems, or other contributors.                                                                                                                                                                                                                                                                         |
| Crack Severity                                    | Crack severity for external corrosion cracking module.<br>Based on susceptibility (temperature, and weather, see Table N-22).                                                                                                                                                                                                                                                                                                                                   |
| Date                                              | Determines the time (years) to be used for calculation of the TMSF.<br>Defaults to date installed. Can change based on date of coating, date of last inspection.                                                                                                                                                                                                                                                                                                |
| Inspection Effectiveness                          | The effectiveness of the external corrosion inspection program.                                                                                                                                                                                                                                                                                                                                                                                                 |
| Inspection Number                                 | The number of external corrosion inspections.                                                                                                                                                                                                                                                                                                                                                                                                                   |
| Inspection Date                                   | The date of the last external corrosion under insulation inspections.                                                                                                                                                                                                                                                                                                                                                                                           |
| Coating Quality                                   | Relates to the type of coating applied under the insulation:<br>None, medium, or high. See Table N-23.                                                                                                                                                                                                                                                                                                                                                          |
| Coating Age                                       | The age of the coating.<br>Must be supplied unless coating quality is none.                                                                                                                                                                                                                                                                                                                                                                                     |
| Is the Condition of Insulation System Good? (Y/N) | Good insulation will show "No Signs" of damage (i.e. punctured, torn or missing water proofing, and missing caulking) or standing water (i.e. brown, green or black stains). Take careful note of areas where water can enter into the insulation system, such as inspection ports and areas where the insulation is penetrated (i.e. nozzles, ring supports and clips). Horizontal areas also accumulate water. Any damage noted—default "No". See Table N-25. |
| Complexity                                        | The number of branches, etc.: Below Average, Average, Above Average. See Table N-24.                                                                                                                                                                                                                                                                                                                                                                            |
| Is insulation CI "Free"? (Y/N)                    | Determine if the insulation is CI free. If unknown assume CI is present. See Table N-26.                                                                                                                                                                                                                                                                                                                                                                        |

Table N-22—For SCC Susceptibility of Austenitic Stainless Steels

| Operating Temperature,<br>°F | Driver                            |           |      |
|------------------------------|-----------------------------------|-----------|------|
|                              | Marine / Cooling Tower Drift Area | Temperate | Arid |
| < 140                        | None                              | None      | None |
| 140 to 200                   | High                              | Medium    | Low  |
| 200 to 300                   | Medium                            | Low       | None |
| > 300                        | None                              | None      | None |

Table N-23—Adjustments for Coatings

| Coating Quality                                                                               |                                                                                           |                                                                                            |
|-----------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------|
| None                                                                                          | Medium                                                                                    | High                                                                                       |
| Date = Date installed or date of since last inspection (if the equipment has been inspected). | Date = Coating Date + 5 or date of last inspection (if the equipment has been inspected). | Date = Coating Date + 15 or date of last inspection (if the equipment has been inspected). |

Table N-24—Adjustments for Complexity

| Below Average                                             | Average                      | Above Average                                              |
|-----------------------------------------------------------|------------------------------|------------------------------------------------------------|
| Decrease Susceptibility one level<br>(e.g. Medium to Low) | No change to Susceptibility. | Increase Susceptibility one level<br>(e.g. Medium to High) |

Table N-25—Adjustments for Insulation Condition

| Below Average                                             | Average                      | Above Average                                              |
|-----------------------------------------------------------|------------------------------|------------------------------------------------------------|
| Increase Susceptibility one level<br>(e.g. Low to Medium) | No change to Susceptibility. | Decrease Susceptibility one level<br>(e.g. High to Medium) |

Table N-26—Adjustments for Chloride Free Insulation

| Chloride Free                                          | Contains Chlorides           |
|--------------------------------------------------------|------------------------------|
| Decrease Susceptibility one level (e.g. Medium to Low) | No change to Susceptibility. |

Table N-27—CUI for Stainless Steels Inspection Categories

| Inspection Effectiveness Category | Intrusive Inspection                                                                                                        | Non-intrusive Inspection                                                                                                                          |
|-----------------------------------|-----------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------|
| A                                 | For the total surface area:<br>• > 95% dye penetrant or eddy current test with UT follow-up of relevant indications.        | No inspection techniques yet available meet requirements of "A".                                                                                  |
| B                                 | For the total surface area:<br>• > 60% dye penetrant or eddy current testing with UT follow-up of all relevant indications. | For the total surface area:<br>• > 95% automated or manual ultrasonic scanning<br>OR<br>• AE testing with 100% follow-up of relevant indications. |
| C                                 | For the total surface area:<br>• > 30% dye penetrant or eddy current testing with UT follow-up of all relevant indications. | For the total surface area:<br>• > 67% automated or manual ultrasonic scanning                                                                    |
| D                                 | For the total surface area:<br>• > 5% dye penetrant or eddy current testing with UT follow-up of all relevant indications   | For the total surface area:<br>• > 30% automated or manual ultrasonic scanning<br>OR<br>• > 60% radiographic testing.                             |
| E                                 | Less than "D" effectiveness or no inspection or ineffective inspection technique used                                       | Less than "D" effectiveness or no inspection or ineffective inspection technique used                                                             |

Note: Due to the complexity of external corrosion and the variability of such corrosion it is suggested that a test case be calculated on some known cases of external corrosion to determine the best fit for all variables.

1. Determine the driver for external corrosion in the plant or the portion of the plant under study.
2. Determine the susceptibility based on the driver and the operating temperature.
3. Adjustment for existing cracking: If SCC has been detected in this equipment, then the susceptibility is considered high.
4. The severity index for Cl-SCC is outlined in Table N-20.

Step 5. Determine the time period over which external corrosion may have occurred based on the time since last inspection (if inspected), or type and age of the coating.

Step 6. Adjust the susceptibility based on complexity of the system (number of branches, supports, etc. that may allow water to enter insulated coverings.

Step 7. Adjust the susceptibility based on a qualitative assessment of the condition of the insulation and weather barrier (if any).

Step 8. Use the adjusted susceptibility and number and type of inspections in the SCC Module (see Table M-10) to determine the TMSF.

Step 9. It is assumed that the likelihood for cracking would increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. Therefore, the TMSF should be increased by the following relationship:

Step 10. Final TMSF = TMSF × (years since last inspection for cracking)<sup>1.1</sup>.

Step 11. As an example, a piece of equipment/piping with a TMSF of 10 would increase to a Final TMSF of 58 in five years without any inspection and would increase further to 125 after ten years without inspection.

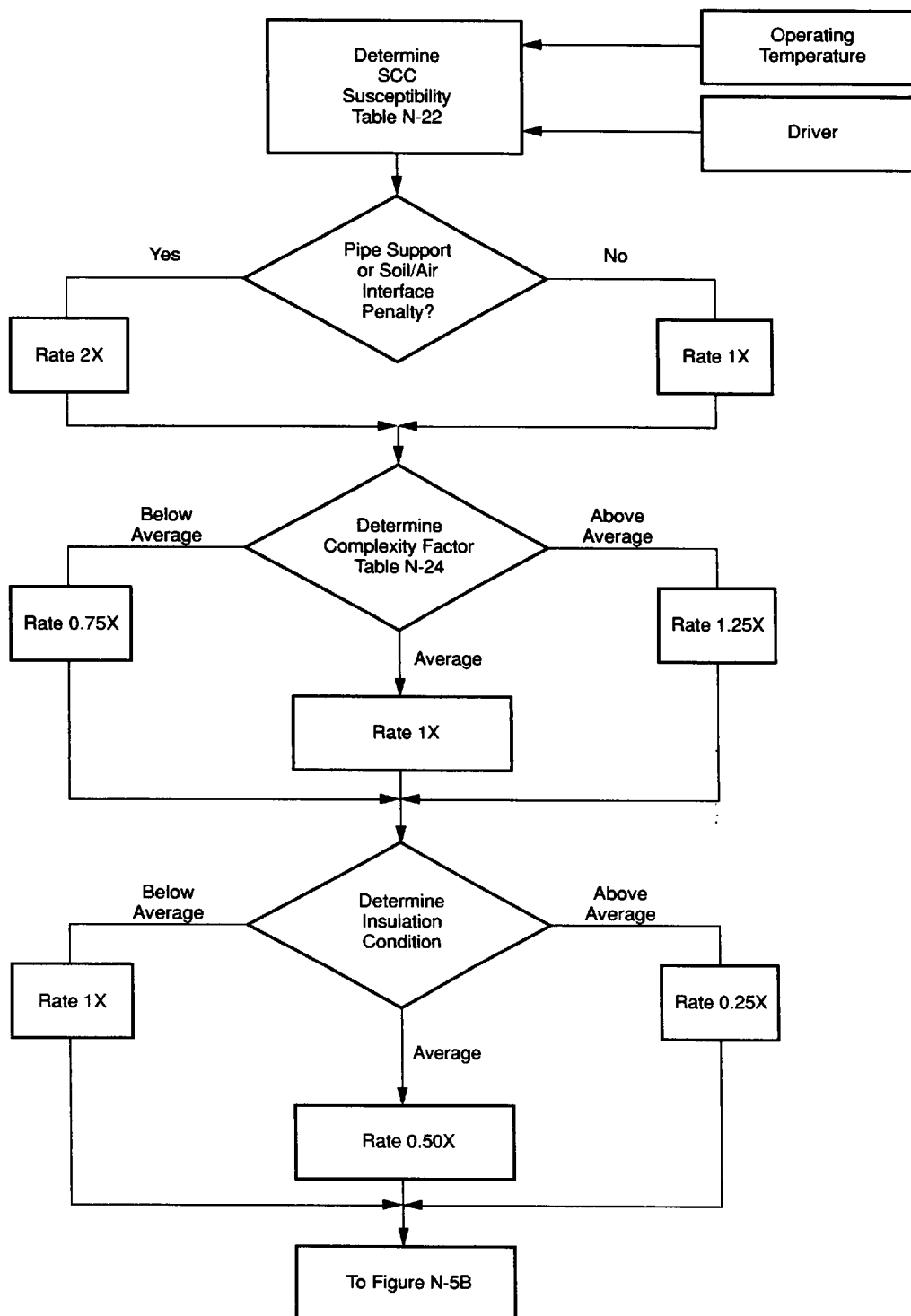


Figure N-5A—Flowchart of External CUI SCC for Austenitic Stainless Steels

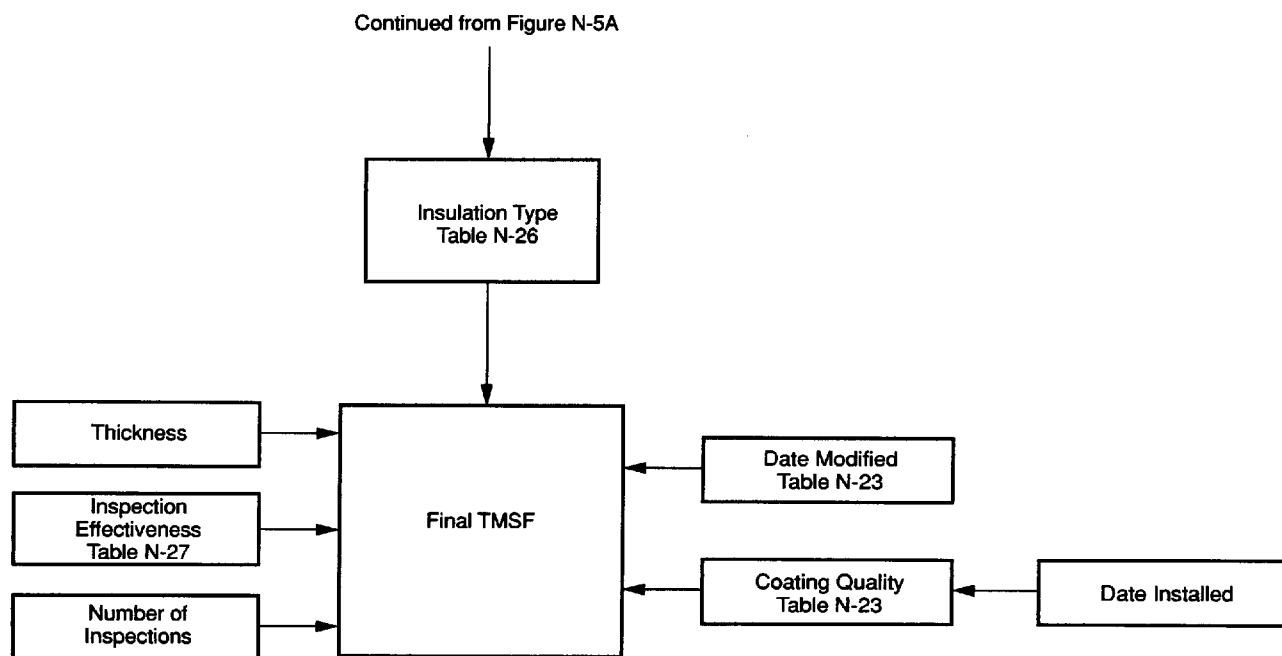


Figure N-5B—Flowchart of External CUI SCC for Austenitic Stainless Steels



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