FLAIM

Fire and Life Safety Assessment and Indexing Methodology

A Methodology for Assessing and
Managing Fire and Life Safety
for
Offshore Production Platforms

William E. Gale, Jr.
Robert G. Bea
Robert B. Williamson

Final Report to

U.S. Department of Interior
Mineral Mangement Service
Technology Assessment and Research Branch

UNIVERSITY OF CALIFORNIA at BERKELEY
COLLEGE OF ENGINEERING
OFFICE OF RESEARCH SERVICES
Contract Award Number 14515
(UCB Eng-7429)

January, 1994

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LIST OF SYMBOLS

β_{ij}: Binary value assignment for risk assessment i, question j. The binary value assignment for questions are represented by (Y/N) at the end of each question.

β_{ijk}: Binary value assignment for risk assessment i, question j, sub-question k. The sum of the binary value assignments for these sub-questions leads to a weighing assessment.

ω_{ij}: Weighted value assignment for risk assessment i, question j. Weighted value assignments may be direct input values or the sum of binary value assignments:

$$\omega_{ij} = \begin{cases} x & \text{for direct input assessments } (1 \leq x \leq 4) \\ \sum_k \beta_{ijk} & \text{for binary sub-questions} \end{cases}$$

ξ_{ijk}: Grade value assignment for risk assessment i, question j, sub-question k. The average of the sum of these grade values assignments for these sub-questions lead to a grade assessment for that question.

η_i: Grade Point Average (GPA) for fire or life safety assessment i.

$\eta_i^{\{l\}}$: Adjusted GPA for fire or life safety assessment i by implementing the set management alternatives {l}

$\Delta\eta_i^{\{l\}}$: Risk index differential measuring the difference between implementing the set of management alternatives {l} and no management alternatives.

α_{ijl}: Weighing change parameter is the ratio between of the new weighting value for assessment i, question j, and a single management alternative l and the prior weighting value ω_{ij} with no management alternatives.

$\alpha_{ij\{l\}}$: Weighing change parameter is the ratio of the new weighting value for assessment i, question j, and the set of management alternative {l} and the prior weighting value ω_{ij} with no management alternatives.

γ_{ijl}: Grading change parameter is the ratio of the new grading value for assessment i, question j, and a single management alternative l and the prior weighting value ω_{ij} with no management alternatives.

$\gamma_{ij\{l\}}$: Grading change parameter is the ratio of the new grading value for assessment i, question j, and the set of management alternative {l} and the prior weighting value ω_{ij} with no management alternatives.

$EC^{\{l\}}$: Cost of implementing the set of management alternatives {l} in current dollars.

$CI_i^{\{l\}}$: Cost index for fire or life safety assessment i and the set of management alternatives {l}.

κ_h: Consequence factor for platform h.

$\sigma_{\Delta\eta_i^{\{l\}}}$: Standard deviation of risk index differential for assessment i and set of management alternatives {l}.

$\sigma_{EC^{\{l\}}}$: Standard deviation for cost of implementing the set of management alternatives {l}.

$\sigma_{CI_i^{\{l\}}}$: Standard deviation for cost index for assessment i and set of management alternatives {l}.

Preface

FLAIM

Fire and Life Safety Assessment and Indexing Methodology

The idea for FLAIM, or at least its name, was conceived on the afternoon of January 23, 1992 in a conference room at the San Francisco international airport. In that meeting, Charles Smith, Program Manager, Operational Safety, Technology Assessment and Research Branch of the Minerals Management Service (MMS), suggested the acronym "FLAIM" for this (proposed) safety assessment methodology for existing production platforms. The concept for FLAIM evolved in 1991 as a result of discussions with Professors Williamson, Bea, Ashley, and Cornell-Paté (Stanford), and graduate students Bill Moore (UCB) and Peter Regan (Stanford). FLAIM follows in the footsteps of "AIM" (Assess, Inspect, Maintain) -- a program/methodology spearheaded by Professor R.G. Bea in conjunction with PMB Systems Engineering, Jack Spencer of the U.S. Coast Guard, and Charles Smith.[1]

FLAIM, as was AIM, is driven by the concern over ensuring continued safe operations of more than 4,000 aging oil and gas production platforms in U.S. waters, most of which are in the Gulf of Mexico (GOM) and are approaching an average age of twenty years. FLAIM's conception flowed from a MMS research program on the structural design for fires on offshore platforms.[2] It is generally recognized that older platforms are at greater risk to loss of containment events, and are more vulnerable to cascading event escalation. In recent years, life-extension and recertification of existing platforms has received increased attention, and significant advances have been made in the development of methodologies for assessing the overall level of risk failure and the effects of risk mitigation measures.[3] However, until FLAIM, a simple and adaptable methodology to assess fire and life safety risks associated with topside structures, accounting for both mechanical systems and management systems safety, has not been available.

FLAIM's development has drawn on resources from many areas in order to reach a consensus on an appropriate risk-screening technique. This technique is based on assessing the key risk contributors most often involved in significant offshore events. It is hoped that the users of FLAIM will further add to its versatility and comprehensiveness through an infusion of their own knowledge, offshore operating experience, and proprietary databases.

[1] Bea, R., Puskar, F., et al., *Development of AIM (Assessment, Inspection, Manitenance) Programs for Fixed and Mobile Platform*, OTC Paper # 5703, Offshore Technology Conference, Houston, May, 1988

[2] Bea, R., Williamson, R., and Gale, Jr., W., *Structural Design for Fires on Offshore Platforms*, Technology Assessment and Research Program for Offshroe Minerals Operations, 1991 Report, OCS Study MMS 91-0057, U.S. Department of the Interior, Minerals Management Service, p. 111

[3] Aggarwal, R., Bea, R., Gerwick, Jr., B., et al., *Development of a Methodology for Safety Assessment of Existing Steel Jacket Offshore Platforms*, OTC Paper # 6385, Offshore Technology Conference, Houston, May, 1990.

Introduction

This dissertation introduces a new methodology for assessing and managing safety of existing offshore oil and gas production platforms on the U.S. Outer Continental Shelf (OCS). The dissertation is organized into thirteen chapters and seven supporting Appendices, and includes a 3-1/2" micro-floppy disk on which the methodology software, "FLAIM," is presented.

Chapter One has been included to give the reader the general background information needed to fully understand the challenge of offshore oil and gas production safety management, and to lay the foundation for FLAIM's development. Supporting historical information on offshore platforms and fire loss data is provided in Appendix D.

Chapter Two presents an overview of FLAIM's methodology, and addresses issues relevant to the validity of the approach and the rational basis for its development. Included herein is a component diagram (flow diagram) of FLAIM's various components or modules which constitute the complete conceptual model. The diagram allows the reader to understand the relationships between the various model components and serves as a map to guide the reader through subsequent chapters.

Chapter Three addresses assessment of fire safety on offshore production platforms, and presents a systematic rationale for achieving risk management goals. This chapter includes a discussion of applying the Firesafety Concept Tree to offshore fire scenarios as a means of understanding the interaction among various risk factors and safety objectives.

Chapters Four through Seven detail FLAIM's components and associated risk factors comprising FLAIM's fire safety assessment procedure. They deal with the assessment of loss of containment (LOCA), vulnerability to escalation (VESA), layout and configuration (LACA), and operational factors (OHFA), respectively. Taken collective, these four chapters evaluate the mechanistic/material (hardware) aspects and front-line operational (human) aspects of platform operations by examining key fire risk contributors.

Chapter Eight covers the assessment of life safety. There are two separate components that address life safety risk factors: one module (LISAP) focuses on life safety aspects of the overall platform; the second module (LISAA) assesses the life safety features of the crew quarters (accommodations) as may be appropriate for the platform under consideration.

Chapter Nine accounts for specific platform design features/risk reduction measures (RIRA) which serve to mitigate the risk of fire and life-loss on the platform. FLAIM's design is intended to allow independent assessment of risk reduction measures and their impact on the overall topsides risk index. In this manner, the relative merits of various mitigation measures can be tested in terms of a what-if cost/benefit analysis or a disutility analysis using the indices as discriminators for reaching safety target levels.

In Chapter Ten, the human and organizational aspects of platform management are addressed by the Safety Management System assessment module (SAMSA). This module, which is composed of several module sub-sets, together with OHFA are considered to be among the most important components of FLAIM. They assess key risk factors in the administrative and management structure, and evaluate the overall organizational safety culture. Deficiencies in these areas are believed to account for up to eighty-percent of all serious offshore accidents.

Chapter Eleven presents the actual algorithm used in combining the various risk factors into a single topside risk index including a discussion on the relative weighting of each and the rationale used in their combination.

Using FLAIM's risk factors as meaningful risk management tools depends to a large extent on how the user ultimately "calibrates the risk meter." Chapter Twelve discusses the application of FLAIM's outputs and describes how users can best apply them for improving platform safety and managing risk. Understanding that, much like more complicated quantified risk assessment techniques, the main benefit to be derived is a relative understanding of risk on a comparative basis, Chapter Twelve encourages the user to consider FLAIM as a basis from which to build and mold in accordance with the experience and service demands of the platforms under consideration. In addition a procedure for performing cost-benefit analysis to evaluate fire and life safety risk management alternatives has been developed. The procedure incorporates the risk index methodology with decision making analysis techniques to provide the user with an effective decision support tool to optimize topside safety.

Chapter Thirteen concludes the main body of the dissertation with a summary of FLAIM and discussion of future research needs.

Detailed user instructions and an example for running FLAIM on a personal computer are given in Appendices A and C respectively. Appendix C presents an example of its implementation on a hypothetical offshore production platform (EXAMPLE PLATFORM) based on an actual platform design. These appendices address the steps involved in calculating the individual module risk factors and the overall topside risk index. An example of a computer generated worksheet is included for illustration in Appendix C.

Appendix B, consisting of eight subsections, is a complete listing of all risk factors that have been selected for incorporation into this first edition of FLAIM. These were selected based on an extensive review of accident case histories and the combined experience of several experts.

Appendices D and E provide historical information on accident case histories and a listing of the those reviewed in FLAIM's development.

Appendix F is a generic listing of causes leading to LOC events in processing facilities and Appendix G is a copy of the FLAIM source code.

Chapter One

OFFSHORE SAFETY MANAGEMENT

The focus of this work is on safety management of offshore hydrocarbon production platforms. The fundamental objective of the research and resultant methodology presented herein was to arrive at a practical and effective procedure for assessing and managing fire and life safety risks onboard existing offshore oil and gas production platforms common to the U.S. Outer Continental Shelf (OCS), both in the Gulf of Mexico (GOM) and Pacific regions. To be successful, assessment and management of risk must include not only design oriented issues of code compliance, e.g., hardware issues, but more importantly, issues directly germane to the root-cause of the preponderance of accidents offshore, e.g., human and organizational failures in the safety management system (SMS) and their operational manifestations.

There are considerable differences among offshore operators in their approach to platform safety.[1] Poor safety practices and programs are usually endemic to organizational problems rooted in lack of a strong "safety-culture." Further, the growing number of older platforms coupled with the rapidly increasing number of small independent operating companies in the Gulf of Mexico (GOM) can only be expected to exacerbate the divergence of safety-related problems.[2]

Following the now infamous Piper Alpha disaster (July 6, 1988) in which 167 people lost their lives in industry's worst offshore accident, numerous inquiries and research efforts were set in motion. In the ensuing official investigation,[3] Lord Cullen recognized a principal change was needed in administering U.K. offshore safety regulations -- a move away from prescriptive, mechanistic safety regulations to an approach based on goal setting objectives. Within the United States, a similar movement is taking place -- both onshore and offshore.

Following the October 23, 1989 Phillips Complex explosion and fire in which 23 worker were killed in what is deemed to be the largest onshore industrial accident in the U.S. of its kind,[4] Secretary of Labor Elizabeth Dole emphasized that "the most critical responsibilities for chemical process safety rest not with government agencies but with industry...."[5] Similarly, Assistant Secretary of Labor, Gerard F. Scannell, head of the U.S. Occupational Safety and Health Administration (OSHA), reported that "the primary causes of the (Phillips) accident were failures in management of the safety systems at the Houston Chemical Complex."[6]

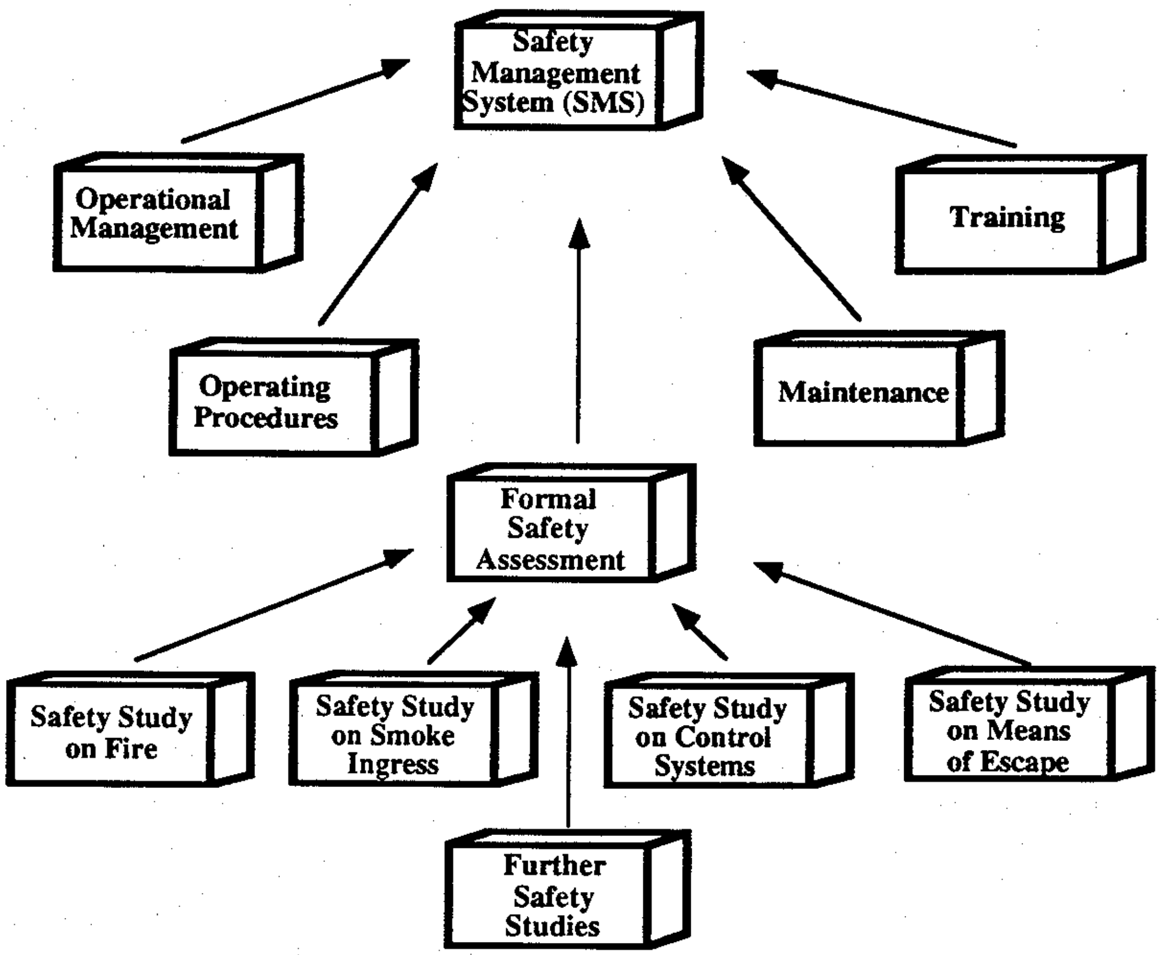

Figure 1-1

Interpretation of Safety Structure Proposed in the Cullen Report

Source: Interim Guidance Notes for the Design and Protection of Topside Structures Against Explosion and Fire, Steel Construction Institute SCI-P-112, Document No 243, January, 1992.

The Cullen Inquiry into the Piper Alpha accident developed 106 recommendations for, *in-so-far-as-is-reasonably-practical,* minimizing the exposure of platform personnel to accidental events and their consequences. In the case of Piper Alpha, the Safety Management System, e.g., the means to integrate and execute those aspects of platform design and operations that directly or indirectly influence achieving safe operating goals (**Figure 1-1**) was found to be deficient in several respects. This led to the present requirement for a formal safety assessment or "Safety Case," based on

Quantified Risk Assessment (QRA) techniques, to be included as part of the overall platform's SMS.[7]

The Cullen inquiry[8] of the Piper Alpha accident concluded that techniques based on Quantified Risk Assessment, also commonly known as Probabilistic Risk Assessment or "PRA," should be used to assess major hazards and to evaluate the means to reduce risk of accidental events on life safety features, e.g., the integrity of personnel refuge areas, escape routes, embarkation points and lifesaving craft, etc. However, as pointed out by the Fire and Blast Research Project's *Interim Guidance Notes,* [9] it is considered either impractical or impossible to carry out a rigorous QRA due to a lack of sufficiently detailed knowledge of the systems and their expected performance characteristics, or the lack of accurate probability data of initiating events, and the large uncertainties associated with determining consequences. Limited knowledge of probability distributions and limited/incomplete event databases have been and continue to be long-standing obstacles to rigorous application of QRA offshore.

Meaningful data needed for performing rigorous QRAs on most U.S. OCS platforms is also lacking. The present database maintained by Minerals Management Service (MMS) has been recognized as lacking in several respects. A report by the National Research Council[10,11] has recommended that MMS should develop a comprehensive system for collecting event and exposure date, calculating frequency and severity rates, analyzing trends, and performing several other functions necessary to produce usable data.

This problem is one of the driving forces that has led to the development of FLAIM -- a search for a means of integrating stochastic risk assessment approaches with deterministic and heuristic techniques to assess risk offshore -- to identify deteriorating operations (both from a mechanical and management standpoint) and reveal emerging safety risks on older platforms. FLAIM's development sought to capture one of the main advantages of QRA -- the application of a quantified and structured approach to enable decisions to be reached on a rational and consistent basis -- but yet greatly simplifies the assessment procedure and eases the burden of performing such studies. FLAIM is not intended to replace more thorough risk assessment techniques, however, but rather complement their usage when appropriate (and when meaningful data are available). FLAIM is primarily intended to provide a screening tool for platform operators and regulators to help them determine how to best improve existing safety management programs and direct limited resources for optimal risk mitigation.

Aside from the lack of data, however, is the question of need. Are detailed and costly quantified risk assessment studies an effective approach or sound investment to protect U.S. OCS resources -- human, mineral, and environmental? Or could a greater return be realized by directly investing the same money in risk reduction measures that address known problems?

In a joint study[12] performed by the Danish Energy Agency and Maersk Oile og Gas, North Sea facilities were compared to GOM platforms. The study showed several fundamental differences in design philosophy, many of which could not be attributed solely due to the differences in environmental operating conditions. North Sea platforms are in general much more sophisticated and complex. They are highly compartmentalized and subdivided into fire zones using fire walls as opposed to open deck GOM platforms, and have much more sophisticated fire control and shutdown systems, and have much higher levels of manning. They also cost more than GOM platforms by a factor of five.

The study sought to determine if the simpler and less expensive GOM platform designs, with simpler safety provisions, e.g., hose lines v. deluge systems, were subject to greater fire and life safety losses. Based on information from WOAD[13] data for the period of 1980-1987 (pre-Piper Alpha) for fixed platform operations was analyzed. It was found that the number of accidents for GOM platforms was almost exactly one order of magnitude <u>lower</u> than that for North Sea platforms (8.7 v. 87.05 accidents/1000 operating years), and that lives lost was lower by a factor of more than twelve.[14] These results reflect the wisdom of the general recognition by GOM operators of the "**KISS**" philosophy as long propounded by Professor R.G. Bea -- **Keep It Simple and Serviceable.**

Many industry experts in the U.S. agree that a formalized U.K.- style "Safety Case" approach as proposed by Cullen is not generally necessary, practical, nor merited for U.S. OCS platforms.[15] Further, Arnold argues that, most of the types of incidents accounting for losses on existing platforms in U.S. waters do not justify performing detailed Hazard and Operability Studies (HazOps) and the subsequent risk analyses required to identify hazards and decide among various recommended remedies.[16]

In many cases, detailed systems-oriented hazard analysis techniques are abbreviated by those performing the analysis due to either inexperience or intentionally, as a result of the repetitious and time demanding nature of these exercises. Further, since many events occurring on the OCS are not directly related to failure of a safety device, it is likely that the unrecognized problem areas that are most often causing accidents may be overlooked or otherwise dismissed as not being of credible, significant, or as otherwise preventable by operator response.

Within the Unites States during the post-Piper period, much research and regulatory attention has been focused on issues of process safety management for both onshore and offshore hydrocarbon handling facilities. Most recently, the Department of Labor's Occupational Safety and Health Administration (OSHA)[17] has largely adopted as law the American Petroleum Institute's Recommended Practice, *Management of Process Hazards*,[18] for the regulation onshore petroleum facilities.

The new OSHA process safety management requirements were promulgated as a direct result of the 1989 Phillips Complex explosion and fire.[19] Labor Secretary Elizabeth Dole noted that "the catastrophe at Phillips' complex underscores the need for effective implementation of good safety management systems in the petrochemical industry," and cited as primary contributors to the problem a lack of attention to: 1) recognition of hazards, 2) poorly maintained equipment, 3) poor planning, and 4) unsafe work practices.

Recognizing the importance of addressing human factors and operational errors in process safety management, OSHA's new regulations focus attention on the contribution of human factors in process hazard analysis.[20] As pointed out by Fleger, industry is now coping with the problem of how to perform human factors analysis as a part of the mandated process hazard analyses required by 29CFR1910.119. Fleger notes that quantitative techniques, such as Human Reliability Analysis (HRA) are even more cumbersome than many types of other quantitative analyses, and suffers from the same limitations of uncertainties due to a lack of specific data or human error probabilities.[21]

The petroleum industry is greatly concerned that in questions of process hazards analysis adequacy, the courts may determine that QRAs for human factors should be performed, similar to that required in the nuclear industry.[22] As already noted, U.S. industry experts generally agree that quantified hazards analysis and human factors analysis is not generally necessary, practical, nor merited for U.S. OCS platforms.[23] Industry experts argue that the adequacy of a platform's safety management system can be effectively assessed, monitored, and improved using simpler techniques, such as those proposed by the American Petroleum Institute.[24]

As of this writing, a new recommended practice is being developed by API for offshore production platforms.[25] The recommendations of this publication are most likely to be adopted by the U.S. Mineral Management Service as a part of the OCS Orders.[26, 27] API is seeking to establish clear and effective guidelines for the development of safety management and environmental management programs for platforms operating in U.S. waters.

Concurrently with RP-75, API is finalizing a new companion publication, API RP 14J, that provides guidance on performing hazards analysis on open-type production platforms.[28] This publication will provide, *inter alia*, a listing of considerations and factors that should be accounted for in performing hazard analyses in a checklist format.

FLAIM was developed to provide the framework and a methodology that integrates both human factors and design considerations into a unified approach for assessing and managing platform safety. FLAIM's aim is focused on providing an effective means for executing and implementing safety management goals consistent with the needs and loss experience of the OCS production platforms.

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[1] *Alternatives for Inspecting Outer Continental Shelf Operations*, Committee on Alternatives for Inspection of Outer Continental Shelf Operations, Marine Board, Commission of Engineering and Technical Systems, National Research Council, National Academy Press, Washington, D.C., 1990, p. 80

[2] Arnold, K., et al., *Improving safety of production operations in the U.S. OCS*, World Oil, July, 1990, p. 63

[3] Cullen, The Hon. Lord, The Public Inquiry into the Piper Alpha Disaster, U.K. Department of Energy, vols. I & II, HMSO Publications Centre, London, November, 1990

[4] *The Phillips 66 Company Houston Chemical Complex Explosion and Fire*, Report to the President, U.S. Department of Labor, Occupational Safety and Health Administration, April, 1990

[5] NEWS, U.S. Department of Labor, Office of Information, USDL 90-207, April 26, 1990

[6] Ibid.

[7] Lees, F.P., and Ang, M.L., *Safety Cases*, Butterworths Publishing, London, 1989

[8] Cullen, The Hon. Lord, op. cit., pp. 275-336 & 387-390

[9] Interim Guidance Notes for the Design and Protection of Topside Structures Against Explosion and Fire, Steel Construction Institute (U.K.) SCI-P-112, Document No 243, January, 1992., p. 1.3, paragraph. 1.3.3

[10] *Alternatives for Inspecting Outer Continental Shelf Operations,* Committee on Alternatives for Inspection of Outer Continental Shelf Operations, Marine Board, Commission on Engineering and Technical Systems, National Research Council, National Academy Press, Washington, D.C., 1990, p.83

[11] Arnold, K. and Koszela, P., Improving *safety of production operations in the U.S. OCS,* World Oil, July, 1990, p. 64

[12] Bill, F. and Goldschmidt, L., *Safety Through Separation and Simplicity,* Fire Safety Engineering -- Proceedings of the 2nd International Conference, Danish Energy Agency, (Chapter 7), pp. 71-86

[13] Veritec, Worldwide *Offshore Accident Databank, Statistical Report, 1988,* Hovik, 1988, ISSN 0801-5929]

[14] Bill, F. and Goldschmidt, L., op. cit., p.77, Table 1 and p. 78, Table 2

[15] "Reliability of Offshore Operations: Proceedings of an International Workshop, NIST Special Publication 833, U.S. Dept. of Commerce, April, 1992, Working Group #4, Production Facilities, pp. xviii, 138-141

[16] Arnold, K. and Sikes, C., *Generic HazOp Would Improve Gulf of Mexico Process Safety,* ,World Oil, November, 1991, pp. 63-64

[17] U.S. Code of Federal Regulations, 29CFR 1910.119, *Process Safety Management of Highly Hazardous Chemicals,* February, 1992

[18] American Petroleum Institute, Recommended Practice 750 (RP 750), *Management of Process Hazards,* First Edition, January, 1990

[19] *OSHA to step up process safety program,* Oil & Gas Journal, May 7, 1990, p.32

[20] Fleger, S.A., *Human Factors Analysis Useful for Process Safety Management,* Occupational Health & Safety, Medical Publications, Inc. Waco TX, March, 1993, pp. 24-32

[21] Ibid., P. 31

[22] Ibid., p. 27

[23] "Reliability of Offshore Operations: Proceedings of an International Workshop, NIST Special Publication 833, U.S. Dept. of Commerce, April, 1992, Working Group #4, Production Facilities, pp. xviii, 138-141

[24] Arnold, K., and Roobaert, N., Actions Needed to Comply With API RP 750, Management of Process Hazards for Offshore Facilities, Society of Petroleum Engineers, Paper No. SPE 22803, 1991

[25] American Petroleum Institute, Recommended Practice 75 (RP 75), Recommended Practice for Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities, American Petroleum Institute, Eight Draft, November, 1992

[26] U.S. Code of Federal Regulations, 30CFR Parts 250, *Oil, Gas and Sulphur Operations in the Outer Continental Shelf*

[27] private correspondence -- letter from Mr. Ken Arnold, Chair of API RP 14J Task Force to Dr. Tariq Al-Hassan, U.K. Health & Safety Executive, August 12, 1992

[28] American Petroleum Institute, Recommended Practice 14J (RP 14J), *Design and Hazards Analysis for Offshore Production Facilities,* American Petroleum Institute, October, 1992 DRAFT

Chapter Two

FLAIM -- BACKGROUND AND OVERVIEW

2.1 *BACKGROUND OF FLAIM'S CONCEPTION*

Following the loss of Piper Alpha, the Mineral Management Service requested the National Academy of Sciences' Marine Board to assist them in investigating alternative strategies for the inspection and safety assessment of OCS platforms, with a view towards improving operational safety and inspection practices.[1] Considerable effort was made to select members of the working committee, known as the Committee on Alternatives for Inspection (CAI), who not only had both the requisite expertise in OCS operations and safety management, but also would bring a balanced viewpoint with respect to public interests in environmental protection and safety.

CAI members reviewed the current OCS inspection program and practices, appraised other inspection practices for "lessons-learned," including those of platforms in state waters as well as inspection practices in other industries (nuclear, etc.), reviewed MMS data bases and the OCS safety record, and developed evaluation criteria and alternative recommendations for consideration by MMS. Alternative approaches were evaluated against the following criteria:

- does the alternative promote safety awareness
- does it foster public confidence in the safety of OCS operations
- does it use inspection resources efficiently
- what impact does it make on the qualifications and training of inspectors
- does the program provide for identification of safety trends and warnings
- does it promote safety performance accountability
- is it adaptable to changing circumstances
- are there valid precedents

Further, the CAI noted that improvements in safety performance are derived largely from past experience (lessons-learned), and found that the MMS database on OCS operations must be made more comprehensive and accessible in the future to promote inferential analysis and more precise safety assessments. The CAI recommended the database focus on the cause of OCS accidents <u>that actually are experienced, and their</u>

early warning signals, so that analysis based on improved data would be possible with higher confidence.

The CAI developed an alternative inspection recommendation (*Alternative 3*) based on developing **quantitative indices that characterize and measure the safety of individual offshore operations**. Several factors were identified that should be taken into account in developing sampling indices to characterize and measure platform safety, including:

- the occurrence of safety-related events onboard the platform
- the occurrence of near-misses which could have caused an accident
- the record of tests and inspections of safety equipment found in ill-repair
- evidence of slipshod operation, e.g., poor maintenance, poor housekeeping, poor record keeping, etc.
- the facility design, such as location and age
- evidence of lax safety attitudes of managers, supervisors, or operating personnel, e.g., the safety "culture" and awareness factor
- the overall safety record for all platforms operated by the operator
- the overall safety record for all operators with the region of operations

CAI suggested that from such quantitative, facility-specific information, a safety rating could be developed for each platform which would be updated continually with new data. The data base would be kept up to date by requiring that all event reports and specified operator's inspection and test results be sent to MMS. Onshore review of records could then comprise a substantial part of the inspection and assessment process, and onsite inspections (offshore) could be accomplished in a much more efficient and informed manner based on prior analysis of the information in the data base.

Finally, the CAI stressed the importance of management's safety culture and suggested that MMS make explicit in its safety management and inspection philosophy the monitoring of safety attitudes of the operators essential, recognizing that subjective judgments will be involved in this process. However, CAI pointed out that subjective judgments should not be a deterrent, but rather MMS inspectors and supervisors should be trained in techniques for and the importance of monitoring safety attitudes.

The CAI cautioned against "compliance mentalities" in which some operators may perceive their responsibility and objective as to "simply pass inspection." CAI emphasized its belief that mere compliance with requirements/regulations *does not equal safety,* and that in practice and by law, the operators bear the primary responsibility for safety. MMS's responsibility is to find the best and most effective means it can devise to motivate operators to meet their responsibility.

FLAIM's conception is rooted in all of the foregoing CIA principles and findings. FLAIM development was geared to meeting the identified criteria, in recognition of the need to fulfill a variety of functions to be successful. Foremost, it must be user-friendly, interactive, and pleasant to use -- with the goal of **motivating platform operators** to monitor and manage the ever-change state of safety onboard their platforms, rather than represent a burdensome and arduous task that is both time consuming and overly technically demanding. It must promote safety performance accountability in an efficient and effective manner.

Further, FLAIM was designed to be adaptable for use to both specific applications as well as specific operators who, hopefully, will choose to use their own proprietary and confidential databases to identify those risk contributors of most significance to the particular operations under scrutiny. In this regard, FLAIM does not presuppose that the risk contributors and their corresponding weighting algorithms used in this original work are absolute or rigid, but rather provisions have been purposefully designed to allow users to select, add, and change the values used herein, e.g., FLAIM is intended to serve as the basis for developing site-specific models suited for the particular area and nature of operations, facility design, reservoir characteristics, and service demands for any given platform. Therefore FLAIM incorporates features that both explain the logic used in its development and allows modification of factors and algorithms when deemed suitable for the user. FLAIM is intended as a tool for platform operators -- to assist them in meeting their safety goals and responsibilities -- using their own databases, knowledge, and experience, as well as those existing at large within industry to do so.

FLAIM's design was developed in recognition of the significant role that human and organization error (HOE) plays in promoting offshore accidents, while accounting for the fact that older topside systems, besieged by years of demanding service under harsh conditions, can be expected to have higher rates of mechanical/material related failures than their newer counterparts. FLAIM identifies and permits the selection of known risk contributors to assess and quantify platform operations, placing heavy emphasis on safety management systems, their effective implementation, and the safety culture under which the platform is functioning.

FLAIM has sought to meet CAI's criteria for "valid precedents," and builds on concepts that have been successfully employed by major onshore petrochemical companies and fire safety authorities for over 25 years, using risk indices to measure and assess life safety and fire safety risks. The application of these techniques to offshore platforms was guided by principles established by the National Fire Protection Association for developing logic trees as a means to reach safety goals.

In a working document prepared for the API 14J committee, J. Frank Davis of Shell Oil Company suggested the use of risk index methodologies as "an excellent way to prioritize process hazards management activities in a relative sense."[2] It should be noted that at the time of receiving this information (September, 1992), the concept for FLAIM had already been independently developed and research work was well underway (refer to Preface). Subsequent discovery by the author of the American Petroleum Institute RP-14J committee's work in this area serves to further substantiate the validity of FLAIM's approach.

It is recognized, however, that FLAIM, being newly conceived and developed, will need to evolve and mature based on application and feedback from its intended users, e.g., platform operators, regulators and inspection authorities, underwriters, and offshore contractors. FLAIM, as any measuring tool, requires calibration for the particular circumstances in which it is intended to function. Therefore, it is with this understanding, and a desire to contribute to the further enhancement of offshore operations, that the FLAIM computer code and methodology is being freely offered without restriction to all those wishing to make use of this safety assessment methodology.

2.2 *DESCRIPTION OF FLAIM*

FLAIM can best be described as a quantitative risk assessment indexing methodology in which selected key factors relevant to fire safety and life safety are identified, assessed and assigned numerical (weighting) values. Risk contributing factors are thereby indexed and ranked using a weighting system algorithm, keyed to relative (comparative) risk, to yield a set of risk indexes, and an overall risk index for topsides facilities. For familiarity and ease of use, an academic letter grading scheme (A, B, C, D, F) based on a 4.0 grade-point scale was selected as the framework for assessing risk contributors.

Key topsides risk factors, identified on the basis of scenario analysis, expert opinion, and historical records, can be selected and evaluated by the user together with provided or planned for risk reduction measures. Life safety is assessed independently from fire safety, using risk factors specific to each, but accounting for their close interdependence . The adequacy of risk reduction measures and the overall platform Safety Management System (SMS) can be assessed by calculating the RIRA and SAMSA indexes. These indexes reflect provision of risk mitigating and safety management status of the facility. They are combined with fire safety and life safety indices in order to arrive at an overall *topside risk assessment index.*

Figure 2-1, *Primary Modular Components Used to Develop FLAIM,* and **Figure 2-2,** *FLAIM Assessment Procedure,* illustrates the modular components used to develop FLAIM's assessment and indexing model and their relationship. **Figure 2-2** serves as an overall "road-map" to FLAIM's methodology, and may be of particular usefulness in relating the descriptive chapters to the assessment procedure. FLAIM's model development was an outgrowth flowing from the logic set forth in the National Fire Protection Association's (NFPA) Fire safety Concepts Tree which was useful as a basis for the sequential analysis of platform risks as described herein.[3]

Various indexing methodologies for safety assessment have been in use for many years, having their origin in the insurance underwriting industry where they are sometimes referred to as fire risk assessment schedules. Some of these approaches are well established and have been applied to the petroleum/petrochemical processing industries,[4] such as the Dow Fire and Explosion Index[5] as discussed below. Other indexing schemes, such as Muhlbauer's approach[6] for pipelines, are relatively new and remains to survive the test of historical validation. Several of these methodologies have been reviewed in formulating FLAIM's approach, including:

2.2.1 The Dow Fire and Explosion Index[7]

2.2.2 The Mond Fire, Explosion, and Toxcitity Index [8, 9, 10]

2.2.3 Purt's Method[11]

2.2.4 Gretener's Method[12]

2.2.5 Nelson's Fire Safety Evaluation System[13]

2.2.6 Muhlbauer's Risk Management Index for Pipelines[14]

2.2.7 The International Loss Control Institute's International Safety Rating System[15]

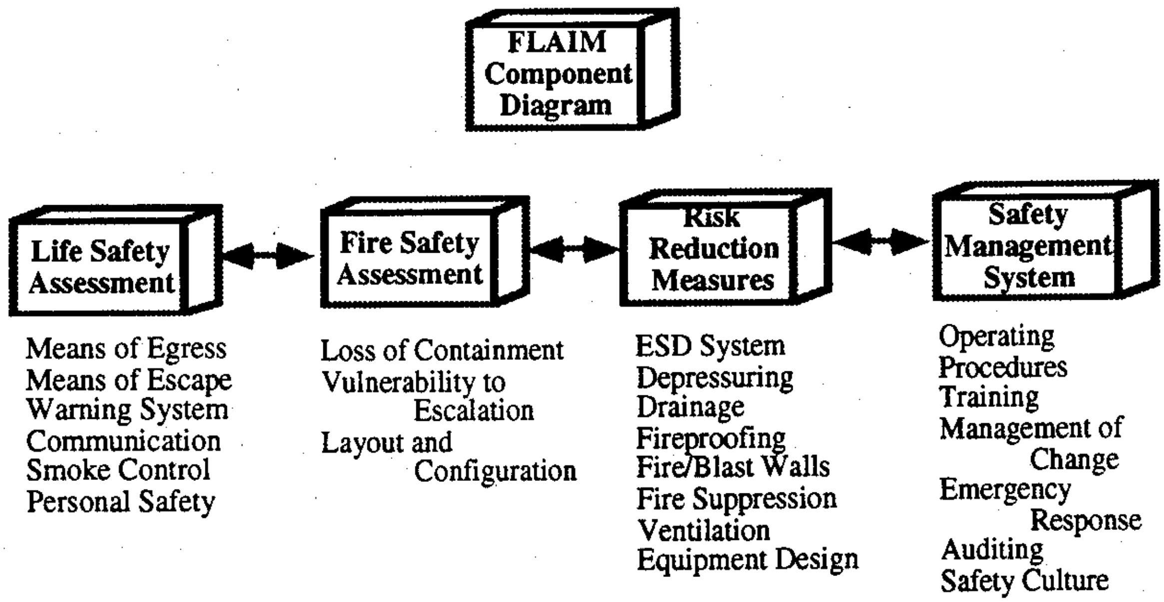

Figure 2-1

Primary Modular Components Used to Develop FLAIM

2.3 *INDEXING METHODOLOGIES IN GENERAL*

Professional judgment, historical records, past experience, and in some cases predictive hazard evaluation techniques (e.g. Event Tree Analysis (ETA), Hazard and Operability Studies -- "HAZOPs," etc.) are used by indexing methodologies to identify and select key variables (risk contributors and risk mitigators). These are then combined by using various algorithms to yield risk indices indicative of the state of the facility and its management system. An overall risk index can be also generated to compare different facilities in a relative manner, providing insights to judgments on risk preferences and priorities, as well as facilitate the cost-benefit analyses for risk mitigating measures.[16, 17]

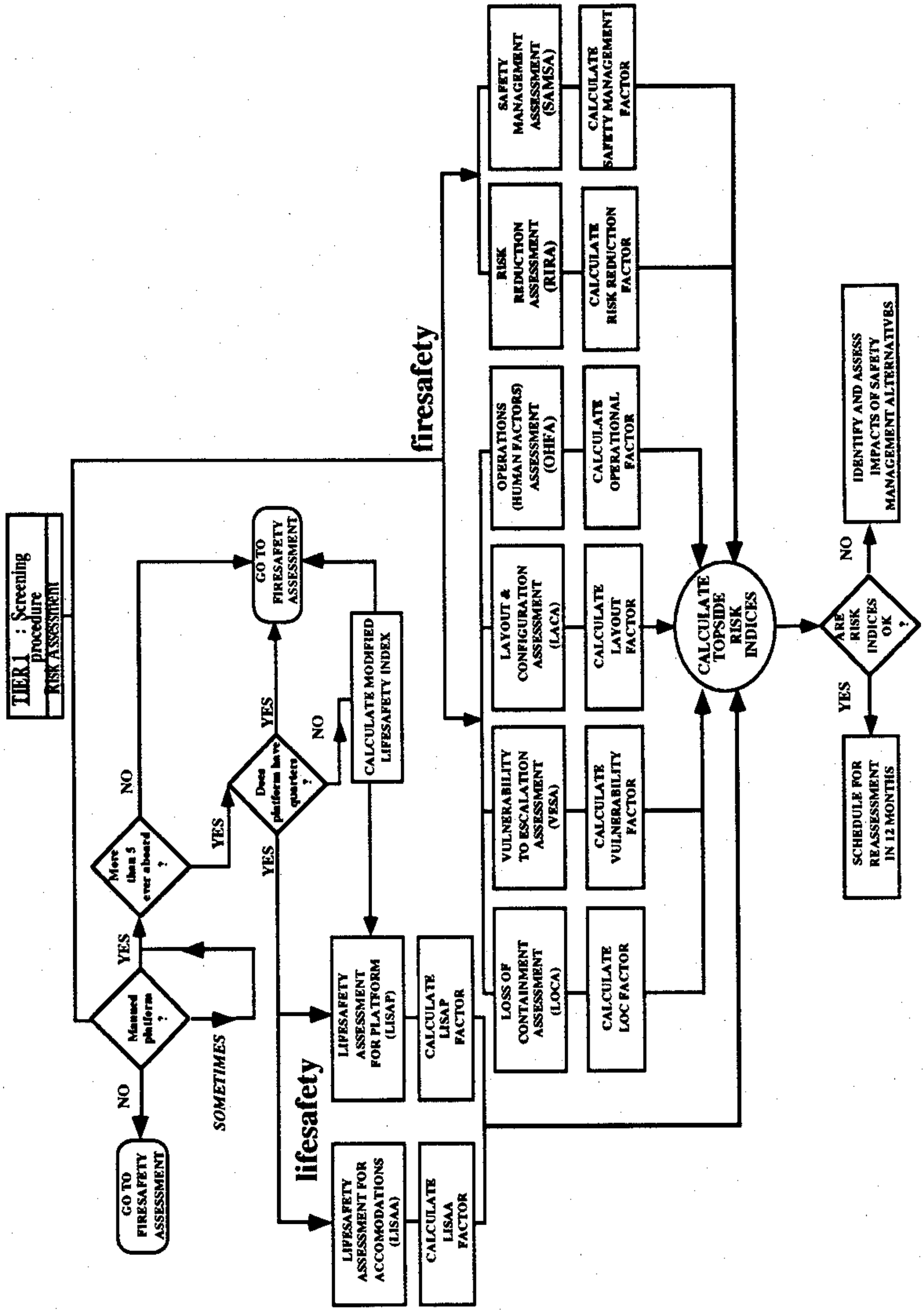

Figure 2-2

FLAIM Assessment Procedure

The Dow Fire and Explosion Index (F&EI) is perhaps the oldest and most widely recognized hazardous facility oriented indexing methodology in use today. The first edition of the Dow's *Fire & Explosion Index Hazard Classification Guide*, published nearly thirty years ago in 1964, was a modified version of an insurance industry methodology, the *Factory Mutual Chemical Occupancy Classification Guide*. Over the years, refinements in Dow's indexing methodology and improvements in quantitative correlation were made to arrive at the current edition.

The Dow F&EI seeks to quantify the expected damage of potential fire and explosion incidents in realistic terms, identify equipment that would likely contribute to the initiation or escalation of an incident, and to communicate the fire and explosion risk potential to management. The quantitative measures employed in the analysis are based on historic loss data, the characteristics of the materials being handled, and the extent to which loss prevention practices are applied in the facility under consideration. Professor Frank Lee of Loughborough University of Technology observes[18] that the Dow F&EI is widely used as an aid to the selection of fire preventive and protective features, and is a well proven method.

The Dow F&EI has proven to be an effective tool for evaluating hazards during process development, site selection, and plant layout, and can be used as a model for developing other risk screening techniques for prioritizing and ranking plant risks.[19] Dow Chemical believes that their fire and explosion indexing methodology is, in fact, equivalent to those cited in the new OSHA process regulations (29CFR1910.119) and will continue to rely on this approach to satisfy process hazards analysis requirements.[20] This was an important consideration in carrying forward the development of FLAIM.

Dr. John Watt, editor of NFPA's Fire Technology, has observed that fire risk schedules (indexes) have the advantage of high utility due to their relative ease of preparation, but may lack validity due to the unspecified nature of the selection of variables and their relationship.[21] Watt opines that a desirable objective is to generate a schedule (indexing methodology) by the selection of variables in a manner that is rational, logical and inherently reproducible to achieve a means or risk evaluation sufficient in both utility and validity. It is with recognition of this objective that FLAIM has been developed.

FLAIM's development sought to avoid such criticism insofar as possible by carefully establishing the relationship of the selected variables, the historical record, and the chosen risk factor's relationship to topside risk using established logic networks, vis-á-vis, NFPA Fire safety Concepts Tree.[22] However, as exemplified by the Dow F&EI, FLAIM's utility must ultimately be subjected to demonstration testing and feedback in order to achieve a comparable consensus.

In this regard, FLAIM's development included reviewing and assessing risk factors identified in various studies of petroleum handling facilities, such as in the study entitled *Facility Assessment, Maintenance and Enhancement* (FAME),[23] which was sponsored by the U.S. Minerals Management Service (1992) in response to the Marine Board's CAI recommendation calling for improved accident databases. FAME's work included developing a listing of several key topside risk factors, but stopped short of the goal for developing an assessment methodology.

In fact, in a sense FLAIM may be viewed as Task 4 of the FAME study, e.g., the development of a methodology to perform a requalification audit of a facility and its operation, which went unpursued for lack of funding. It is interesting to note, however, that while FAME and FLAIM both flowed from Professor's Bea's original work on AIM, the idea for FLAIM had been conceived independently of and without knowing about the FAME study, a copy of which was received in September, 1992 courtesy of Mr. Ken Arnold, Chair of the API RP-14J committee and President of Paragon Engineering Services.

Another attribute of index risk assessment methodologies worthy of note is their implicit inclusion of the concept of fire safety and life safety goals to achieve a desired level of safety. This is completely consistent with the Cullen findings, and avoids prescriptive formulation of risk reduction measures.

A significant part of the research associated with development of the methodology proposed herein has been to reduce the inordinately large number of potentially significant risk contributors and mitigators to as few meaningful descriptors as possible without eliminating key variables from the equation. This was accomplished through the use of scenario-based analysis and a review of hundreds of offshore accident case histories (see Appendix E), together with the application of judgment and experience. Nevertheless, as can be seen in Appendix B, the number of potential risk contributors identified for consideration is extensive. FLAIM has been designed with the intended purpose of allowing users to select and weight the value of input parameters to the algorithm in accordance with the particular operating conditions, experience, and risk-preferences appropriate for the platform and management structure under consideration. It is believed that in most cases a relatively small number of key risk contributors will largely control the overall level of fire and life safety risk on a platform.

In this regard, Watts[24] believes that it is not only intuitively appealing to postulate that safety from fire is a Paretian[25] phenomenon, e.g., that a relatively small number of factors account for most of the problem, but that indeed this is supported by general fire loss figures, which suggest that a small number of factors are associated with a large proportion of fire deaths.[26, 27] However, as Watt cautions, and as already discussed, statistical data available for such analyses is often limited, and subjective selection is an important component in the selection process.

The risk contributing factors and assessment procedures enumerated herein are those that have been judged to be of greatest significance to the safety of existing offshore oil and gas production platforms operating in the GOM, recognizing the importance of safety management systems and the safety attitude of the operator. They should not be considered to be absolute, nor static, and it is intended that as with other established indexing procedures, each future user of FLAIM will contribute to "fine-tuning" the methodology.

The factors selected in FLAIM's various assessment elements are those believed to be most relevant to those types of events that have been found to reoccur with regularity and with potentially significant consequences. In accordance with Arnold, a significant portion of these events may not be relevant to the focus of existing MMS inspection methods, but rather result from safety management system related-factors. FLAIM is designed to fulfill the large voids left by other risk assessment techniques that, for example, are primarily process-hardware oriented to the exclusion of other, more significant risk contributors rooted in human and organizational factors.[28]

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[1] *Alternatives for Inspecting Outer Continental Shelf Operations*, Committee on Alternatives for Inspection of Outer Continental Shelf Operations, Marine Board, Commission of Engineering and Technical Systems, National Research Council, National Academy Press, Washington, D.C., 1990

[2] personal correspondence w/ Mr. K.E. Arnold, Chair of API RP-14J Task Force and President of Paragon Engineering Services Inc., Houston, September 16, 1992

[3] NFPA 550, *Guide to Firesafety Concepts Tree*; National Fire Codes, National Fire Protection Association, Quincy, MA, 1986, also see, Nelson, H., *Directions to Improve Application of Systems Approach To Fire Protection Requirements for Buildings,* SFPE Technology Report 77-7, Society of Fire Protection Engineers, Boston, 1977

[4] Mallett, R., *Rate your risk management plans,*. Hydrocarbon Processing, August, 1992, pp. 111-115

[5] American Institute of Chemical Engineers, Fire *& Explosion Index Hazard Classification Guide,* Sixth Edition, A Chemical Engineering Progress technical manual, AIChE, N.Y., N.Y., 1987

[6] Muhlbauer, W., Pipeline Risk Assessment Manual, Gulf Publishing Company, 1992

[7] American Institute of Chemical Engineers, op. cit.

[8] Lewis, D., *Loss Prevention Activities and the Potential Contribution of the Mond Index Technique*, from a course at Loughborough University, U.K., January, 1992, courtesy of Professor Trevor Kletz in personal correspondence with the W. Gale

[9] Lewis, D., The *Mond Fire, Explosion and Toxicity Index -- A Development of the Dow Index,* presented at the 1979 Loss Prevention Symposium (Houston), American Institute of Chemical Engineers, N.Y.

[10] Lewis, D., The *Mond Fire, Explosion and Toxicity Index Applied to Plant Layout and Spacing,* Loss Prevention, a Chemical Engineering Progress technical manual, American Institute of Chemical Engineers, Vol. 13, 1980, pp. 15-19

[11] Purt, G., *The evaluation of the fire risk as basis for the planning of automatic fire protection systems,* presented at the sixth international seminar for automatic fire detection, IENT, Aachen, October 4-6, 1971, pp. 204-231

[12] Kaiser, J., *Experiences of the Gretener method,* Fire Safety Journal, Vol. 2, 1980, pp. 213-222; also see BVD, *Evaluation of Fire Hazard and Determining Protective Measures,* VKF/BVD, Zurich, 1973

[13] Nelson, H,, and Shibe, A., *A System for Fire Safety Evaluation of Health Care Facilities,* NBSIR 78-1555, Center for Fire Research, National Bureau of Standards, Washington, 1980

[14] Muhlbauer, W., op. cit.

[15] *ESSO Petroleum Canada's IOCO Refinery and the International Safety Rating System,* American Petroleum Institute (API) Committee on Safety and Fire Protection, COSFP Technical Paper # 2324, presented at the 1986 Fall Meeting in Fort Lauderdale, Florida, September 16 - 18, 1986

[16] Mallett, R., *Rate your risk management plans,* HYDROCARBON PROCESSING, August, 1992, p.111

[17] Ozog, H., and Bendixen, L., *Hazard Identification and Quantification,* Chemical Engineering Progress, April 1987, pp. 55-64

[18] Lee, F.P., Loss Prevention in the Process Industries, Volume 1, *Hazard Identification, Assessment, and Control,* Butterworth & Co. (Publishers) Ltd., London, 1980, p. 530

[19] Ozog, H., and Bendixen, L, op. cit.

[20] Barns, D., *Process Safety: Dow Chemical USA Finds the Standard's Positive Side*, Occupational Health & Safety, October, 1992

[21] Society of Fire Protection Engineers, The *SFPE Handbook of Fire Protection Engineering*, National Fire Protection Association, 1988. pp. 4-89 to 4-102

[22] National Fire Protection Association, op. cit. Guide to the Firesafety Concepts Tree

[23] Visser, R.C., *Introductory Study to Develop the Methodology for Safety Assessments of Offshore Production Facilities*, prepared for MMS by Belmar Engineering, Redondo Beach, CA, August, 1992

[24] Society of Fire Protection Engineers, op. cit., *The SFPE Handbook*

[25] C.J. Slaybough, Pareto's Law and Modern Management, Management Service. 4, March-April, 1967

[26] Clarke, F.B., and Ottoson, J., *Fire Death Scenarios and Fire Safety Planning*, Fire Journal, 70, 3, 1976

[27] Visser, R.C., op. cit., for example, Visser found that two-thirds of all fires and explosion accidents occur on platforms on which a gas compressor is located, resulting in a 4% annual fire risk compared to 0.5% annual risk for platforms without gas compressors

[28] Arnold, K, op. cite, *Improving safety of production operations in the U.S. OCS*

Chapter 3

FIRESAFETY ASSESSMENT

3.1 *SYSTEM SAFETY ANALYSIS FOR FIRE & LIFE SAFETY GOALS*

The management of fire risks on offshore production platforms has been evaluated using system safety concepts developed by the National Fire Protection Association.[1] Key risk contributors were identified using the firesafety concepts decision tree as a basis for achieving (success in meeting) risk management goals.

There are two primary independent branches to the decision tree leading to successfully meeting safety objectives (**Figure 3-1**):

- Prevention of Ignition
- Management of Fire Impact

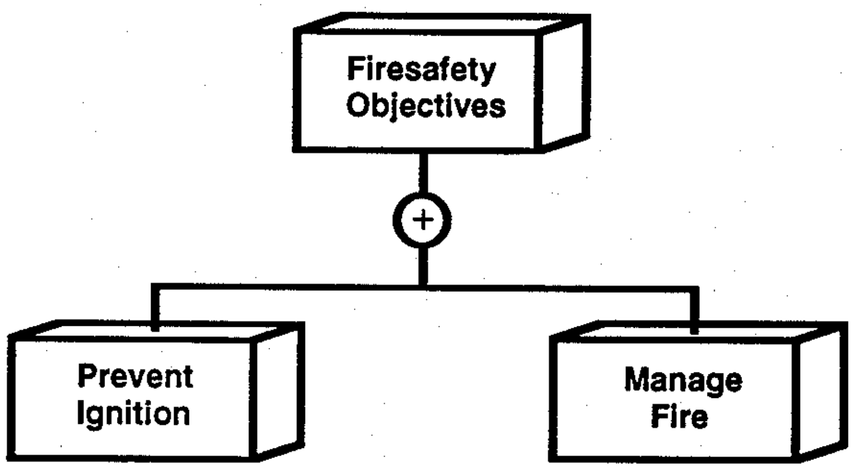

Figure 3-1

Top Branch of Firesafety Concept Tree

In theory, either event will independently lead to success, e.g. the branches are joined by an "OR" gate, denoted by the symbol ⊕; however, experience both offshore and onshore has demonstrated that the principles of both fire prevention and fire control must be applied jointly to provide sufficient redundancy for realizing success.

3.2 *PREVENTION OF IGNITION*

Total elimination of all potential sources of ignition on an offshore production platform under all operating conditions is unfeasible, as is elimination of potential sources of fuel. If this were not true, then the management of fire risks offshore would be greatly simplified. Prevention of ignition offshore is generally managed by 1) *design* -- minimizing the number of potential ignition sources, grouping and separating areas of potential ignition sources and potential fuel sources, providing systems to detect leaks, remove vapors, and de-energize/shut down ignition sources should a leak occur, etc., 2) *operations* -- instigating safe operating practices and procedures to ensure proper human response under both normal and emergency conditions, and 3) *maintenance/revamps* -- compliance with safe maintenance practices and procedures, e.g. hot-work permits, etc.

A review of the MMS events database shows that a significant number of production platform fires are caused by human activities, e.g. hot work.[2] Whenever welding or hot-cutting (torching) work is occurring on an operating production platform, there is an increased risk of ignition and fire. The degree of risk is affected by several factors, including the state of the platform, the location of the hot work in relation to fuel sources, the training, awareness, and supervision of the involved personnel, the complexity of the task, scheduling/completion demands (time/criticality pressures), and the number of independent but simultaneously occurring maintenance operations in progress.

Older platforms may be especially at risk, not only due to design inadequacies, worn equipment , inoperative fire protection systems, poor interim welding practices, higher frequency of fatigue failures in piping systems, etc., but also due to the persistence of ongoing repairs and modifications requiring hot-work operations.[3]

Another fundamental difficulty in managing prevention of ignition offshore stems from the inability to provide sufficient separation/isolation of potential fuel and ignition sources under all release scenarios likely to be encountered during the platform's operating life. Open type "warm-water" platforms such as those in the Gulf of Mexico tend to have lower loss rates than their highly compartmentalized North Sea counterparts.[4]

As recognized by the Marine Board, this suggests that enclosing or modularizing platform areas may contribute more to increasing than decreasing fire risk, by decreasing the percent of freely ventilated areas onboard. Enclosed modules are also more subject to the destructive affects of explosion blast waves due to confinement. Even in U.S. waters, however, one of the most frequent causes of operational fires and explosions on OCS platforms is entrapment of natural gas in enclosed spaces, especially during drilling operations.[5] This points to the vital importance of good ventilation practices -- both in system design and system maintenance, whether natural or mechanical -- throughout the platform. FLAIM further addresses issues of air handling/ventilation for vapor removal, ignition prevention (pressurization of electrically unclassified areas, e.g., control rooms and motor control centers), and smoke control in the section dealing with risk reduction measures.

Conversely, however, open deck designs containing both hydrocarbon handling areas and adjacent utility areas containing potential ignition sources may be more difficult to protect from large release scenarios involving volatile fuels than modularized designs. A large release occurring within an enclosed module may be better managed, confined, and controlled with a corresponding decrease in ignition risk, than one occurring on an open type platform, depending on the size of release and the wind strength/direction at the time of the event. Statistics from GOM OCS operations indicate that the third most common cause of fatalities is the opening of pressurized systems and equipment for maintenance without proper precautions[6] causing unanticipated LOC events, e.g., Arco South Pass Block 60 Platform Baker [see Appendix D]. Additionally, about one-third of all fires have involved internal combustion engines, and nearly half of these result from ingestion of released flammable vapors by diesel engines, e.g., runaways.[7] FLAIM's logic has been developed based on such information. Issues of ignition and fuel release are further addressed in Chapter 6, Layout and Configuration Assessment (LACA).

Based on past experience, it may be generally assumed that, given a large enough fuel release, an ignition source sooner or later will be encountered, or, as in the case of Chevron's Eugene Island Block 361 blowout in October, 1982 which flowed for nearly two days before igniting, the fuel release will "self-ignite" from a static discharge or frictional sparks, resulting in an explosion and/or fire.[8]

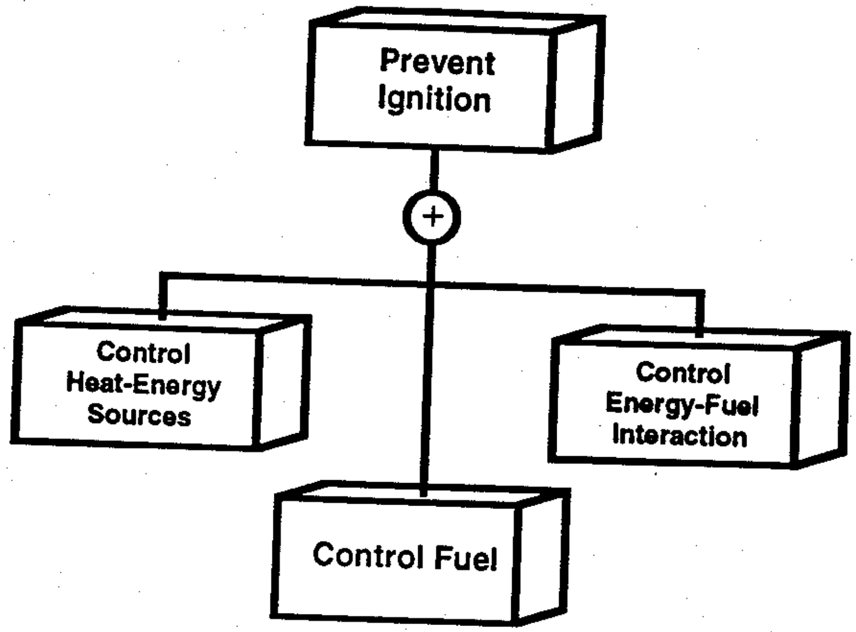

Figure 3-2

Prevention of Ignition Gate

3.3 *MANAGEMENT OF FIRE*

In the NPFA event tree the effect or impact of fire can be managed in one of two ways, and is subdivided into two branches of the event tree joined by an "OR" gate: Manage Fire and Manage Exposed (the primary life safety goal). Fire Management, in turn is accomplished either by containing/confining the fire through the use of fire resistive construction and smoke control systems, by managing the combustion process or by suppressing the fire -- either manually or automatically, as illustrated in **Figure 3-3**.

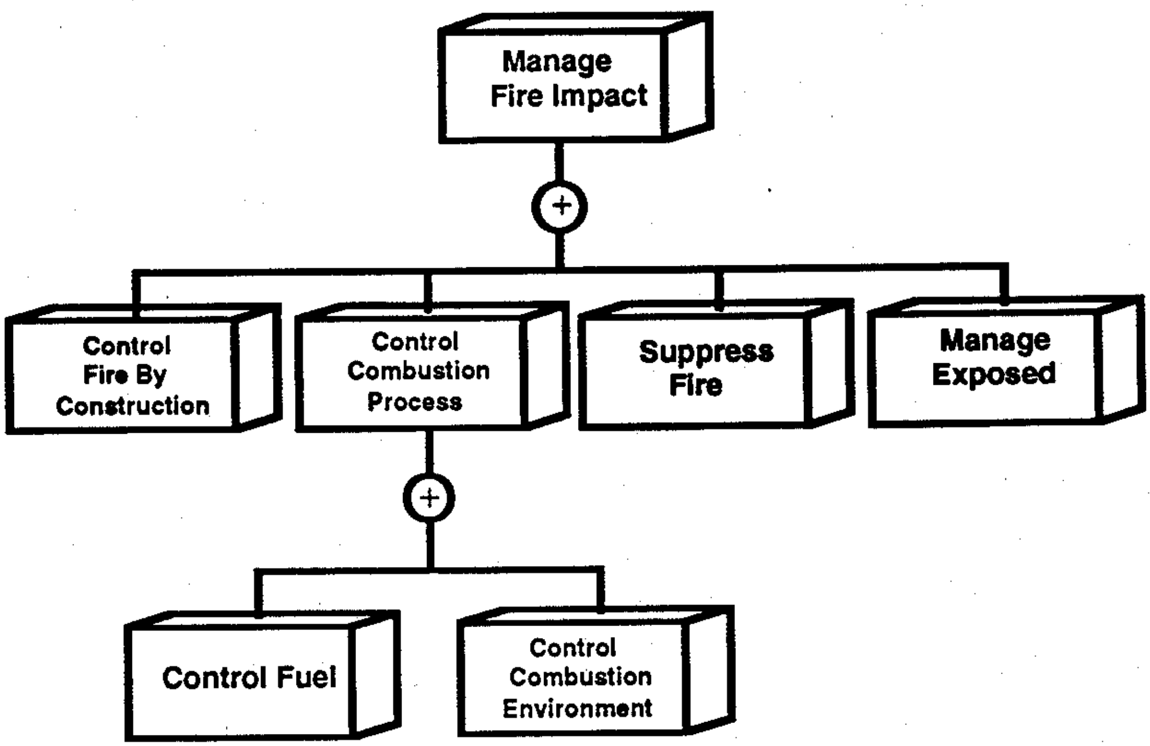

Figure 3-3

Management of Fire

Controlling a fire -- controlling fire size, growth/spread (propagation), is accomplished through a combination of controlling the combustion process via fuel and environment management, controlling the physical movement of fire via construction features, and actively suppressing the fire. In practice, various combinations of these measures are instigated offshore, depending on both design constraints and perceived risks. However, FLAIM recognizes that control of fuel -- the release rate, duration, total quantity (inventory) within a system subject to release, and its subsequent removal after release -- is essential for success. These considerations are addressed in **Chapter 4,** *Loss of Containment (LOC) Assessment.*

Control of combustion environment is, in general, impractical offshore with few exceptions, such as small enclosures/modules that can be inerted or provided with gaseous fire suppression/inerting systems. Assessment of fuel control (including prevention) capability includes many considerations such as fuel inventory, placement of system safety shutdown valves (SSVs), etc. as well as identification of LOC-prone situations. These are addressed in the next chapters dealing with loss of containment and vulnerability to escalation.

3.4 *MANAGING THE EXPOSED*

Managing the exposed addresses the means to either limit what is subject to exposure in the event of fire (personnel, equipment, structures, etc.), or safeguarding the exposed either by relocation or by defending in place, such as may be appropriate for personnel on North Sea platforms where Temporary Safe Refuges are now being required. Exposure management also addresses facility protection and includes preserving structural integrity, e.g., providing fire resistant construction such as fireproofing of structural steel supports, fire walls, etc. This overlaps with some aspects of managing fire spread.

Recognition of the importance of managing exposures has taken on new significance since the Piper Alpha tragedy. Historically, most GOM platforms were designed with little or no structural steel fire protection. In 1981, noting that most OCS accidents in which platforms are damaged or lost involve blowouts, fires, and explosions, the Marine Board concluded that prevention, rather than resistant-designed structures, was the most probable remedy for such accidents. However, FLAIM recognizes that while prevention is and should be the primary goal of the safety management system, accidents will continue to occur and accordingly must be planned for (e.g., made thermally robust) in the basic design of the platform.

The degree of thermal robustness provided in a platform's design is recognized by FLAIM to be vitally important to managing fire impact and preserving life safety. In addition, the importance of providing some degree of blast resistance to fire resistant assemblies and non-rated bulkheads has come under greater scrutiny in the post-Piper period. Not only should fire separations be designed with an inherent degree of fire resistance for exposure to hydrocarbon-fueled fires, but in addition, they must have sufficient strength and ductility (together with the means used to achieve fire resistance, such as cementitious coatings) in order to remain serviceable after high impact dynamic loading from blast waves. For this reason, FLAIM suggests that unfireproofed steel bulkheads protected by fixed water spray systems offer a lower degree of reliability as passive fire separations.

Crew members assigned to fire-fighting duties cannot hope to successfully manage developing fire events unless they are provided with sufficient time to effect control measures. Unprotected structural steel members exposed to topside fire events can fail in as little ten minutes, causing further damage and fuel release. FLAIM seeks to assess a platform's vulnerability to escalating/cascading type events and consequently, ability to manage the exposed, by examining risk factors related to susceptibility to fire damage.

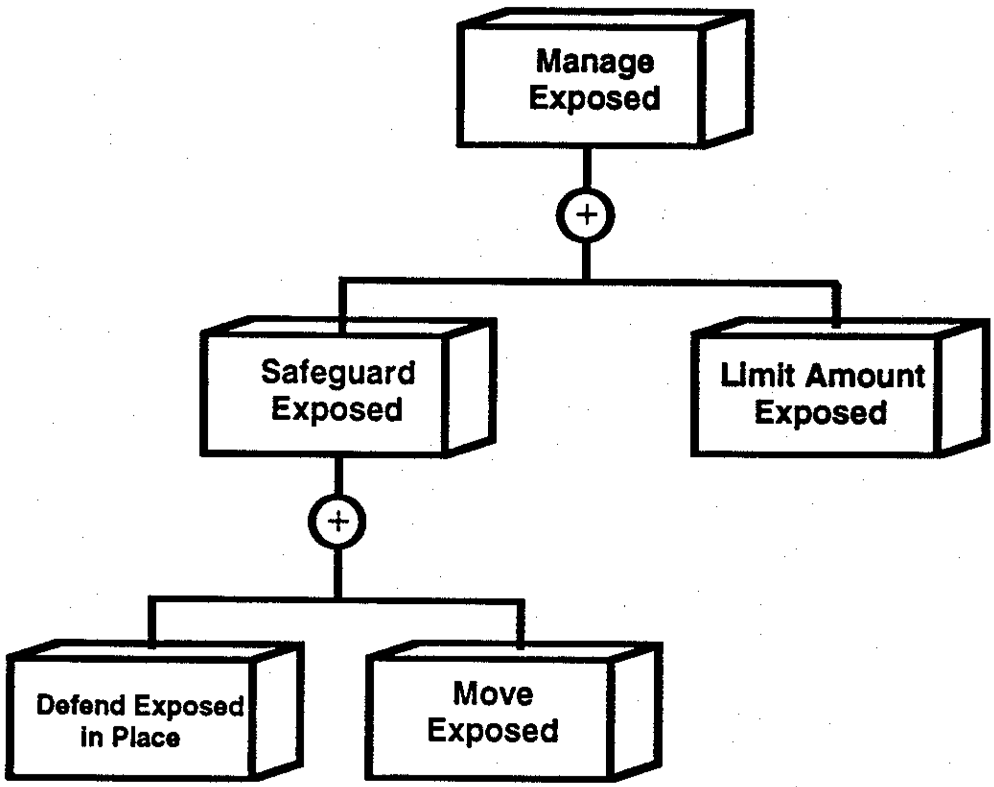

Figure 3-4

Management of Exposures

Flowing from the firesafety concept tree's "Safeguard Exposed" logic path (**Figure 3-4**) is a fundamental but vitally important life safety design concept that some existing production platforms may not fully embrace. Offshore personnel can only be "defended-in-place" for a relatively short period of time, and must ultimately rely on platform escape provisions in the event of a cascading event of major proportions. Most GOM platforms do not have TSR's, and rely on removal of onboard personnel as not only the last, but the only resort for managing the exposed, should fire control be unsuccessful. Therefore the decision tree calls for three conditions to be met: 1) a means to cause movement of the exposed, 2) a means to allow movement of the exposed, and 3) a safe destination.

In the case of Piper Alpha, safeguarding the exposed was unsuccessful, and 167 people died. The Cullen report lists many contributing factors; however, they can be summed up by saying that the means to cause movement of the exposed failed and the means to allow movement of the exposed also failed.

Most offshore platforms rely on escape capsules or life-saving crafts for the means of escape, e.g., provide a safe destination, yet may fail to provide a sufficient number of primary escape routes, exposure protection along escape routes and their access ways, or protected places of embarkation. Concern for this weakness is heightened by realizing that placing reliance on fire management through manual fire suppression efforts **always increases -- never decreases** the need for better personnel escape provisions, e.g., fire fighting provisions cannot compensate for deficiencies in protecting the means of egress. This is because personnel who are expected to respond to developing fire scenarios, instead of immediately evacuating the platform, will lose the benefit of escaping in the early stages of a fire. If their control efforts are unsuccessful, then those personnel may be forced to make their exit under extreme fire exposure conditions. While this may seem self-evident, it is not uncommon to encounter perceptions of safety based on manual fire response with less than meaningful regard for exposure safeguards -- both for personnel and for the structure.

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[1] National Fire Protection Association, NFPA No. 550, *Guide to Firesafety Concepts Tree*; National Fire Codes, Quincy, MA, 1986

[2] Visser, R.C., *Introductory Study to Develop the Methodology for Safety Assessments of Offshore Production Facilities*, prepared for MMS by Belmar Engineering, Redondo Beach, CA, August, 1992

[3] *Alternatives for Inspecting Outer Continental Shelf Operations*, Committee on Alternatives for Inspection of Outer Continental Shelf Operations, Marine Board, Commission of Engineering and Technical Systems, National Research Council, National Academy Press, Washington, D.C., 1990, p. 14

[4] Bill, F., and Goldschmidt, L., *Safety Through Separation and Simplicity* , Fire Safety Engineering, Proceedings of the Second International Conference on Fire Engineering and Loss Prevention in Offshore Petrochemical and Other Hazardous Applications, Gulf Publishing Co., 1989, Chapter 7, p.78

[5] Committee on Assessment of Safety of OCS Activities, *Safety and Offshore Oil*, Marine Board, National Research Council, 1981, pp. 158-160

6 Alternatives for Inspecting Outer Continental Shelf Operations, op. cit., p. 32

7 U.S. Federal Register, Vol. 51. No. 52, Tuesday, March 18, 1986, P. 9332

8 refer to USGS Open File Report 83-119 listed in Appendix E; One notable exception worth mentioning was the infamous 1969 Union Oil Platform "A" blowout in Santa Barbara Channel which bridged-over and ceased flowing without ever igniting, even though vapors at the cellar deck level were measured above the lower flammable limit (LFL) [based on oral communication w/ Mr. William Giesert, Union Oil Company, retired safety engineer, in a presentation at the API Committee on Safety and Fire Protection, circa 1972]. Nevertheless, managing the potential size of the loss of containment event is vitally important both from an ignition prevention standpoint as well as in managing fire impact.

<u>**Chapter 4**</u>

LOSS OF CONTAINMENT ASSESSMENT (LOCA)

4.1 *MANAGING LOSS OF CONTAINMENT*

Note that a common element to both primary branches of the concept tree, e.g., both in preventing ignition and managing fire impact, is control of fuel.

Figure 4-1

Importance of Fuel Control

Unwanted leaks, spills and other types of releases of flammable production fluids, e.g., crude oil, condensate (natural gas liquids or NGL), natural gas, and to a lesser extent, ethylene glycol, diesel, aviation fuels, and other onboard liquid hydrocarbons, are the primary cause of major fires and explosions on offshore production platforms. Collectively referred to as loss-of-containment (LOC) events, such incidents are the generally attributable to one of three fundamental causes:

- **equipment-material/mechanical failure**
- **human error -- both in design, operations, and maintenance**
- **external events (e.g., Hurricanes Andrew, (1982) Camille (1969) , etc.)**

Bea and Moore[1] have found that the source of a majority of high-consequence offshore platform accidents (generally more than eighty percent) can be attributed to compounded human and organizational errors. During the 1970's OCS records show that about one half to two thirds of all fires and explosions were attributed to equipment or mechanical failure, and the remainder to human factors -- principally errors of judgment.[2]

Equipment and material failures, however, are, in turn, most often rooted in human and organizational errors -- failure of the safety management system to either ensure the right material and equipment was initially installed for the service demands, or to properly inspect, maintain, and test production equipment and systems.

FLAIM is based on the premise that the most LOC events of significant consequence are not due to poor design, but rather stems from some form of human error,[3] e.g., personnel performing routine and/or non-routine tasks on pressurized hydrocarbon containing piping and equipment. As already mentioned in Chapter Two, the CAI found the act of opening a pressurized system for maintenance to be the third leading cause of fatalities in the GOM for the years of 1982-1986.[4] Human factors related to operational aspects of oil and gas production are evaluated in two separate sections of the assessment procedure developed for FLAIM. Chapter 10 and Appendix B7 address Safety Management System (SAMSA) risk factors involving organizational and implementation aspects of human error; "front-line" operational aspects of human error are treated in Chapter 7, complemented by Appendix B4 which has a complete listing of (OHFA) risk factors.

If hydrocarbon liquids and gases are kept confined within risers, wellheads, production separators, flowlines, pumps, compressors, fired heaters, storage tanks, etc., e.g., process equipment and piping, then the risk of fire and explosion offshore, and the resultant threat to life safety would be drastically reduced to that comparable to onshore industrial occupancies of noncombustible construction.

Unlike land-based petroleum refineries and petro-chemical plants that contain high pressure/temperature processing units subject to exothermic (runaway) reactions, oxygen entrainment (detonations), boiling liquid expanding vapor explosions (BLEVEs), etc., offshore platforms are based on relatively simple and comparatively low risk process design requirements. Physical separation of the production fluids (phase separation and emulsion breaking) and gas treatment for condensate removal and dehydration prior to compression are the main functions of onboard processing equipment.

However, flow rates and pressures offshore in some cases may equal or exceed that of a large land-based refinery process unit. Additionally, and more importantly, offshore processing facilities are subject to higher levels of physical "linkage" or "couplings" than their land-based counterparts due to layout and configuration design constraints. This in turn creates vulnerability to common-cause failures for lack of physical separation or adequate decoupling.[5] Often these couplings are critically important to both fire and life safety issues, but are frequently masked by the complexity/compaction factors endemic to topsides design constraints and practices.

FLAIM seeks to evaluate the relative risk of LOC events on any given production platform by examining key risk contributors, some widely recognized and others oftentimes overlooked, that impact fire management. FLAIM accounts for both the likelihood of an LOC event occurring, as well as the expected magnitude of the fuel release e.g. the initial fire risk should ignition occur. However, FLAIM goes beyond this to measure the potential vulnerability of platform facilities and assess the platform's susceptibility to the initiating event, seeking to identify the risk of fire growth from subsequent LOC events, failure to managed the exposed, and failure to confine/control the fire area.

A frequently encountered problem in "the field," is a failure by operating personnel and supervisors to appreciate in all cases the relative high degree of risk associated with certain common and seemingly unimportant process system components that are used in daily operations. Tomfohrde[6] makes a strong argument for the need to recognize and increase awareness of the many commonly encountered "booby-traps" in process systems, e.g., equipment drains and vents, small piping systems and connections, etc., that can lead to an initial release of fuel. As Arnold[7] points out, the design of both open and closed drain systems has been shown to be a recurrent problem on GOM platforms. FLAIM's development includes an assessment of many of these more common but often overlooked risk contributors.

Generalized causes of LOC events in industry have been identified by the Center for Chemical Process Safety (CCPS).[8] Over sixty common causes are enumerated resulting from the three fundamental categories listed above. They can be generalized into four categories:

- *open-ended routes to the atmosphere, e.g., open drain or vent valve*
- *imperfections in or deterioration of equipment integrity*
- *external impact (this would include seismic events)*
- *deviations from design conditions*

As discussed below, based on a review of case histories and historical databases, discussions with industry experts, and analysis of actual and predictive accident scenarios, FLAIM incorporates those factors deemed to be the most significant risk contributors leading to LOC events offshore, as listed in Appendix B.1 and B.2 [see Appendix F for a complete listing of LOC risk factors considered in the development of FLAIM]. It is the intent of FLAIM that the user select those factors of most relevance to the particular platform under consideration as may be judged by operator's own experience, risk preferences, and as may be determined appropriate based on available proprietary databases.

Should an LOC event occur, the magnitude of the release is a determining factor in the resultant risk to fire and life safety. Most equipment and piping leaks that occur are small, resulting from such common problems as worn packing glands and seals or from pin-hole size leaks from corrosion/erosion pitting and thinning, e.g., "leak-before-break" LOC events. Failures also occur by cracking or corrosion, or a combination of both; however, the majority of failures occur in a ductile or otherwise gradual manner, leading to small leaks and thereby providing operators with time to take corrective actions.[9]

Process equipment and piping design requirements are specifically written to ensure sufficient ductility for the anticipated operating services to avoid material failures of a brittle nature, e.g., catastrophic failure and sudden release scenarios. Such failures are exceedingly rare, but also can be very destructive.[10] However, such low probability-high consequence releases may still occur in situations, for example, where weld quality assurance and proper post-weld heat treatment requirements have been overlooked during field modifications -- resulting in crack-susceptible heat affected zones (HAZ) in critical welded joints of pressure vessels, risers, and piping.[11]

Process upsets due to malfunctioning level controllers can result in high pressure gas blow-by, possibly exposing downstream equipment to pressures above their rated working pressure. The design of the pressure relief system may not have contemplated this scenario and be seriously undersized. As Arnold[12] notes, relief valve sizing, piping pressure ratings and gas disposal system design are not generally covered by API RP 14C, Analysis , Design Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms.

Low probability - high consequence LOC events require detailed Piping and Instrument Diagram (P&ID) reviews and Hazard and Operability Studies to be analyzed in a meaningful manner, and even then may be subject to great debate. As a preliminary hazard analysis and risk assessment tool, FLAIM seeks to alert platform operators to conditions indicating further detailed studies may be warranted, based on key questions asked about platform design features and quality assurance procedures. However, in general, it is believed that relatively few fires, explosions, and injuries can be prevented through greater attention to design details. According to Arnold,[13] most GOM events appear to stem from a lack of proper attitude toward safety.

High probability - low consequence, leaks-before-break events are not uncommon during normal operations; however, to the aware operator, such events should serve as a barometer to indicate more fundamental problems in operating practices, preventative maintenance, or design deficiencies. Their frequency of occurrence is also indicative that an LOC event of greater consequence may be anticipated in the near future.

4.1.1 LOC Event Type and Magnitude -- The Source Term

The nature and magnitude of the release is characterized by consequence analysis modelers as the *source term*, and accounts for the thermodynamic state of the release fluid and the conditions associated with the event. The release may be single phase (all liquid or gas), or two phase (liquid and gas) at the point of release, and may change phases after release, e.g., condense to form liquid droplets or flash to vapor, depending on the equations of state. There are several variables influencing the magnitude of the release (mass flow rate).

For leaks in pressurized process equipment and piping, the size of the orifice (hole) through which fluid is escaping is the primary variable, since the release rate, Q, is proportional to the square of the diameter, ϕ^2:

$$Q \propto \phi^2 \tag{1}$$

This is true regardless of the phase of the fluid. For all vapor or gas releases, the release rate is directly proportional to pressure, whereas for liquid and two phase flow, the release rate is proportional to the square root of the pressure. Hence, while important, pressure does not have as great an influence on the release rate as does hole size.[14]

One study performed by the Dutch[15] proposed a quantified relationship based on data from Gulf Oil Company between LOC risk pipe length/diameter (L/D) ratio. Simply said, the Dutch study considered that larger size pipes would incur larger size (area) leaks, and that the annual risk of leakage as solely a function of the length of the line, independent of all other variables such as pressure, flow rate, etc. For source term modeling, the credible size leaks, based on qualitative rankings of small, big, catastrophic, and full rupture, can be calculated based on the size pipe in which the leak occurs as shown in **Table 4-1** below:

Table 4-1

Leak area v. pipe diameter for various leak categories

Pipe O.D.†	Small Leak	Medium Leak	Big Leak	Catastrophic Leak	Full Rupture
Diameter(in.)	*Area (sq. in.)*	*Area (sq. in.)*	*Area (sq. in.)*	*Area (sq. in.)*	*Area (sq. in.)*
1	0.00719	0.02157	0.03595	0.1438	0.719
1.5	0.01767	0.05301	0.08835	0.3534	1.767
2	0.0336	0.1008	0.168	0.672	3.36
2.50	0.0479	0.1437	0.2395	0.958	4.79
3	0.0739	0.2217	0.3695	1.478	7.39
4	0.1273	0.3819	0.6365	2.546	12.73
6	0.2889	0.8667	1.4445	5.778	28.89
8	0.5	1.5	2.5	10	50
10	0.789	2.367	3.945	15.78	78.9
12	1.131	3.393	5.655	22.62	113.1
16	1.7672	5.3016	8.836	35.344	176.72
24	4.0207	12.0621	20.1035	80.414	402.07

† **Based on schedule 40 pipe except for under 2" which is based on schedule 80**

Sources of data: *Risk Analysis of Six Potentially Hazardous Industrial Objects in the Rijnmond Area, A Pilot Study*

From the above table, and knowing flow conditions, it is possible to calculate the mass flow rate of fluid escaping for various size leaks for performing consequence analysis modeling.

The magnitude of an LOC event depends of course not only on release rate, but also on its duration. Instantaneous releases, such as the sudden failure of a flammable liquid storage tank, are extremely short duration events that can result in very large releases. Such failures, however, are generally deemed to be low probability -- high consequence events, the magnitude of which depends on the amount of material in inventory.

Following the tragic Bhopal, India[16] tragedy in December, 1984 in which more than 2500 people died, many loss prevention consultants have increasingly called for inherently safer plants through reduction of on-site inventories of hazardous materials. To use Kletz's[17] words, *what you don't have, can't leak.*

It is of interest to note that Visser[18] found that, like gas compressors, production platforms with topside flammable liquid storage tanks have about a 4% annual fire loss risk. Some platforms may realize a significant reductions in fire risk through merely reducing unneeded topside inventories of flammable liquids or finding alternative storage approaches.[19]

LOC events involving even relatively small holes (see **Table 4-1**) in process equipment and piping that is operating at high pressure can pose great risk to both fire and life safety. If ignited, resulting high momentum impinging jet fire scenarios impose among the highest thermal loads a topside structure may experience, and can rapidly lead to further deterioration and fire spread.[20]

Control of pressurized-fueled fires is best handled by rapidly isolating the supply of fuel to the fire insofar as possible and depressuring the fuel source via the platform blowdown system to flare, while cooling exposures with water spray. In general, pressurized gas-fueled fires should not be extinguished until such time that the flow of fuel can be stopped for fear of an ensuing vapor-cloud explosion. In this regard, the number, placement, and control of emergency shutdown (ESD) valves is vitally important. As Fraser[21] points out, this not only applies to surface safety valves (SSV's), but Subsurface Safety Valves (SSSV's) as well -- a subject receiving much attention in the post-Piper Alpha period.

Should the LOC event involve a flammable liquid spill or pressure release, or a two phase release scenario, the fire will most likely include a burning pool of flammable liquid. The size (surface area) of the liquid spill, and resultant fire, will again depend on the fuel mass flow rate as well as geometry of the platform. In this regards, platform design features such as curbing, deck drains, and overflow system (effluent treating system) are vitally important. The drain system must be sized to rapidly drain both spilled liquids and applied liquids (firewater) from deck areas lest the spill size be exacerbated by burning oil floating on undrained firewater.

Personnel escape ways obviously must be kept free from burning liquids, yet often times this requirement is overlooked in the design process. Process equipment should be designed to prevent burning liquids from accumulating below them, thereby preventing increased internal pressures as well as weakening supporting steel saddles. Pressurized equipment and piping exposed to fire in which only gas or vapors are handled will rapidly fail under thermal impact,[22] thereby further escalating the fire.

FLAIM has sought to account for both the conditions that lead up to the most frequently occurring damage-causing LOC events, and the conditions that contribute to them, as well as to prevent further escalation by assessing key vulnerability risk factors and risk reduction measures.

4.2 *LOC RISK CONTRIBUTORS*

FLAIM's primary focus is directed towards assessing the life safety and fire safety risks on existing production platforms, many of which are 15 to 20 years old or more and are in various stages of deterioration. FLAIM is not specifically intended for the evaluation of newly designed platforms, although it may be so utilized, based on the premise that in the post-Piper Alpha period, all new platforms will be subject to a detailed hazard identification and risk assessment review in accordance with API RP-75, e.g., a Hazard and Operability Study or equivalent. Further, as described below, FLAIM is based on the assumption that newly designed topside systems and equipment have been scrutinized for compliance with the relevant standards and recommended practices and associated quality control procedures such as ISO 9000.

4.2.1 Mechanical/Material Considerations

FLAIM's development necessitated a comprehensive review of possible initiating contributors to LOC events in order to identify what are believed to be those factors of most significance contributing to the risk of containment loss (see Appendix F).

Mechanical integrity of process systems and components is an obvious requirement to prevent unwanted releases of hydrocarbon fluids. FLAIM is based on the premise that hydrocarbon containing equipment on new platforms has been designed, fabricated, inspected, tested, and installed to the requirements of the appropriate standards and recommended practices for pressure vessels, piping, and piping components (valves, fittings, etc.) as specified by ASME, ANSI, API, ASTM, NACE, etc. in compliance with the Outer Continental Shelf (OCS) Orders[23] of the U.S. Mineral Management Service. Further, on existing platforms, FLAIM recognizes that a history of satisfactory operating experience as *á priori* indication that the risk of break-in-period failures, due to inherent fabrication flaws/defects, can be largely, but not totally discounted.

Perfect pressure vessels and piping materials do not exist, nor do perfect fabrication and inspection techniques. Many apparent defects may not reduce service life; conversely, small and undetectable flaws in the base material or in a heat affected zone (HAZ) can ultimately lead to catastrophic failure, especially if subject to high operating temperatures, high stress levels, and hydrogen saturation. As Naumann[24] observes, "cracks (in the base metal) are separations that have not yet led to failures, but often are the incipient cause."

In the U.S.A., catastrophic process equipment failures (sudden ruptures) due to inherent fabrication defects are exceedingly rare largely due to prescribed quality assurance requirements and strict code provisions governing fabrication and testing, such as those specified by ASME, API, ASTM, etc.[25] FLAIM considers fabrication flaws as an inherent residual risk that cannot (and should not) be meaningfully accounted for in a Tier 1 screening process, with the caveat that compliance with modern quality assurance standards and fabrication/inspection practices is assured and verifiable.

FLAIM does ask, however, about modifications to the process system during its service life, with emphasis on weld quality, service ratings, and material suitability. For example, FLAIM asks if all "as-built" materials-of-construction used to fabricate process components for production system modifications can be accounted for (are known, documented,, and verifiable) and further, that the service ratings of these components meets or exceeds those required for the actual service demands that the system is operating under. Consequently, if these questions cannot be readily answered, a detailed material audit may be warranted together with a verification of the "As-Built" equipment drawings given the operating conditions and service history.

In typical US-OCS platform production systems different pressure ratings zones or "spec-breaks" may be found according to the location of pressure reducing valves (PRVs), choke valves, and provision of pressure safety valves (PSV's).[26] All process components within a given spec-break must be rated to meet or exceed the maximum working pressure within that pressure zone. Wellheads are normally subject to ("see") the highest pressure of all components in the topside production system, and must be designed to meet this service (see §5.2.2.8).

The wellhead wing coke is typically the first place where system pressure is decreased, although downstream flowlines and production/test manifolds are often rated for the same service pressure as the wellhead,[27, 28] The first stage (high pressure) separator, however, may be designed (rated) for a considerably lower pressure rating than that of the wellhead. Correspondingly, the second and third stage separators, which operate at further reduced pressures, may be designed with lower operating pressure-rated piping and components.

FLAIM asks that the production system be reviewed to ensure that 1) all equipment items and piping components within any given pressure zone meet or exceed the minimum pressure rating required for section of the system, and in addition, that 2) every pressure zone that is rated below wellhead pressure be equipped with suitable pressure relieving devices as called for by API RP-14C[29] (unless all piping and equipment within that section of the process is designed for full wellhead pressure). This is to ensure that, for example, flanges rated for ANSI Class 150 or 300 service have not be inadvertently installed where Class 600 (or higher) flanges are needed, based on the set pressure of the relief valves.

Note that in a conventional risk assessment, using more formalized assessment techniques, a what-if type analysis would typically be required, e.g., Hazard and Operability Study, to test what (failure mechanisms) could cause excessive pressure within any section or zone of the production system (such as the failure of a choke valve). This allows a systematic review of the system to determine if all pressure relief valves are properly sized and set at the proper relieving pressure to protect system components, and if the piping and equipment pressure rating for that section of the process is adequate. FLAIM does not go to this level of detail, inherently assuming that good engineering practices have been followed in the initial design and construction of the platform topside systems. FLAIM does, however, ask if compliance with API RP-14C is verifiable and if a recent assessment has ever been made. FLAIM includes provisions for this uncertainty based on the historical operating experience in the event that no detailed formal safety reviews have explored such questions.

FLAIM also seeks to identify any piping components that may have been installed during the platform's operation life that are particularly susceptible to failure under fire exposure conditions, e.g., flangless wafer-type valves, pipe clamps and couplings, expansion bellows, etc. This is addressed in the section dealing with vulnerability to escalation.

4.2.2 Material/Equipment Deterioration Considerations

Of great concern are service failures leading to LOC events due to deterioration of a material/mechanical nature. Essentially all hydrocarbon containing equipment on an offshore production platform deteriorates, at various rates, as a result of its service demands. FLAIM has identified those conditions most often leading to equipment failure and an LOC event as follows:

1) Chemical Degradation (corrosion)

- internal (from produced fluids)
- crack-inducing mechanism
- external (environmentally induced)

2) Erosion (abrasion), and

3) Fatigue Cracking

Each of these areas are addressed below in § 4.3.

4.3 *LOC CORROSION RISK FACTORS*

4.3.1 Internal Corrosion and Cracking

Corrosion of materials/equipment and piping employed in oil and gas production, both onshore and offshore, is a primary cause of deterioration and service failures. FLAIM accounts for the risk of an LOC event from corrosion by assessing 1) exposure to corrosion -- the relative corrosiveness of the production stream, recognizing that this can change with time, 2) the susceptibility of the platform's process components to corrosion, e.g., material suitability for the present production conditions, and 3) the platform's corrosion detection, monitoring and control program as presently being formulated by management and implemented by operating personnel.

Crude oil, gas, and produced water, e.g., the well stream, contains a host of corrodents deleterious to production equipment internals and interconnecting piping, including: organic and inorganic salts (chlorides, bicarbonates, bromides, sulfates, etc.); mercaptans and organic sulfur compounds (most notably hydrogen sulfide); a variety of organic acids naphthenic, acetic, stearic, etc.; carbon dioxide and carbolic acid; dissolved oxygen, and of course brackish-water which also in turn contains many dissolved salts and minerals.[30] In addition external corrosion due to the saline environment is a major problem for platform operators, both with regard to structural serviceability and process equipment and piping integrity.

In the production system, corrosion can and does occur everywhere to some extent, both downhole and topsides, internally and externally. Essentially all internal corrosion reactions occur due to the presence of water in the production steam. Dissolved gases, such as oxygen, hydrogen sulfide, and carbon dioxide are the primary driving force behind high rates of material loss, thinning, pitting, etc. as well as associated cracking problems such as sulfide stress cracking, chloride stress cracking, hydrogen embrittlement, and associated stress cracking phenomena.

With regards to topsides production systems, internal corrosion can be a problem from the most upstream equipment item, the wellhead, to the most downstream point at which the treated production products leave the platform. High pressure gas wells, especially "sour wells," as described below, may cause severe corrosion problems in wellhead wing valves and pressure reducing chokes.[31] Erosion, addressed in a subsequent subsection below, can also be a primary cause of rapid deterioration and early failure of flowlines, pressure let-down (control) valves, e.g., "chokes, " and piping components such as Elbows and Tees.

Most oil and gas separators (including slug-catchers) do not, in general suffer from significant metal loss corrosion,[32] but rather are subject to buildup of scale and sediment leading to decreased efficiency. However, gas dehydrating and treating facilities, and crude oil treaters (heater-treaters) are susceptible to corrosion and associated service failures leading to loss of containment events. Platforms with crude oil storage tanks may also experience severe corrosion problems therein, including external corrosion (increased by their typical location in the lower levels of the deck structure).

Dissolved oxygen in the production stream is perhaps the greatest offender of all corrodents, and can lead to high rates of metal loss and pitting even at very low concentrations (less than 1 ppm), as well as acting to accelerate the corrosivity of H_2S and CO_2. Enhanced oil recovery (EOR) techniques (secondary recovery methods) using produced water (brine) for injection (waterflooding) typically employ oxygen scavengers in order to control this problem.[33, 34]

Some tertiary EOR recovery techniques are particularly damaging to both downhole and topside production equipment, such as thermal methods employing "fireflooding," "steamflooding" technology, and gas injection methods using CO_2. Fireflooding, in which air is injected into the reservoir to sustain a *in situ* combustion reaction, causes an exceptionally severe corrosive/erosive environment due to the wide range of by-products produced.[35]

Dissolved carbon dioxide forms carbonic acid, which tends to cause internal pitting and general metal loss. This type of corrosion is sometimes referred to as *sweet* corrosion, in contrast to *sour* corrosion as caused by the presence of hydrogen sulfide. Severe pitting of gas condensate well tubing is a known sweet corrosion problem, and can lead to penetration of wall thickness in relatively short periods. Gas-lift wells in sweet service are also generally susceptible to corrosion failures, especially if even only small amounts of oxygen are present.[36]

H_2S is often present in oil and gas streams and is a major contributor to material service failures. In addition, H_2S is highly toxic and constitutes a significant risk to life safety when present even in relatively low concentrations.[37] H_2S also tends to form pyrophoric iron sulfide as a corrosion byproduct. When exposed to air during turnarounds or at other times of entry, process vessels and storage tanks containing iron sulfide and oil sludge can spontaneously ignite, causing injury to workers and possibly resulting in an explosion in the event the vessel or tank was not completely gas-free.

Severe pitting can occur in high pressure sour gas wells that are high water producers. However, some sour gas wells may exhibit very little, if any, surface pitting, but still have high service failure rates. This is frequently due to hydrogen embrittlement and/or sulfide stress cracking, as described below.

Increasing temperature and pressure generally worsen the corrosion problem. High pressure/temperature wells and EOR injection wells can be particular problems and demand specialized materials and close scrutiny to drill and operate. Flow velocity is also a major factor, and is discussed more fully under the section dealing with erosion and impingement.

Hydrogen is a reaction byproduct of iron in the presence of H_2S or CO_2 (carbonic acid), and can be absorbed into and saturate the base metal substrate to cause a variety of failures, including blistering, cracking, and embrittlement. High pressure and the presence of sulfide ions serve to catalytically accelerate the invasion of atomic hydrogen into the inter granular substrate. Also any small fabrication flaw in a vessel or pipe wall, such as an inclusion or lamination void can contribute to blistering and service failure. Hydrogen induced embrittlement is also a concern where high strength steels are used (F_y>90,000 psi).

Another related phenomenon first recognized in the early 1970's in pipelines handling sour crude is known by several acronyms, including "SOHIC" for stress-oriented hydrogen induced cracking.[38]

Sulfide Stress Cracking (SSC), also known Sulfide Corrosion Cracking, is a phenomenon of great concern that can lead to brittle failure in high strength alloy steels under high stress levels. Residual stresses, hard spots (>200 Brinell, BHN), and points of stress concentration created by welding, cold work, or poor design can also lead to localized failures of lower strength (mild) steels normally considered immune to this type of failure mechanism.

During the mid-1980's it was discovered that the extent of cracking caused in petroleum refinery LPG storage vessels from exposure to "wet" H_2S service, e.g. those process streams containing more than 50 ppm of H_2S in a separate water phase, was much more prevalent that previously known. This was because SSC initiated cracks often times go undetected using conventional inspection techniques, and can only be reliably detected using wet magnetic particle fluorescence inspection methods[39]

The full extent of SCC (and associated cracking phenomena) in offshore production processing systems and equipment is generally unknown; FLAIM addresses this by assessing the extent to which high strength steel/alloys have been employed for fabricating topside production equipment, e.g. wellheads, pressure vessels (separators), and other system components in compliance with API and NACE requirements, and the nature of the inspections routinely performed thereon.

Where SSC is a known or suspected corrosion mechanism, materials used on the platform should conform to the requirements of NACE MR-01-75, *Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment*, except as otherwise allowed by API RP-14E.[40] FLAIM asks if these requirements have been met and are verifiably for all equipment as presently installed on the platform.

Chloride Stress Cracking (CSC) is another concern in certain alloy and stainless steels, e.g., ANSI 300 series austenitic stainless, especially if oxygen is present and the production stream is above 140°F. Many offshore platforms use austenitic stainless steel where an extreme corrosion/erosion problem may exist, e.g., for pressure vessel internals, control valve trim, tubing for instrument/control, etc., but generally restrict its use to services below 140°F.[41] FLAIM asks if any failures in production system have occurred to CSC of components, and whether such failures are a continuing problem.

Because of the many variables and complex relationships that are involved in predicting corrosion susceptibility, FLAIM does not presuppose to establish specific criteria for classification of services in terms of non corrosive fields (oil and gas reservoirs) v. corrosive fields. This determination is best made by the informed metallurgist/material specialist in combination with the petroleum geologist/reservoir engineer.

Table 4-2

Factors contributing to corrosion

Corrosive Gas	Solubility PPM†	Non corrosive PPM	Corrosive PPM
Oxygen	8	<0.005	>0.025
Carbon Dioxide	1700	<600	>1200
Hydrogen Sulfide	3900	*	*

† solubility at 68°F in distilled water at one atm. partial pressure

* no limiting values shown because the amount of CO_2 and/or O_2 greatly influences the metal loss corrosion rate. H_2S alone is usually less corrosive than carbon dioxide due to the formation of insoluble iron sulfide film which tends to reduce metal weight loss corrosion.

Source: Table 1.1, Qualitative Guideline for Weight Loss Corrosion of Steel, API-RP 14E-1991, p.13

It is always good practice to perform laboratory materials tests of reservoir fluids, obtained from exploratory wells, in areas where undeveloped fields will be produced, e.g. new production platforms are being planned in previously undeveloped areas. However, for the development of existing fields, or in the case of existing platforms, it is generally recommended that available corrosion data/experience be considered in making this determination. As a general "rule of thumb," API RP 14E gives the following guidelines for metal-weight-loss corrosion factors as shown in **Table 4-2.**

FLAIM incorporates a metal loss rate to calibrate the relative risk of LOC events resulting from corrosion, in conjunction with assessing comprehensiveness and quality of a platform's in-place corrosion detection, monitoring and control program. The corrosion rates shown in **Table 4-3** have been developed as general indicators of the severity of the corrosion problem.

Table 4-3

Annual rate of metal loss v. corrosion severity

Rate of annual metal loss	Corrosion Problem
2 mils or less	negligible
between 2 to 10 mils	mild
11 to 25 mils	moderate
above 25 mils	too high -- consider material change
above 100 mils	severe problem/ high LOC risk

Additionally, FLAIM is set up to interrogate platform operators to determine if conditions in which SCC may occur have been identified, and that process component materials in wet H_2S service meet OCS/NACE requirements. Gas systems operating at pressures above 65 psia that contain H_2S at a partial pressure above 0.05 psia should be considered sour. For example, a gas stream at 1000 psia that contains 100 ppm of H_2S (0.01 mole %) would have a H_2S partial pressure of 0.1 psia, and therefore is considered sufficiently sour to promote cracking.

The definition of a "sour environment" with regard to cracking may be found in API RP-49,[42] which, in turn is based on NACE Standard MR-01075.

4.3.2 Internal Corrosion Program Assessment

A comprehensive corrosion program should contain three components: corrosion detection, corrosion monitoring, and corrosion control/mitigation. In addition, a materials identification/control program and a welding procedures and quality assurance (QA/QC) program are closely aligned; these are substantive components of any platform's overall safety management system.

FLAIM assesses the adequacy of the in-place corrosion detection, monitoring and control measures that are actually being followed on a platform and calculates corresponding values in the LOC index algorithm.

4.3.3 Corrosion Detection and Monitoring

Several means exist for detection and measuring corrosion in topsides production systems. These include corrosion probes of various types and corrosometers, corrosion coupons, corrosion spools, corrosion calipers -- both mechanical and electronic/electromagnetic types, routine ultra-sonic testing (UT), and radiography to name a few. Of all methods employed, many experts believe that visual inspection, where practicable, is the most reliable means of detecting corrosion.[43] Recognizing that as reservoirs are drawn down and fluid compositions change, so does the corrosion profile, it is deemed important in FLAIM that corrosion detection and monitoring is performed on an ongoing and continuing basis.

Corrosion trends should be established and routinely updated in accordance with the relative degree of corrosivity of the production streams and rate of material deterioration. This obviously demands that detailed records and databases be maintained for every platform, regardless of the rate at which corrosion may be currently progressing.

4.3.4 Corrosion Control

There are a number of ways to approach corrosion control, including the use of corrosion resistant materials, coatings -- both internal and external, chemical treatment, e.g., the use of corrosion inhibitors, cathodic protection using sacrificial anodes, impressed current systems, etc. For internal corrosion control, many platforms rely on the use of chemical injection systems to retard or inhibit the electrochemical corrosion process by coating the exposed metal with a protective film.

The relative degree of effectiveness of a particular chemical treatment can be tested in several ways using standard test procedures such as the NACE static test, the

Wheel test, the Flow test, etc. Treatment can be performed on a batch basis or be continuous via chemical injection.

FLAIM seeks to determine if effective corrosion control provisions are being used to prevent LOC events resulting from either internal or external corrosion. FLAIM is not intended to perform a detailed "how-to" analysis, but rather simply asks if the corrosion control provisions in-place are considered to be effective and adequate. Accurately answering these questions, however, may require considerable research, especially on older platforms which have undergone a series of modifications over the years and some materials in the production system may not be readily identifiable. As previously discussed, such an audit may be necessary to perform, together with a check of service ratings.

4.4 *EXTERNAL CORROSION*

External corrosion of topside process systems and equipment is also a significant problem, even though most equipment is installed above the so-called "splash-zone," e.g., the area of the jacket subject to wave action, where external corrosion is most severe. It is common for the exterior of process equipment to have a constant layer of highly corrosive saline coating from sea spray, wash-down with utility (brine) water, or by just being constantly exposed to highly humid conditions in the open sea.

External corrosion can also severely effect control and instrumentation systems, including surface safety valve actuators, fire and gas detection devices, and even fire protection deluge systems. For example, Exxon's Hondo platform in southern California waters and others in the GOM recently have been forced to completely replace their carbon steel fire protection distribution and open-nozzle water spray systems with "90-10" Cu-Ni alloy due to severe external and internal corrosion.[44]

External corrosion can be a particular problem beneath cementitious coatings used for protecting structural steel from fire exposure, and beneath conventional thermal insulation systems, such as calcium silicate, commonly used for energy conservation and/or personnel protection in petroleum processing facilities. Insulated piping and vessels can trap moisture and develop localized areas of corrosion that are difficult to detect, and may escape inspection.

Lazar[45] has identified three determining factors affecting the weight loss of carbon steel due to corrosion under insulation (CUI): 1) wet exposure cycle characteristics (duration and frequency), 2) corrosivity of the aqueous environment, and 3) failure of protective barriers (paint and jacketing). Additionally, seven contributing factors were analyzed to study how common practices could be improved to better control this type of corrosion. While selection of the appropriate coating plays a major role in preventing CUI, Lazar reports that improper maintenance practices, e.g., failure to preserve the intended integrity of the coating system (human error), is a leading cause of CUI.

FLAIM assesses the extent of external corrosion problems in a manner similar to that for internal corrosion -- by seeking to determine the platform's susceptibility, past history, and current mitigating practices to detect and control external corrosion via materials, coatings, and proper maintenance and inspection techniques.

4.5 *LOC EROSION RISK FACTORS*

Erosion of internal surfaces is caused by high velocity/turbulent fluid flow and solid particle (e.g., sand) impingement of interior surfaces (of piping, valves, pumps, vessels, etc.) is a common cause of loss of containment events. Fluid cavitation also falls within this category such as may be caused by large pressure drops across control valves or at the impeller of process pumps. Normally erosion is a localized failure mechanism and only occurs in certain sections of the process system where, for example, piping changes size or direction (e.g., at reducers, elbows, tees, etc.), or where there is a pressure reducing device, such as a choke or restriction orifice.

Some production wells may tend to produce copious amounts of sand/sediments, leading to high rates of erosion, whereas other wells may not, depending on local reservoir characteristics. This may also change during the course of platform operations.

Fluid erosion in flowlines, production manifolds, process headers and other lines that handle well fluids in a two phase mixture, has been related to flow velocity by the following equation:

$$Ve = \frac{c}{\sqrt{\rho_m}} \qquad (2)$$

where Ve = fluid erosional velocity, feet/second

c = an empirical constant: = 125 for non-continuous service or 100 for continuous service, and if sand is present, c < 100 based on experience

ρ_m = gas/liquid mixture density at operating pressure and temperature, lbs/ft^3

[source: American Petroleum Institute Recommended Practice RP-14E, 5th edition, Oct. 1991, p.23, eq. 2.14]

Erosion can be minimized by selecting a cross section area appropriate for the flow conditions to keep flow velocities at or below the calculated erosional velocity, e.g., acceptable values, in accordance with equation 2.10 of API RP-14E. However, API cautions that minimum flow velocities should be kept above about 10 ft./sec. to minimize slugging in the crude separators.

FLAIM asks if, on existing platforms, erosion has been found to be a problem, given that sufficient operating experience has been accumulated for meaningful responses. If erosion problems have been detected, or in the case of new process systems, FLAIM seeks to verify that line sizing has been determined in accordance with RP-14E based on actual flowing conditions.

If sand is present in produced well fluids and is a contributing factor, FLAIM asks if erosion monitoring devices, e.g., sand probes or other means of detection, have been installed in key segments of the process system where erosion is most likely anticipated. As in the case of internal and external corrosion, FLAIM's objective is to establish the risk of an LOC event due to service failures from undetected/unexpected erosion.

4.6 *PIPING VIBRATION AND FATIGUE FAILURE RISK FACTORS*

Despite the fact that piping failure from vibration and fatigue has been recognized for a long-time as a major cause of fires in the hydrocarbon processing industries, it is still not uncommon to find that many platform operators fail to recognize their potential seriousness. This is, perhaps, due to the extensiveness of the problem, often leading to complacency among operating personnel. Vibration induced cyclic bending stresses, however, can ultimately lead to metal fatigue, cracking, and, depending on the material's ductility and corrosiveness of service conditions, e.g., wet H_2S or sour gas, loss of containment.

There are two general scenarios most commonly encountered in platform operations in which fatigue failure presents a high risk: piping associated with rotating machinery -- especially reciprocating machines under heavy loads and high speed centrifugal machines; and control valves across which a high pressure drop is realized.

Small diameter piping e.g., one inch and under, that has threaded (screwed) connections and is in hydrocarbon service is a know high risk contributor. Unsupported small diameter pipes connected to heavy valves that are freely vibrating will, sooner or later, form fatigue cracks at points of stress concentration, e.g., at the root of the thread cuts, and are a common cause of LOC events.

If cyclic bending stresses in a piping system coincide with the natural vibrational frequency of the piping geometry, resonance will occur, amplifying the amplitude of the vibration and accelerating the time to fatigue failure.

Reciprocating pumps and compressors, especially large units operating at high pressures, are one group of risk contributors FLAIM seeks to examine for potential fatigue risks. These machines operate at relatively slow speeds and can generate large flow and pressure surges. Most often, resulting piping vibrations are obvious; however, some piping components may incur dangerously high cycle vibration that is not immediately observable to operating personnel. Platform operations commonly employ triplex power pumps and similar reciprocating pumps for a variety of applications in both drilling and production operations. Such pumps can experience flow and pressure fluctuations in a higher range of frequency than other pumps, and the piping associated with these machines may be subjected to severe vibration.

Another less conspicuous but common high frequency vibrational problem is encountered with centrifugal pumps and compressors. These high speed machines result in vibrational frequencies that may go undetected until piping failure occurs. This may also occur with certain control valves subject to large pressure drops and high flow rates, e.g., where there is a large dissipation of energy. However, with control valves, vibration problems may be more obvious due to associated noise emission. Therefore, where noise from fluid flow conditions is prominent, platform personnel should also suspect potential vibration problems.

Production system piping vibration problems can be classified into two groups: 1) high frequency/low amplitude vibration, and 2) low frequency/high amplitude vibration.

Machinery piping will vibrate at a fundamental frequency determined by the operational speed of the machine, or at a multiple of the fundamental frequency, e.g. a harmonic frequency. Certain types of equipment on a platform have distinct modes of generating vibrations, e.g., double acting reciprocating compressors induce second harmonic vibrations, and centrifugal compressors produce harmonics in accordance with the number of vanes on their impeller. Piping vibrating at harmonic frequencies will be the most noticeable; however, lower frequency machines, such as reciprocating compressors, can also have piping details associated with them with high natural frequencies, e.g., drain valves, etc. Refer to Section 5.2.2.6, Piping, Valves, and Piping Components and Practices for further information.

4.6.1 Vibration Monitoring and Control Program

FLAIM seeks to assess, insofar as possible, the extent of vibration and fatigue failure risk on a give platform based on operating experience. Based on a visual survey of small piping, FLAIM asks the user to estimate the extent to which small piping subject to vibration is ungussetted or otherwise not properly supported. It provides a suggested guideline to determine relative severity to assist the user in this determination. FLAIM also seeks to determine of all small piping in hydrocarbon service is socket welded or, if threaded, whether the threads have been seal-welded and if the seal completely covers all exposed threads.

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[30] see Guide *for the Inspection of Refinery Equipment*, American Petroleum Institute, Division of Refining, Second Edition, 1973, Chapter II, Conditions Causing Deterioration or Failures

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[32] As reported by NACE TPC publication No. 5, Corrosion Control in Petroleum Production, National Association of Corrosion Engineers, Houston, 1979, p. 5. However, recent inspections of pressure vessels in wet H_2S service has raised considerable concern about the extent of possible sulfide stress cracking not heretofore recognized as a significant problem. This is largely due to the use of wet florescent magnetic particle inspection techniques following the catastrophic failure of a pressure vessel in Union Oil Company's Lemont Refinery. For further information, refer to Gale, Jr., W.E., *A New Level of Safety for LPG Storage*, Applied Fire Safety Engineering Research Aspects, C.E. 299 Research Report, University of California, Berkeley, Department of Civil Engineering, May, 1988.

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[34] *CO_2 Corrosion in Oil and Gas Production, Selected papers, Abstracts, and References*, National Association of Corrosion Engineers, (compiled and edited by Task Group T-1-3, L.E. Newton and R.H. Hausler), Houston, 1984

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[37] FLAIM has been designed to ask if hydrogen sulfide is present in the production fluids in sufficient quantities to be a life safety risk. If the answer is yes, FLAIM recommends that a separate life safety study be performed; future versions of FLAIM will incorporate specific hydrogen sulfide life safety risk factors

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Note: Bob Merrick was subsequently employed by Shell Oil Co., working in the Martinez (California) Manufacturing Complex where the writer participated with him in performing Hazard and Operability Studies for various refinery units in 1990.

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[40] *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*, American Petroleum Institute Recommended Practice 14E, Fifth Edition, October 1, 1991

[41] Ibid., p. 13

[42] API Recommended *Practices for Safe Drilling of Wells Containing Hydrogen Sulfide,* American Petroleum Institute, Appendix C, Second Edition, April 15, 1987

[43] *Corrosion Control in Petroleum Production*, op. cit., p. 46

[44] Gilbert, D., and Mayhew, R., Safety Initiatives Enhance Integrity of Offshore Platform Operations, Journal of Petroleum Technology (JPT), May, 1993, pp. 478-484

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Chapter 5

VULNERABILITY TO ESCALATION ASSESSMENT (VESA)

5.0 *INTRODUCTION*

The platform's vulnerability to escalation of an initiating event into a high consequence event depends on many inter-related factors. **VESA** accounts for those basic design and operational risk contributors that most influence a platform's vulnerability or susceptibility to event escalation and loss of control, i.e., cascading fire events. Closely associated with these factors, but categorized separately for convenience, are layout and spacing risk factors in Chapter 6, *Layout & Configuration Assessment* (LACA). Consideration of risk reduction measures, such as fire and blast walls, fireproofing, explosion venting, fire suppression systems, etc. are treated separately in Chapter 9, *Risk Reduction Measures Assessment* (RIRA).

5.1 *ELEMENTS OF VESA*

VESA factors[1] are designed to assess those features or deficiencies in topside design features and the state of operations that may contribute to the inability to:

1) rapidly control, direct, and stop a LOC incident before ignition occurs,
2) prevent ignition after a release has occurred
3) control the initial fire size and its resulting thermal impact on adjacent equipment and piping, and
4) prevent a further cascading of LOC events and vulnerability to escalation

The VESA module of FLAIM assess:

- Equipment Risk Factors -- selected platform equipment and piping risk factors, including equipment type, operating pressure, installation practices, and known problem areas such as some piping design practices known to be highly susceptible to fire impact
- Special System Risk Factors -- selected platform system risk factors, including gas treating systems (glycol dehydration systems, etc.)

- Ignition Risk Factors -- potential sources of ignition (fired equipment, electrical area classification, etc.)
- Loss of Control Risk Factors -- process control and emergency shutdown systems (# of ESD's, remote SD's)
- Pressure Relief Capability -- pressure relief and depressuring (blowdown) capabilities, flare system design, vent system, liquid dump system if any
- Liquid Spill Control -- platform open and closed drain systems.
- Vapor Control Provisions -- ventilation provisions for enclosed areas
- Emergency System Power Supply -- power and control system reliability (fail safe/ups/redundant data highway/etc.
- Thermal Robustness -- structural design for thermal impact

5.2 *VESA EQUIPMENT RISK FACTORS*

5.2.1 Age and Condition of Process Equipment and Piping

Recognizing that topside process equipment and piping may have undergone numerous modifications and upgrades during the service life of older platforms, FLAIM seeks to establish the approximate age and service conditions of the oldest equipment items and piping handling production fluids. FLAIM asks the user to estimate the age and general condition of topside process system components (see Appendix B2). Older piping systems and process equipment are generally at greater risk to high cycle fatigue failures, cracking/corrosion/erosion failures,[2] and even failures caused by inadequate field repair procedures, e.g., poor welding quality assurance, etc. Additionally, older piping systems and equipment that may have less mechanical strength and ductility due to aging and service effects can be expected to fail more rapidly when subjected to high pressure/high stress/high temperature conditions caused by fire exposure.

Regular thickness inspection procedures for corrosion monitoring should include statistical sampling techniques to estimate the remaining corrosion allowance half-life in establishing inspection frequencies. Small piping and nipples in demanding and critical services should be periodically radiographed to assess their condition. FLAIM asks if corrosion trends have been established for all process components and what are the shortest remaining half-lives. Vessels and piping with half-lives of less than five years are considered to be at greater risk than those having longer half-lives. The frequency of routine and special (e.g., wet fluorescent magnetic particle) inspections that are performed on critically important hydrocarbon handling (CIHH) equipment items is also assessed.

Criticality important hydrocarbon handling (CIHH) equipment items are defined as those with high fire risk potential based on the pressure and flow-throughputs of the hydrocarbons being handled. High vapor pressure materials, such as natural gas liquids containing propane, butanes, and other light-ends are included in this category. A greater uncertainty in the reliability of older process piping components and pressure vessels that are being operated at high pressures and/or flow rates is accounted for in FLAIM, For example, FLAIM asks about the age, size, and state of knowledge about the integrity of topside flammable liquid storage tanks to arrive at a risk index that assesses both risk of failure and the magnitude of consequence.

Age and period of design and construction is also indicative of the adequacy (or deficiencies) of initial design criteria. Some platforms, for example, may still utilize cast iron piping components in hydrocarbon service, or have little or no passive fire protection. Age can also indicate endemic problems such as undersized relief systems and inadequate drains system capacity.

5.2.2 Equipment Type

Visser[3] has identified equipment type as a primary risk factor on production platforms. He found that OCS production platforms equipped with compressors, flammable liquid storage tanks, and fired heaters have significantly higher annual loss rates than those platforms not so equipped. FLAIM has identified equipment related risk factors and asks for information about certain types of equipment known to increase platform fire risk.

5.2.2.1 Rotating Equipment

Rotating equipment may pose a source of fuel release and/or a source of ignition; and is more reliant on routine preventative maintenance to ensure safe operations. Without the presence of rotating equipment on a production platform, the probability of fire could be expected to be significantly decreased.

Pumps and compressors depend on various mechanical designs to prevent fluid leakage from escaping shaft penetrations, ranging from sophisticated double labyrinth seals and seal oil/buffer gas systems to simple packing glands. The reliability of seals varies considerably, and depends to a large extent on service conditions, including shaft RPM, shaft trueness and alignment, purity of lubricant, corrosiveness and sediment content of fluid being handled, and mechanical design. Routine seal system maintenance and inspection is required to maintain system integrity; however, LOC events from such failures are a known risk contributor.

Power drivers range from internal combustion engines and combustion gas turbines to large and small electric motors. Sparking, hot surfaces, breeches in the combustion chamber containment (open cylinder cocks), and mechanical failure can lead to ignition of escaped hydrocarbons. Lubrication oil leaks in contact with hot engine surfaces and diesel engine "runaways" due to ingestion of released vapors are two of the most frequently identified events associated with power drivers.

FLAIM has incorporated the following equipment items and piping considerations into its VESA assessment model.

5.2.2.1.1 Hydrocarbon Handling Pumps

Centrifugal pumps and positive displacement piston pumps, e.g., duplex and triplex pumps, are the two most commonly encountered types of pumps used for hydrocarbon handling in topsides operations. Pumps handling non-hydrocarbon materials or downhole pumps, such as large multi-stage horizontal split case centrifugal pumps used for waterflooding, vertical turbine pumps used for utility and fire water service, and downhole hydraulic or electric driven submersible pumps are not addressed herein. Fire pumps are treated separately in Chapter 9, Risk Reduction Measures.

Pump seals and packing glands are a known LOC contributor and should be expected to fail during operations without routine preventative maintenance and cyclic replacement. Aside from the normal service demands and deterioration that pump seals can be expected to incur, premature failure can be caused by failure of the shaft bearings in either the pump or driver, failure of the shaft coupling, and excessive heat caused by shaft rotation without adequate cooling or excessively tight packing glands. Excessive vibration can rapidly lead to seal failure.

FLAIM seeks to determine if all pumps handling hydrocarbon at significant quantities and flow rates, e.g., critically important hydrocarbon handling (CIHH) pumps, have been identified and categorized as high priority equipment items. In addition to compliance with API RP-14C, FLAIM asks if all CIHH pumps and drivers 1) are included in a preventative maintenance program, 2) are subject to a vibrational monitoring program that tracks and trends vibration levels for forecasting failures, 3) are equipped with vibration alarms, 4) are equipped with bearing temperature alarms 5) have pump cases and shafts constructed of steel or steel alloy materials, 6) have double mechanical shaft seals with seal failure alarms 7) have throat bushings to limit fluid flow in the event of seal failure, and 8) have remote pump shutdown controls that can be quickly accessed by operating personnel in the event of a fire.

The control system of automated pump shutdown valves on CIHH pumps, either motor operated (MOV's) or air operated (AOV's) should be either fireproofed or designed for fail-safe operation so as to ensure the integrity of these systems under thermal impact.

FLAIM also asks if pump case drain and vent fittings and similar threaded pump case connections have been seal-welded/bridge welded to minimize the risk of vibration induced fatigue failure. This is considered especially important in situations where valves, meters, or other objects are suspended (not independently supported) by virtue of the piping system, placing greater stress at threaded connections [see § 5.2.2.6 & 5.2.2.7].

5.2.2.1.2 Flammable Gas Compressors

Compressors handling flammable gas (for gas treating, shipping and/or reinjection) are identified in FLAIM as a high fire risk equipment item. Production platforms equipped with gas compressors can be expected to incur significantly higher fire loss rates compared with those platforms without compressors. Visser reports the results of a nine year study in which compressors were responsible for 65% of the fires and explosions.[4]

The risk of fire and explosions from compressors depends on several factors including the type and size of the compressor, driver, and lubrication system, as well as the temperature and pressure of the compressed gas.[5] In addition, the arrangement of the compressor area, spacing between units, the presence of other combustibles/fuels in the area, adequacy of maintenance and inspection practices, provisions for shutdown, blowdown, (depressuring), and protective instrumentation, e.g., vibration monitors, design of pulsation dampeners and surge control, extent and amplitude of induced vibration in associated piping, provision of adequate ventilation, piping and welding practices, combustible gas detection and fire detection systems, firewater deluge/water spray systems, etc. are important factors affecting overall firesafety.

There are two basic types of compressors used offshore: positive displacement (reciprocating) machines and kinetic energy (centrifugal) machines. Rotary (positive displacement) and axial flow (kinetic) compressors are generally not used for gas compression offshore.

Reciprocating compressors are considered to be constant capacity -- variable pressure ratio machines suitable for relatively low volume and high pressure services; typically engine driven, they are the long-standing workhorse of the gas processing industry. The are widely used for field gas compression for both gas transfer (sales) via pipeline to shore and for gas injection.

Centrifugal compressors, commonly driven by combustion gas turbines, are variable capacity -- nearly constant pressure ration machines suitable for high volume services requiring intermediate pressures. However large high pressure machines can be found in offshore service. For example, as early as 1976, Phillips Petroleum used two large centrifugal compressors rated at 9200 psia discharge pressure at 8426 RPM for gas reinjection in their Ekofisk field.[6]

Both types of machines have common fire risks, but also have risks unique to their design.

In general, compressor facilities have two attributes that increase their risk: they are one of, if not the most likely pieces of equipment onboard a platform to develop serious gas leaks; and, they represent both a potential fuel source and a potential ignition source (i.e., the compressor driver) in close proximity to each other -- normally without any physical separation between the two. It is always preferred to locate flammable gas compressors in the open on unenclosed decks that will allow released vapors/gas leaks and blast overpressures to dissipate in the open atmosphere (see Chapter 6, § 6.2.3). If enclosed, compressors modules/buildings should be provided with strong air handling systems and automatic gas detection systems.

5.2.2.1.2.1 Reciprocating Engine Driven Gas Compressor Sets

Reciprocating gas compressors are typically driven by gas fueled internal combustion (IC) engines operating at 1200 RPM; other drivers include dual-fueled IC engines, diesel engines, electric motors, gas or even steam turbines. However, by far most compressor sets are skid mounted engine driven "recips" that use treated field gas to operate. These machines do not present the same risk of lubrication oil-related fires as high speed centrifugal machines, since they do not have large, high pressure external force-fed lube systems. They are also easier to shutdown in an emergency and do not require long run-down times as centrifugal machines. Most engine drivers are considered potential sources of ignition and require careful design and maintenance to minimize the risk of fire (see 5.2.2.1.3, Internal Combustion Engines).

It is very important to ensure that incompressible fluids, e.g., liquids, do not enter into compressor cylinders to avoid rupture of the cylinder head(s). Inlet scrubbers/knockout pots (or drums) on the first stage cylinders and on intermediate stages with intercoolers should be provided with high level alarms (LAH) to warn operators of an impending problem. A high-high level shutdown (LSHH) should also be provided to automatically shut down the machine should operators fail to respond in sufficient time.

Other alarms should include low suction pressure, low and high discharge pressure, high discharge temperature, low lube oil pressure, and area combustible gas sensors if the compressor set(s) is located in an enclosed area.[7] In addition, ventilation of the packing area must be designed so as to prevent flammable gases from being forced into the crankcase. The distance piece enclosure, which is subject to gas accumulation from packing leaks, should be vented to a safe area outside the enclosure and equipped with a flame arrester.

All small piping connections should be either socket welded or, if threaded, seal welded, especially on volume or pulsation bottles; piping supports and bracing should support connecting valves and instruments so as to avoid any free-hanging, vibrating mass, supported solely by piping (See § 5.2.2.6 & 5.2.2.7).

Each compressor should have automatically operated shutoff valves at all suction and discharge lines that can be actuated from at least two separate and remote emergency shutdown stations/panels in the event of fire. Each machine should also have a remotely operated fail-safe, i.e., fail-open, depressuring system (blowdown valve or BDV) that will vent the machine to flare on actuation of the emergency shutdown system. Engine fuel gas valves should be also equipped with automatic fail-safe (fail-closed) shutoff valves actuated via the emergency shutdown system.

Pulsation dampeners and the use of long-radius pipe fittings can significantly reduce vibration and stress concentration-related failures. Each machine should be provided with a vibration monitor and automatic shutdown for run protection, as well as overspeed protection.

5.2.2.1.2.2 Centrifugal Gas Compressors

Centrifugal compressors operate at much higher speeds than recips and have high pressure lubrication systems that are external to the machine. They are most often driven by combustion gas turbines which, by themselves, also pose a potential fire risk.[8] Turbines normally operate at temperatures much above the autoignition temperature of lube oil, and consequently, any leaks that spray onto or otherwise come into contact with a hot turbine surface can be expected to ignite (see § 5.2.2.1.4, Gas Turbines)

The lubrication (lube) oil system includes oil reservoirs in which several hundred gallons of lube oil may be retained. In addition, the machine may have a seal oil system which incorporates an overhead seal oil tank. Buffer gas may be used to segregate the lube and seal oil systems. Occasionally lube oil reservoirs have experienced explosions which can spill large amounts of oil and cause widespread fire. One possible cause of this has been identified as buffer gas carryover into the reservoir followed by ignition due to static electricity.[9]

As discussed in § 4.2, fatigue failures from high frequency vibration that may be unnoticed can also lead to piping failures. Failure of small diameter piping may result in a gas leak or in a highly atomized spray or mist lube/seal oil that is easily ignited. Such failures are not uncommon and are reported in the literature.[10]

5.2.2.1.3 Internal Combustion Engines

Internal combustion engines (ICEs) are widely used offshore for a variety of services. Both diesel engines and spark-ignited engines fueled by gasoline, fuel gas, or liquefied petroleum gas (LPG) are utilized. Large ICEs are often used to drive reciprocating compressors, and may be fueled with either liquid or gaseous fuels (duel-fuel units). Fuel gas derived from onboard gas production and treated to engine specification is the most common means of fueling large ICEs in compression service.

Diesel engines may be utilized to drive the platform's main and/or standby electric generators, as well as in a host of other services such as fire pump drivers. In general, ICEs should be operated with due regard to the elimination of fire and explosion hazards as recommended in the Appendix of API RP 7C-11F.[11] Diesel engines located in or near Class I Division 2 electrically classified (hazardous) areas should be reviewed for conformance with the recommendations of OCMA Publication No. MEC-1.[12]

Both diesel and spark-ignited engines are potential ignition sources, primarily due to hot engine surfaces, e.g., the exhaust manifold and piping, or due to backfires. Sparking is also a concern with ICEs equipped with high tension ignition systems, electric starters, and electric generators/alternators with open arcing communicators. This type of electrical equipment can be a significant ignition risk contributor if not properly designed and maintained.

Engine exhaust systems are required to conform with the requirements of API RP 14C by OCS Orders.[13] This includes provision of an approved spark arrester on the exhaust stack and insulation of any surface over 400°F (or 160°F if a personnel hazard), or otherwise provide protection such as water cooled jacketed manifold/exhaust systems. Air intakes should also be provided with U.S. Coast Guard approved flame-arresting type air cleaners or an approved flame arrestors downstream of the air cleaner to prevent engine backfires from escaping to the open air.

MMS event database analysis indicates that diesel engine runaways caused by ingestion of released flammable vapors by engine air intakes have been a reoccurring problem in the past. Since May 31, 1989, OCS Orders have required that diesel engine air intakes be equipped with a means to automatically or, if normally attended, remotely shut down the engine by cutting of intake air. This can be accomplished by equipping diesel engine air intakes with airtight shutoff valves actuated by engine tachometers. FLAIM seeks to verify compliance with this requirement.

Spark-ignited engines driving flammable gas compressors are sometimes equipped with long lengths of high voltage (tension) wiring between the discharge side of the ignition coil or magneto and the spark plug. Such "high-tension" wiring is a known ignition risk factor and was commonly found in older compressor facilities. Breakdown of insulation and jacketing (formerly neoprene or rubber was used instead of modern high temperature rated silicon-compounds) decreased dielectric properties due to age, oil contamination, high temperature exposure, and breaks/cracks in the insulation can cause direct arcing/sparking between the engine block and distribution wiring.[14]

FLAIM asks if spark-ignited ICEs are used to drive CIHH pumps or compressors, and if the ignition coils (magnetors or transformers) are designed to be integral with or adjacent to the spark plugs, thereby eliminating the risk of high tension wiring discharge. In addition, ignition systems equipped with mechanical contact points can be replaced with solid-state systems without sparking contacts.

In general, engines located in classified (hazardous) areas should be air started rather than electrically started. ICEs should not be operated in Class I, Division 1 areas.

Switches and circuit breakers, and make-break contacts of relays, solenoids, push buttons, alarm bells, horns, etc., should have enclosures approved for Class I locations unless current interrupting contacts are either 1) immersed in oil, 2) in a hermetically sealed enclosure, or 3) are non-incendive, e.g., under normal conditions do not release sufficient energy to ignite Group D hydrocarbon vapors.

Motors, generators, and other rotating electrical machinery utilizing sliding contacts, centrifugal or other types of switching mechanisms (including overcurrent devices) or integral resistance devices, either during startup or when operating, should be approved for Class I locations or suitably enclosed. Motors and alternators without brushes, switching mechanisms or other arc-producing devices are suitable for Class I Division 2 locations, e.g., three phase squirrel-cage induction motors and alternators. Voltage regulators should be either solid state designs or provided with approved enclosures. Batteries should be provided with protective covers to reduce the risk of accidental cross terminal contacts.

Engine fuel lines should be made of seamless steel tubing or steel piping designed with flexibility and supported so as to minimize vibrational harmonics. Valves and fittings should likewise by made of steel. Rubber hose, copper and aluminum tubing, brass valves, and other low melting temperature materials should not be used.

Fuel lines supports should be arranged to provide at least a 2" clearance from exhaust and electrical system components. Fuel lines, valves, and fittings should be located so that leakage will not run off or drip on electrical devices or exhaust system surfaces. Downdraft carburetors on gasoline engines that have an external float bowl vent opening should have a vent overflow tube to direct fuel away from the engine in case of fuel overflow. Non-restricting steel shut-off valves should be provided adjacent to the engine on all fuel lines. Fuel headers supplying more than one engine should also have a manual main fuel shut-off valve located in a safe area so as to be accessible in the event of engine fire.

CIHH engine driven equipment and ICEs located within hydrocarbon handling areas should be equipped with instrumentation to warn operators of impending problems and to shutdown the unit automatically should the condition continue to worsen.

Engine cooling water and oil temperature, oil pressure, operating speed and vibrational amplitude, should be monitored and alarmed. On large machines above 1000 horsepower, it is also recommended to monitor the main bearing and connecting rod bearing temperature, as well as for smaller engines in critical services. Turbocharged engines should be equipped with low oil pressure and overspeed shutdowns on the turbocharger.

Automatic shutdown via the platform ESD system should result in positive shut-off of the engine fuel supply, e.g., closing an automated fuel gas supply control valve. In cases such as naturally aspirated four cycle engines and other engines where fuel shutoff is not rapidly achievable, ignition systems of spark-ignited machines should also be de-energized (grounded) on shut-down signal.

FLAIM asks how non-scheduled maintenance is predicted, e.g., if engine analyzers are incorporated in the platform's routine inspection and monitoring procedures in order to establish deterioration trends and predict major turnaround schedule requirements. FLAIM wants to know if there is a current predictive maintenance/problem procedure; if the procedure is based on manual interpretations of routine engine tests and operating data; or if the procedure incorporates trending analysis based on engine analyzers.

5.2.2.1.4 Combustion Gas Turbines

Aviation-derived combustion gas turbines are versatile and have proven effective for a variety of applications offshore. Gas turbines are used to provide platform power needs for electrical generators, gas compressors, and large pumps. Turbine-driven compressor or generator sets are commonly unitized (skid mounted) systems sold to offshore operators as packaged units. As such, control systems, alarms, and shutdowns are generally well designed and reliable. Most gas turbine packages are also provided with their own packaged fire protection system, e.g., Halon 1301 or Carbon Dioxide injection system that is automatically operated in the event of fire within the turbine enclosure.

Like internal combustion engines, gas turbines are a fire concern due to their high surface operating temperatures which are sufficient to ignite liquid fuel spills. Major fires can occur from leaks in or failure of the fuel system or lubrication and seal oil systems. The external surface temperatures around the combustion chamber and turbine expander may exceed 900°F, well above the autoignition temperature of fuels and lubricants (about 500°F for No. 2 fuel oil and bearing lube oils). Additionally, like centrifugal compressors, gas turbines operate at high speed and require a high level of preventative maintenance and inspection for safe operation. Lubrication systems operate at high pressures and normally should not be shutdown until such time that the machine ceased rotating. This results in delayed shutdown times to account for machine rundown.

On rare occasions a turbine blade may catastrophically fail from fatigue cracking, leading to extensive mechanical damage and possible fire and explosion. Inadequate maintenance or a malfunction in the lubrication system can also lead to bearing failures -- usually with serious property loss and fire consequences if a thrust bearing is involved.

When combustion gas turbines are employed as drivers for large hydrocarbon shipping or transfer pumps, splash barriers (walls) are frequently installed to separate the driver from the pump end in order to reduce the risk of hot surface ignition in the event of a seal failure leak or similar event involving the pump-end of the machine, e.g., the

Seadock Project -- two large pipeline pumping platforms constructed about 30 miles off Freeport, Texas in the GOM, circa 1974. Some operators require that turbine drivers be physically isolated from the hydrocarbon handling equipment that they are driving by fire walls, such as the pipeline pumps along the Alyeska Pipeline in Alaska.

Inspection and maintenance requirements for high speed machines are generally recognized as continuing high priority operating requirement that cannot be ignored without great risk. This includes both daily run checks, routine service inspections and instrumentation calibration/shutdown tests, and major turnarounds.

The type of fuel(s) used influence both the inherent fire risk as well as the expected life of machine parts and maintenance demands. Natural gas burning machines have the lowest risk of hot surface ignition and yields the longest parts life.[15] Diesel fuels, next to natural gas, result in the longest part-life of all commonly used liquid fuels. Crude oil and residual fuels produce higher radiant heat outputs and are more difficult to atomize effectively, resulting in shorter part-life and higher maintenance demands. Crude-fueled machines are also at higher fire risk due to the higher vapor pressure-lower flash point of crude compared to diesel. Parts wear and maintenance for dual-fueled machines varies with the amount of run time using any one fuel.

Safe operation of gas turbines involves proper instrumentation as well as maintenance. API Standard 616, *Combustion Gas Turbines*, should be followed as a basic guide to system design. Emergency shutdown controls should provide for system redundancy, providing backup to primary shutdown functions. Emergency shutdowns should include overspeed, flameout, vibration and fire detection/high temperature. Safety shutdowns should be routinely tested on a monthly basis or otherwise in accordance with current recommendations of the manufacturer.

FLAIM has limited the treatment of combustion gas turbines to questions dealing with inspection, maintenance, and location/ignition risks as well as past operating experience.

5.2.2.1.5 Electric Motors and Generators

Electric motors of all sizes can be found on offshore platforms. GOM platforms tend to limit the size of motors in order to keep electric generator plant size within reason, relying more on engine driven equipment for larger applications. This is one area of major departure from North Sea platforms where large electrical generating plants and power distribution systems are more commonly employed, and the use of large electric motors is favored. However, large motors of 500-1000 hp or more may be encountered on some platforms.

Process areas on production platforms are generally deemed to be adequately ventilated, and are accordingly electrically classified as Class I Division 2 areas (see § 6.3, Electrical Area Classification). Motors in Division 2 areas must be non-sparking designs. Class I Division 1 areas which require the installation of explosion proof motors are either very limited in extent, or do not require the presence of motor driven equipment. Consequently, most motors used in offshore production applications are 3-phase non-sparking squirrel cage induction motors. Totally enclosed motors are generally preferred to open designs to minimize exposure to the saline environment. Larger TEFC (totally enclosed fan-cooled) integral horsepower motors in NEMA frame sizes (NEMA II weather protected) are available with sealed insulation systems, non corrosive and non sparking fans other features preferred for offshore applications.

Surface operating temperatures must conform with the limitations set for in the National Electrical Code[16] for Group D hazardous atmospheres. The ignition temperature of natural gas is considered to be about 482°C. Electrical devices exceeding 80% of this value, e.g., 386°C, must be installed in explosion proof enclosures or be certified as a "T1" temperature device (not to exceed 450°C). However, if ignitable concentrations of gases may be present with lower ignition temperatures than that of natural gas, then the surface temperature restriction must be based on 80% of that gases ignition temperature or have a suitable temperature rating certification. Motors with sparking or arcing contacts, such as single phase motors, may be used in Division 2 areas if they are equipped with clean-air purge systems per NFPA 496,[17] or if the contacts are immersed in oil or hermetically sealed, or contained with an explosion proof enclosure.

Electric motor driven process pumps can cease and overheat due to bearing failures. Motor overheat protection is required to trip-out power at motor control centers in such circumstances. Occasionally, some companies will jumper the thermal protection device of motors so as to ensure motor operation regardless of temperature conditions. For example, the practice is not uncommon on motor operated emergency shutdown valves (MOVs) and critical process control valves.

FLAIM asks if platform motors, generators, and electrical distribution systems are properly installed and protected in accordance with the recommendations of API RP 14F.[18] This version of FLAIM does not include a separate evaluation of firesafety risk factors related to fires of an electrical nature, such as the risk of transformer failures and explosions, short circuit and locked rotor current protection design adequacy, etc. FLAIM does however, consider the risk of ignition caused by improperly installed or maintained classified electrical equipment.

The power generation/utility area is normally electrically unclassified area in which ordinary (non-classified) electrical equipment may be located (see § 6.2.4, POGU Area). Revolving field, brushless type generators eliminate all arcing contacts and reduce maintenance requirements offshore. Open drip-proof generators are suitable for installation in enclosed power generator modules; however, when located on open decks, generators that are totally enclosed and equipped with space heaters are preferred. In the event of a large gas release, arcing and sparking electrical equipment throughout the platform is a serious concern. FLAIM also seeks to determine if platform electrical equipment can be safely and rapidly de-energized from a central location.

5.2.2.2 Fired Heaters and Fired Pressure Vessels

The presence of fired equipment on a production platform can increase the risk of topside fires, e.g., heater-treaters used in emulsion treating, glycol regenerators used in gas dehydration, steam generators and packaged boilers, etc.[19] The risk of fire depends on several factors including heater design, instrumentation and shutdown automation, operating conditions (pressure, temperature, flowrates, etc.), corrosivity of the production fluids and environment, drainage and curbing, isolation and fire protection, and spacing and location of the equipment on the platform. Visser found that the fire risk of fired equipment is significant, but less than that posed by compressors or storage tanks.[20]

Fired equipment presents both a potential source of ignition from open flames and hot surfaces, as well as a source of fuel release and fire in the event of fire-tube or fuel line failure. Direct fired heaters pose the greater risk since failure of a tube can introduce production fluids directly into the fire box. Indirect fired heaters, e.g., those without radiant heating sections and that use low fire risk heat transfer mediums, do not pose the same degree of risk as direct fired designs in which production fluids are directly heated.[21] Natural draft designs are also considered to present a higher ignition risk of vapor/gas releases (flashback risk) than forced draft/induced draft designs in which the combustion air velocity exceeds the fundamental burning velocity of natural gas.

Onshore petroleum facility statistics indicate that fired heaters and rotating equipment (pumps and compressors) are the two equipment groups most often involved in fire. Nearly one-third of all reported refinery process unit losses are attributable to fired heaters.[22] A survey performed by Gale in the early 1980's indicated that human error was a predominate cause of losses involving fired heaters (60-70%), especially involving startup operations, whereas mechanical failure (tube rupture) and improper design (instrumentation) accounted for most of the other losses. Although the number, size and complexity of onshore fired equipment certainly affects the loss rate, the type of failures and their causes are of interest to offshore operators.

Many production platforms employ some type of fired equipment to control production fluid temperatures, treat emulsions, provide utility needs, and dehydrate produced gas. Glycol reconcentrators or reboilers have been shown to be a reoccurring fire problem offshore. Glycol's high modulus of thermal expansion has led to many incidents of overfilling and spills that become rapidly ignited. The ensuing fires can be initially large and difficult to control. Direct fired heaters that handle production fluids are notorious for tube failure fires and are prohibited by some offshore operators.[23]

During the early days of the GOM development, little if any gas processing was done offshore and fired heaters were not used. As production rates increased however, it became necessary to perform more extensive onsite treatment of production fluids. Many field developments were in shallow waters and could justify two platforms: a main production platform and a second auxiliary or "Hot" platform on which steam generators, glycol reboilers, heater treaters, and other fired equipment items were located. As field development continued its expansion into deeper waters, separate platforms were no longer considered to be economically viable, resulting in fired equipment installations on wellhead platforms.[24, 25]

FLAIM seeks to determine if 1) fired heaters of any type are located on a production platform containing wellheads and process equipment, 2) the type of fired heaters installed, (protected, natural draft v. forced draft, indirect v. direct, convection v. radiant, etc.), 3) their number and location (multiple locations v. single local, upwind, etc.), and 4) the protection provided (curbing and drainage, instrumentation/alarms combustion controls, ESD, fire detection and suppression, etc.).

FLAIM makes these determinations by asking key questions as listed in Appendix B2. FLAIM asks if all fired vessels are designed as protected units (Low Ignition Risk) in accordance with the definition of API RP 500B.[26] Protected fired vessels are designed in such a manner so as to eliminate the combustion air intake and exhaust stack (and other hot surfaces) as possible ignition sources. Refer to § 6.2 for fire equipment layout and configuration considerations.

5.2.2.3 Atmospheric Storage Tanks and Vessels

Flammable liquid storage tanks and vessels are significant risk contributors and, according to Visser, increase fire risk about as much as the presence of flammable gas compressors.[27] They are vulnerable to both fire exposure, as well as spills from overfilling, mechanical impact, and lightning strikes. Risk reduction measures aimed at reducing the onboard inventory of flammable and combustible liquids will enhance the inherent level of platform safety. FLAIM asks how much flammable liquid inventory is normally maintained on the platform, and the number, size and spacing of storage tanks.

Welded steel storage tanks used for storage of crude oil, natural gas liquids, methanol, glycol, and other flammable liquids should be constructed to API Standards, e.g., Std. 12F, 620 or 650. [28] ASME coded pressure vessels may also serve for crude oil storage. FLAIM asks if storage tanks made of fiberglass or other plastic materials are used, or if tanks erected from bolted plate are present on the platform.

A study[29] performed for the API Committee on Safety and Fire Protection on onshore above ground storage tank accidents between 1970 - 1988 found that other than vandalism, the most frequent event (15.2%) leading to loss of containment was overfilling of the tank. Open valves (4.3%), inadequate maintenance (4.3%), corrosion (4.3%) contributed equally to the frequency of events. Overall, at least 40% of all reported losses are directly attributable to human error.

Corrosion in offshore crude oil storage tanks can be expected to be more severe than for their onshore counterparts, especially where wet H_2S may be present with air in the vapor space. Internal corrosion in tanks occurs in three general zones -- the underside of the roof, along the walls, and on the tank bottom. White reports that the highest rates of roof corrosion occur when H_2S reaches 0.5% in the vapor space. Inert gas blankets reduce this problem. Shell corrosion is a function of wall height and the frequency in which tanks are filled and emptied; reaching a maximum metal loss rate at a location between 80% to 90% of the tank height. Bottom corrosion is accelerated by the lower water layer that is normally present in crude oil storage tanks. Sulfide forming bacteria can also lead to H_2S production and corrosion.[30]

It is important that tank nozzles located below the liquid level be equipped with shutoff valves, preferably bolted directly to the tank nozzle without intervening sections of piping. This reduces the risk of line failure between the first shutoff valve and the tank, damage to which could lead to loss of the tank's contents. Tank valves made of materials other than steel, such as cast iron, increase the risk of mechanical failure and should be replaced. Tank nozzles below the normal liquid surface level may be equipped with thermal actuated self-closing valves that will close if exposed to fire.

Fixed roof tanks and vessels that are normally used for flammable liquid storage should be preferable equipped with gas blanketing or inerting systems so as to maintain the vapor space above or otherwise out of the flammable region. This is particularly important in lightning prone areas where frequent electrical storms are anticipated.

To minimize the consequences of overfill, tanks and vessels used for flammable liquid storage should have overflows piped to a safe disposal area. High level alarms and high-high level safety switch shutdowns on transfer pumps are also risk reduction measures that FLAIM assesses. Venting provisions and alarm instrumentation should be in accordance with API RP 14C and API RP 2000. Protection for overfill should be in accordance with API RP 2350.[31]

Elevated storage tanks and vessels should have structural supporting members fireproofed or otherwise protected with fixed water spray deluge systems so as to retard collapse and allow time for fire-fighting efforts.

Imposed environmental loads from non routine events should also be accounted for in storage tank designs to minimize the risk of LOC accidents. Storage tanks and associated piping should be analyzed for structural robustness in seismic events, high wind loads (e.g., hurricanes) and, in cold regions such as the Cook Inlet, additional loads caused by ice build-up on tank roofs. Materials of construction must also be compatible with anticipated low temperature ranges, i.e., use of low temperature steels. Where such considerations are appropriate for the region in which the platform is located, FLAIM may be modified accordingly to address these concerns.

5.2.2.4 Pressure Vessels

A study conducted for the U.K Health and Safety Executive found that on a worldwide basis, the direct and underlying causes of process pipe and pressure vessel failure in 80-90% of all cases is due to deficiencies in the management system, e.g., inadequate maintenance and inspection, lack of hazard identification, etc.[32]

As already mentioned in § 4.3.1, most oil and gas separators do not, in general suffer from significant metal loss corrosion, but rather are subject to buildup of scale and sediment leading to decreased efficiency. However, offshore platform pressure vessels operating in wet H_2S environments may be experiencing extensive sulfide stress cracking which has heretofore gone undetected.

The extent of this problem offshore is unclear; however, there is reason for concern. Results from recent large-scale inspection programs of petroleum refinery pressure vessels in wet H_2S service (more than 50 ppm H_2S) show that overall about 25% of all vessels inspected had cracks. Some individual companies found the cracking rate for their vessels as high as 45% and the severity of cracking in many cases required removing the vessel from service. A 1988 API survey reported that about 75% of the cracked vessels had crack depths greater than the corrosion allowance, and about 1/3 of the cracked vessels were replaced. [33]

FLAIM asks if onboard pressure vessels and their pressure-relieving devices are being inspected and maintained in accordance with Section 6, Alternative Rules[34] for Natural Resource Vessels of API 510.[35]

Further FLAIM asks if pressure vessels in CIHH services have been post-weld heat treated (PWHT) and if documentation on engineering data and inspection results has been maintained and is up to date. In wet H_2S service, FLAIM asks if a wet florescence magnetic particle inspection has been conducted to determine the extent of stress cracking that may be present, and if systems have been designed to NACE Standard MR-01-75, *Standard Materials Requirements - Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment,* National Association of Corrosion Engineers.

5.2.2.5 Heat Exchangers (Unfired)

Leaks of process fluid from heat exchangers can contribute to platform fire escalation. Air cooled exchanger, e.g., fin-fan air coolers, can fail rapidly if directly exposed to fire -- especially if the cooler is in gas service. Fin fan coolers are very effective cooling devices that force or induce ambient air over tubes containing hot process fluids. Conversely, the can be very effective heating devices when air temperature is elevated by convective heat rising from deck-level fires.

Overhead air coolers are equipped with forced draft or induced draft fans that create strong updrafts that can draw in flames from liquid pool fires below. This can cause overpressuring and failure of cooler tubes. In gas coolers, the absence of liquid in the tubes can result in sudden thermal stress failure, releasing high pressure gas to further escalate the developing fire situation.

Unlike air cooled exchangers which can have their heat transfer surface exposed directly to fire, shell and tube exchangers are less vulnerable. However, failures of shell and tube heat exchangers due to either tube failure or fire exposure can also contribute to further escalation. Failure of tubes may be caused by several factors including corrosion, vibration, transient pressure surges, and thermal excursions. Failures can vary from a leaking tube or tube-sheet to the complete rupture of one or more tubes. High pressure production fluids can be released into the low pressure cooling or heating side of the exchanger, possibly resulting in overpressuring lower pressure rated equipment.

Tube and shell exchangers should be designed to the requirements of the ASME pressure vessel code, API standards 660 and 661, and protected in accordance with API RP 14C. Of particular importance is ensuring adequate relief capacity to prevent overpressure failures caused by fire exposure. The relief capacity of all platform shell and tube heat exchangers should be consistent with the recommendations of API RP-521.[36]

5.2.2.6 Piping, Valves, and Piping Components and Practices

Piping and piping components are vitally important to preventing initial releases of production fluids as well as limiting vulnerability to escalation. FLAIM has identified several piping-related risk contributing factors for incorporation into the risk index algorithm.

Low melting temperature materials and materials with low ductility (cast iron) should not be used in hydrocarbon services. FLAIM asks if all topside piping systems are constructed of seamless steel or steel alloy pipe, and if all valves and fittings are made of carbon steel. Brass, cooper, aluminum, plastic and rubber and similar low melting temperature materials will fail rapidly under fire exposure conditions.

In general, topsides process piping should conform to the requirements of ANSI B31.1[37], as modified by API RP-14E.[38]

Low cost seam-welded line pipe, such as butt-welded API 5L ERW (electric resistance welded) line pipe, is more prone to failure than seamless steel pipe, and should not be used in CIHH services. Seamed pipe may have hydrostatic failure rates of fifty times high than that of more expensive seamless pipe, e.g., one failure of ERW pipe/10 mile v. one failure of seamless pipe/500 miles. [39] Larger diameter seamed pipe fabricated from plate in wet H_2S services has also recently come under scrutiny due to its greater susceptibility to sulfide stress cracking than seamless pipe.[40]

FLAIM asks if all topside hydrocarbon piping is seamless steel construction designed to meet the requirements of ANSI B-31.3. Additionally, FLAIM seeks to determine the extent to which piping components and valves in hydrocarbon service are fabricated from materials other than steel, e.g., cast iron, malleable iron, nodular iron, etc. Cast or ductile iron valve bodies should not be used for hydrocarbon or glycol services due to low impact resistance.[41]

Some valve designs such as ball valves and plug valves may depend on elastomeric materials for sealing the valve stem from leakage. Under fire, the seal material will rapidly deteriorate resulting in valve leakage. FLAIM asks if all valves in hydrocarbon service that utilize soft-seating and packing materials have been fire tested to meet the maximum allowable leakage criteria of API Standard 607.[42]

Some commercial piping components used for coupling piping sections together rely on elastomeric materials to retain fluids. Such quick-connectors and compression sleeve couplings, e.g., Dresser couplings, Victaulic couplings, etc. may be prone to leakage under fire exposure conditions and, in general, should be avoided in platform hydrocarbon piping systems.[43] Pipe clamps for "temporary" repair of minor leaks are also manufactured using similar sealing materials. Once installed, however, their temporary quick-fix purpose is often forgotten. FLAIM asks if any of these types of piping components are in use in hydrocarbon handling services.

Flangeless, wafer-type valves that are designed to be inserted and held in place under compression between two flanges are known fire risk contributors. Wafer-type butterfly, check, and control valves can quickly lose integrity under thermal impact (within five minutes) as the flange bolts (studs), which are exposed, elongate as they become heated and decrease the compressive restraining forces around the valve. Such valve designs can significantly increase a platform's vulnerability to escalation.

Threaded piping is susceptible to stress concentration effects and vibration induced fatigue failure. Preferably, small diameter piping should be socket-welded rather than threaded. Threaded piping in hydrocarbon services should be generally limited to pipe under two inch diameter in size and exposed threads should be seal welded. A full size fillet weld should be made, extending from the threads to the full outside diameter of the female fitting into which the pipe is screwed. All threaded portions of the pipe nipple being seal-welded should be covered with weld material. Care must be taken not to undercut. For very short sections of threaded pipe, e.g., 1" to 6" nipples, the seal welds covering the threads on both ends should be bridged. Bridge-welded, e.g., continuously welding across the entire length of the nipple from one fitting (boss) to the next eliminates individual fillet welds and the points of stress concentration that occur at the toes of the welds.

Small diameter threaded branch connections, such as drains and vents, that directly supports freely suspended valves and other piping components which are not otherwise braced or provided with external support struts are particularly subject to fatigue failure at the root-connection due to notch effects. This is especially a problem in piping associated with high pressure compressors where even small valves and piping components are heavy, increasing the amount of suspended mass (overhanging weight or pendulum effect) and further concentrating cyclic stresses at threaded root-connections. Freely vibrating valves and small diameter piping associated with compressors should be provided with external bracing and the root connection should be bridge-welded back to the first shut off valve. In some cases, small threaded pipe nipples can be eliminated by installing root-valves, e.g., valves with threaded male connections that can be screwed directly into pump or compressor components, such as vents and drains on pulsation dampeners and suction bottles as shown on **Figure 5-1** below.

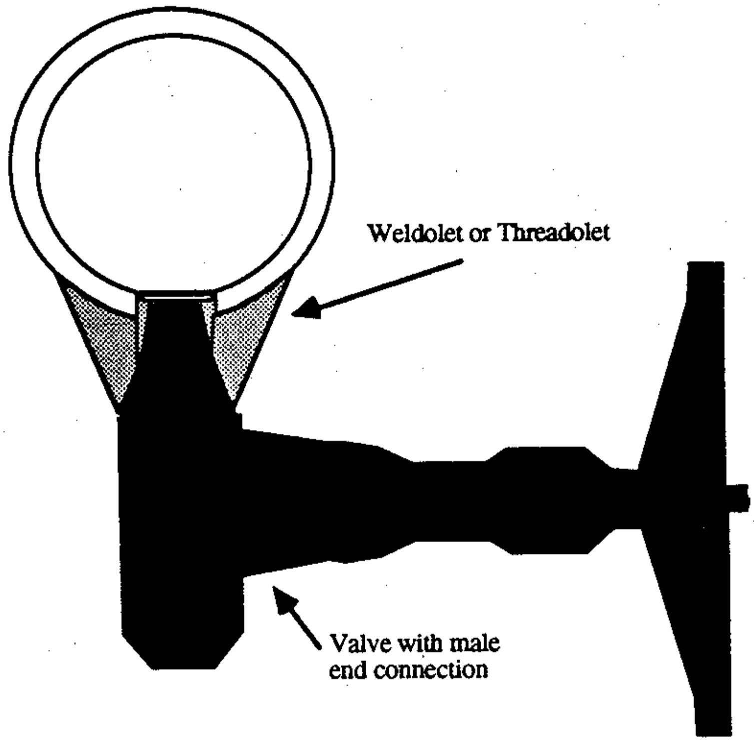


Figure 5-1
Typical Root Valve
Connection

Piping two inches in diameter and larger can be butt welded or flanged. Flanged connections can leak when exposed to fire; hence flange design is relevant to firesafety. Welding-neck flanges are preferable for use in lieu of slip-on and socket-weld flanges for all 2 inch and larger pipe in hydrocarbon handling services. Flanges in the wellbay and in other high pressure hydrocarbon services preferable should be API 6A rated flanges certified to fire test requirements in SPEC 6FB. Part I of this specification was especially designed to evaluate performance under fire conditions that are representative of open type offshore platform fires, with the exception of the wellbay in which thermal loads are greatest. Wellbay fire test requirements are covered in Part II.[44]

ANSI B16.5 flanges are also commonly used in offshore hydrocarbon services. Raised faced (RF) flanges afford ease of maintenance and facilitate equipment change, but do not have the same degree of integrity as ring-type joint (RTJ) flanges. RTJ flanges are preferred to RF flanges in higher pressure/high temperature hydrocarbon handling services and where vibration is pronounced. They are less likely to leak than RF flanges. Flat face (FF) flanges are used for mating with non-steel flanges on, for example, cast iron pump bodies or cast iron valves. Flat face flanges should generally not be used in hydrocarbon handling services offshore. API Bulletins 6F1 and 6F2 provide additional information on fire test performance of API and ANSI flanges.[45, 46]

Flange leaks can present difficult fire control situations, especially if the escaping hydrocarbons are under high pressure. With regard to pipe leaks, flange gaskets can be generally considered the "weak-link" in the LOC chain of events. A gasket serves as a compressible retaining seal that compensates for irregularities in the mating surfaces of a flange set. Gaskets must be suitable for the pressure, temperature and fluid service for which they are intended.

Gasket materials age and deteriorate under the constant assault of both external and internal corrodants. There is also considerable margin for human error during their initial installation or replacement -- especially with some types of unconfined gaskets which require careful centering. In a fire, the bolt loading holding flange faces together will begin to relax as the thermal impact causes bolts to expand. The hydrostatic end force within the pipe which tends to push the flange faces apart, in opposition to the bolt loading, and internal pressure which acts against the exposed edge of the gasket -- tending to blow it out, may increase significantly as temperature builds. This is especially true if actuation of the ESD system results in blocked-in liquid packed line sections that have no thermal relief devices. The residual force holding the gasket in place, e.g., the net difference between the bolt loading, the hydrostatic end force, and the internal pressure, can rapidly become inadequate to retain process fluids.

Spiral wound gaskets with stainless steel windings, e.g., Flexitallic-type gaskets, are preferred for use over conventional composition gaskets for ANSI raised face flanges. Ring gaskets for API and ANSI ring type joints should conform to API SPEC 6A, SPEC 6FA, and/or 6FB (refer to § 5.2.2.7, Wellheads and Wellhead Surface Safety Valves, for additional information). FLAIM asks if all flanged connections are provided with spiral wound gaskets.

Piping sections that can be blocked in between two shut off valves may experience overpressure should the temperature of the trapped liquid be raised. This also applies to certain valve designs in which liquids become trapped when the valve is closed, e.g., double block and bleed valves and some types of plug, globe and gate valves, (e.g., certain Pressure Seal Valves). Thermal relief valves should be provided in such cases to avoid overpressures failures under fire conditions and limit escalation of the situation.

Expansion joints using bellows assemblies are also susceptible to fire damage and subsequent leakage. Bellows-type expansion joints should, in general, not be used in hydrocarbon services.

Equipment vents and drains are a frequent source of unwanted hydrocarbon release in the process industries. Vents and drains that are pocketed can be subject to corrosion and plugging. In general, vents and drains should be kept as short as possible and provided with double block and bleeds.

Field fabricated piping can have lower levels of weld quality than shop fabricated spool pieces. Weld quality is vitally important to ensuring the integrity of the process system. FLAIM seeks to identify any sections of hydrocarbon piping systems that may have inferior/suspect welds due to field fabrication and asks what percent of the welds have undergone radiographic weld examination.[47]

5.2.2.7 Wellheads and Wellhead Surface Safety Valves

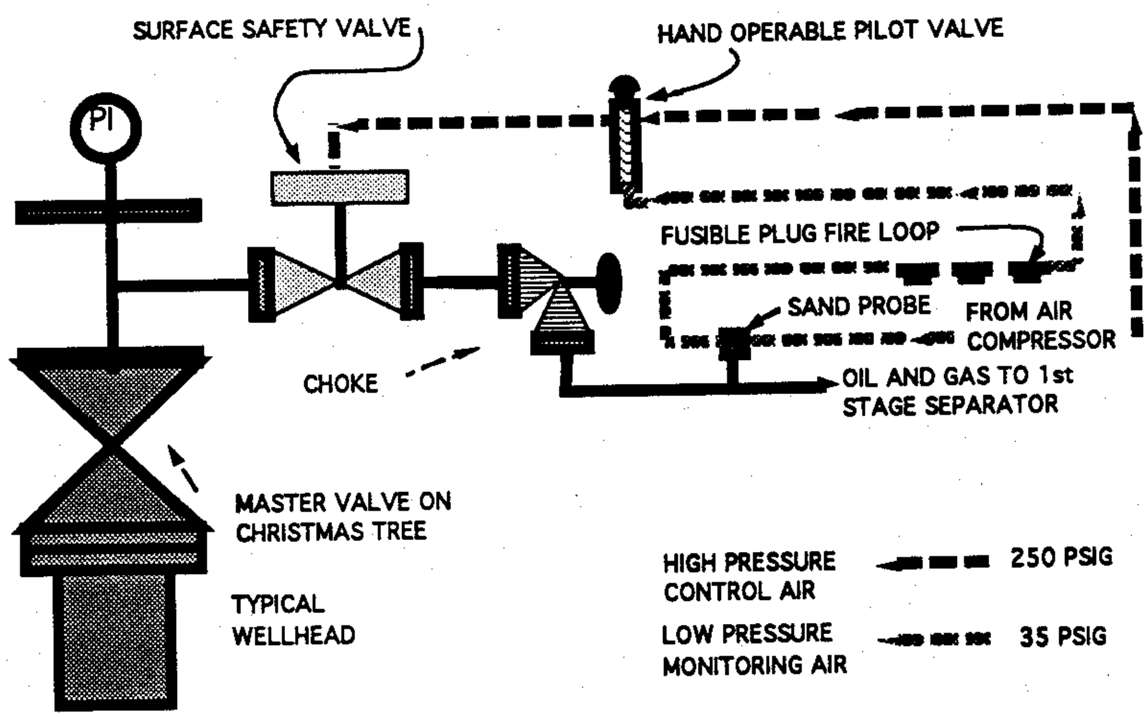
Wellhead and Christmas tree equipment should be designed to one of four production specification levels (PSL) as defined in API Specification 6A.[48] All wells located in state or federal waters should be considered as "close proximity wells"[49] in assessing potential risks of LOC events on fire and life safety. The appropriate PSL for the primary parts of offshore wellhead assemblies, e.g., close proximity wells, is determined by the required rated working pressure and the amount of H_2S present in the produced fluids.

Offshore wellhead assemblies that are required to conform NACE Standard MR-01-75 for sour service (see § 4.3.1 and **Table 4-3**) must meet or exceed PSL 2 in all cases, regardless of pressure rating. In addition, if the concentration of H_2S is sufficiently high in the well stream so as to possibly result in airborne concentration from leaks greater than 100 parts per million (PPM) within 50 feet of the wellbay, then the wellhead must meet or exceed PSL 3 in all cases, regardless of pressure rating.

FLAIM asks if wellhead assemblies on existing platforms meet the appropriate PSL specification for the service conditions of each wellhead onboard the platform.

FLAIM also asks if all Christmas tree valves and end connections are certified for maximum leakage under fire conditions in accordance with API SPEC 6FA and API SPEC 6FB. [50]

Wellhead surface safety system valves (SSVs) are vitally important to overall platform safety and are a key element of the basic surface safety system as described in API RP 14C. SSVs should be the second valve in the wellhead flowstream e.g., the wing valve or top master valve. SSVs and their actuators (usually pneumatic) should meet the appropriate service class as specified in API Specification 14D.[51] Refer to **Figure 5-2**, Surface Safety Valve Control System.



Typical Surface Safety Valve Control System

Figure 5-2

System Description: the pneumatically operated surface safety valve (SSV) is designed to be a normally closed (fail-safe) valve that is held open by high *pressure control air from the platform utility system. A normally closed pilot valve, held open by low pressure monitoring air, allows high pressure control air to pressurize the SSV pneumatic operator, thereby maintaining the SSV in an open position. Loss of monitoring air causes the pilot valve to close and to vent the high pressure control air on its down stream side to atmosphere, thereby causing closure of the SSV. The pilot valve can be either directly actuated by manual operation, or is operated by loss of monitoring air pressure either due to the operation of a sand probe (from erosion), a fusible plug (from high temperature due to fire exposure), or by a manual ESD station. Solenoid valves may also be placed in the low pressure monitoring air system to permit remote manual operation via electric manual stations or via telemetry.*

SSV Class 1 service applies to wellstreams that do not pose serious corrosion or sand erosion problems. Class 2 covers those wells where sand erosion can be expected to cause failure of the SSV(see § 4.5). Class 3 applies to situations where conditions for stress corrosion cracking are present, and is subdivided into two subclasses -- one for sulfide stress cracking (Class 3S), and one for chloride stress cracking (Class 3C). Class 4 applies to wellheads where high rates of metal loss may occur from corrosion (see § 4.3.1).

Inspection and maintenance of platform SSVs is of prime concern to FLAIM and conformance with the provisions of API RP 14H[52] is assessed. SSVs are required by OCS Orders[53] to be tested for operation and for leakage at least once each calendar month, but at no time longer than at more than six week intervals. Closure time for SSVs should not exceed 45 seconds from time of actuating the ESD system or automatic detection of an abnormal condition by a safety sensor.[54]

5.2.2.8 Subsurface Safety Valves (SSSVs)

Subsurface safety valves (SSSVs) are most upstream and, correspondingly, the most single important well control safety element on a production platform. There main purpose is to stop uncontrolled flow from the well in the event of damage to surface control elements, e.g., the wellhead and Christmas tree, as may be caused by a dropped object or an explosion and fire in the wellbay. SSSVs may be actuated by platform surface safety systems, i.e., a surface controlled subsurface safety valve (SCSSV), or may be subsurface controlled (SSCSV). All production or gas injections wells on the OCS that are capable of flowing under natural conditions (without artificial assistance) are required to be equipped with SCSSVs in accordance with OCS Orders.[55] These are usually hydraulically operated valves. See **Figure 5-3.**

SSCSVs (storm chokes or velocity type valves) can be used in place of SCSSVs in some circumstances, but their use has been generally phased out due in favor of surface controlled valves. In the past storm chokes have proved to be unreliable. They rely on excessive flow velocity to actuate valve closure. They cannot be actuated nor tested from the surface and require removal for testing. Older platforms may still have wells completed with SSCSV. FLAIM considers this in its assessment algorithm.

SSSVs are classified[56] in accordance to the service conditions similar to SSVs, except that there are only three different groupings: Class 1 for standard service conditions, Class 2 for sandy service where erosion could cause failure, and Class 3 for stress corrosion cracking service which is subdivided into Class 3S for sulfide stress corrosion cracking environments and Class 3C for chloride stress corrosion service. However, unlike API SPEC 14D for SSVs, SPEC 14A does not include a separate (fourth) class for corrosive services in which metal loss could lead to failure.

Inspection and maintenance of platform SSSVs is also of prime concern to FLAIM and conformance with the provisions of API RP 14B[57] is assessed. SCSSVs are required by OCS Orders[58] to be tested for proper operation and leakage at least once every six months. SSCSVs must be removed from the well and inspected on six to twelve month cycles depending on if the valve was installed in a landing nipple. Closure time for an SSSV should not exceed 2 minutes from time of closure of the well's SSV.[59]

Some SCSSVs are equipped with isolation valves near the control line wellhead outlet. Closure of this valve will isolate the SSSV from the surface control system; FLAIM seeks to determine what management controls are in place to ensure this valve is not accidentally closed or left in a closed position for an extended period.

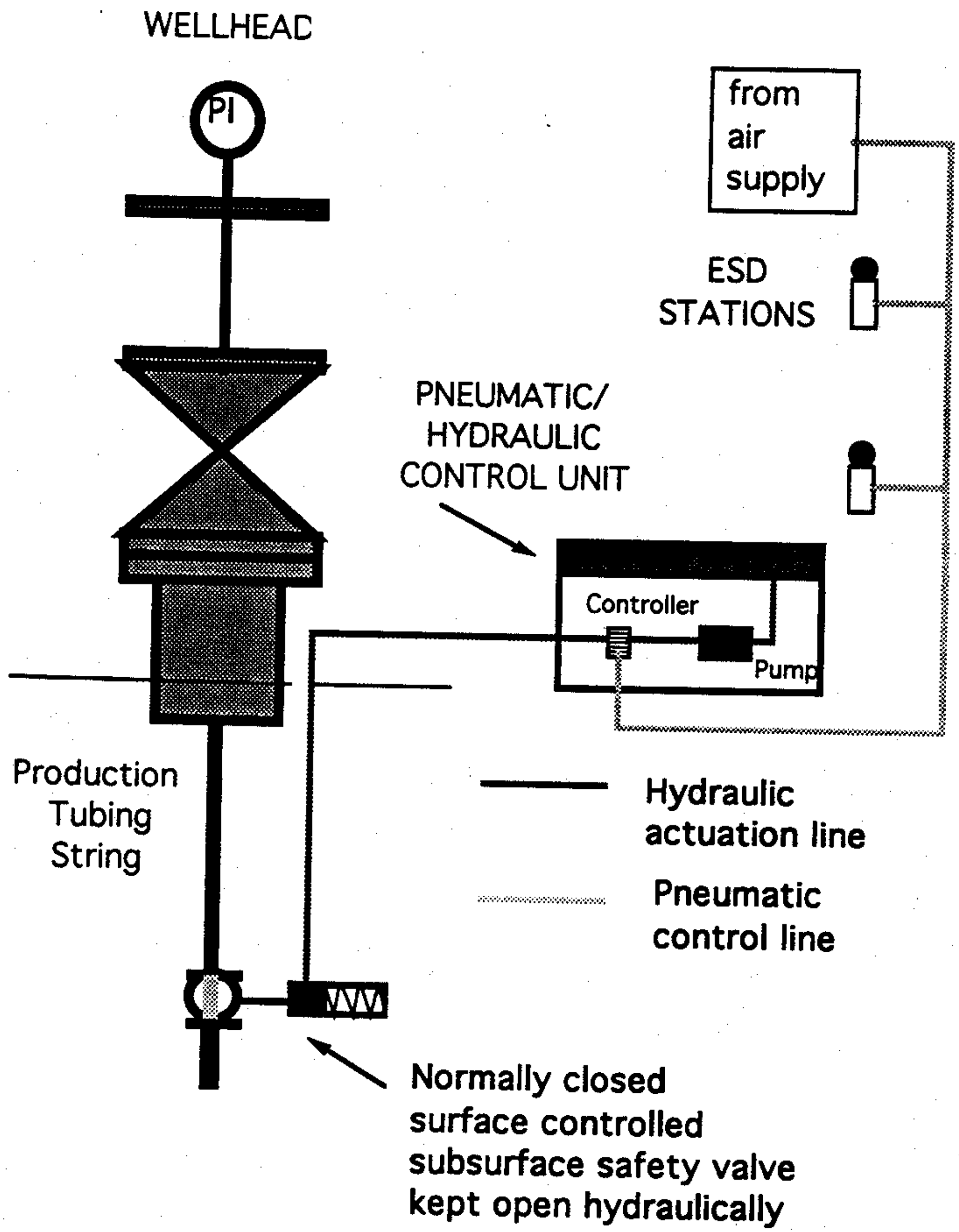


Figure 5-3

Typical Surface Controlled Subsurface Safety Valve System

5.3 *SPECIAL SYSTEM RISK FACTORS*

5.3.1 Gas Treating Using Glycol

Gas dehydrating systems using glycol have been shown to be a reoccurring firesafety problem on production platforms. Glycol regenerators (reconcentrators) employing direct fired reboilers are a frequent fire source. This is partly caused by glycol's thermal expansion characteristics, and partly due to operators tendency to overfill makeup tanks. Regenerators are specifically addressed in the OCS Orders which require provisions to guard against overpressuring these vessels.

FLAIM asks if the platform has a glycol regenerator and what the onboard fire experience has been in its operation.

5.3.2 Platform Pipeline Risers

The failure of a high pressure platform export or import riser is potentially catastrophic, as evidenced by Piper Alpha.[60] Riser mechanical integrity is a vital safety consideration and topsides risk factor. The risk of riser failure due to external events, e.g., impact by boat collision of falling objects, material failure, e.g., deterioration from corrosion/erosion/sulfide stress cracking/fatigue, etc., and human error, e.g., improper operation (overpressure), improper work planning (e.g., ARCO South Pass Block 60 Platform B) should be the subject of a separate risk analysis study.

FLAIM evaluates the need for such a study by asking about the number of and age of platform risers, the state of knowledge about their mechanical integrity, the frequency of inspections and methods used, the service conditions (pressure rating v. operating pressure) and characteristics (slug flow, extent of vibration), and their location with respect to other platform areas, such as the crew quarters. In addition, FLAIM asks if a subsurface safety valve has been installed in addition to the surface safety valve., and how often the safety valves are fully tested.

5.3.3 Welding and Hot Work

Welding and hot work has been designated as a special systems risk factor due to the pervasive nature of this problem on offshore production platforms. Escalation of LOC events as a result ignition by welding and hot work is a reoccurring problem offshore. This issue is addressed in Chapter 10, Safety Management Systems.

5.3.4 Instrument & Electrical Systems and Equipment

Platform instrument and electrical systems generally perform vital safety functions during both normal operations and emergency situations. Many factors can decrease system reliability such as corrosion of electrical contacts, poor grounding of equipment, deterioration of electrical wiring, and exposure of cable trays and data highways to fire and blast effects. Personnel safety is also at issue with regard to the inherent problems of operating electrical powered equipment on a steel structure in a marine environment.

Electrical powered equipment can be a potential source of ignition for released flammable vapors. Classified electrical equipment, intrinsically safe electrical equipment, nonincendive electrical equipment, and purged and pressurized electrical equipment are all used to reduce the risk of ignition in areas where flammable vapors may be released. Issues of electrical area classification are addressed in § 6.3, *AREA CLASSIFICATION*; emergency power and lighting requirements are discussed in § 9.1.7, *Emergency Power and Lighting*.

Recommendations for the design and installation of power generators electric motors, transformers, motor control centers and switchgear, distribution systems, lighting, and DC power supplies are addressed in API RP 14F.[61] FLAIM asks if platform electrical systems are in general compliance with the provisions of this recommended practice. FLAIM also asks about the general reliability of power and control systems on the platform, and if there has been any past history of systems failures during emergencies, personnel injuries from electrical shock, or fires involving electrical equipment.

In addition, FLAIM asks about how power and control circuits have been routed throughout the platform and protected from fire and blast damage. FLAIM seeks to assess whether critically important power and control circuits that may be required to operate during an emergency are properly safeguard. Single-point failure scenarios are sought out, such as home-runs to the control room; weak-links in both monitoring and control circuits and power circuits are asked to be identified and appropriate mitigation measures are addressed.

Platforms using cable trays may also be vulnerable to the danger for fire spread along grouped configurations of cables that are insulated and/or jacketed with thermoplastic materials, such as polyvinyl chloride (PVC), neoprene and Hypalon®. Once ignited, grouped cables can rapidly spread fire along cable tray runs, especially where vertical runs are made between deck levels. Melting thermoplastic behaves much as a flammable liquid when burning, and can drip burning droplets of plastic to areas below overhead tray runs, or to lower trays in stacked arrangements. Thermosetting materials that char rather than melt do not exhibit "rain-down" characteristics; nevertheless, these materials too can vigorously propagate fire along cable pathways. Most cable fires emit toxic combustion byproducts such as acid gases as well as very dense smoke, making fire -fighting difficult and increasing the risk to lifesafety.

FLAIM asks if power and control circuits are metal clad (MC) type (armored) cables with a PVC or similar jacketing material, laid in grouped configurations in cable trays. Further, FLAIM asks if protection for these cables has been provided, either using fire resistive coatings, coverings, or fire sprinklers.

5.3.5 Compressed Air System -- Explosion Risks

Compressed air systems present a potential explosion risk if discharge piping becomes contaminated with conventional lubricating oils. This is especially a concern on platforms that utilize air starting systems for large ICEs, such as those typically employed for driving reciprocating gas compressors. Occasionally lubricating oils may bypass air injection distributor check valves and enter the air header, or made by carried-over from the air compressor's lubrication system. Air system explosions can be very violent and produce extensive damage. Their cause was first researched[62] in the mid 1950's and today such incidents are rare.

The risk of air line explosions can be largely eliminated by using noncombustible (fire resistant) synthetic lubricating oils instead of conventional combustible lubricants in both ICE air starting compressors as well as in the engine. This is also recommended for utility/instrument air compressors in high pressure service. FLAIM asks if fire resistant lubricants are used in platform air compressors and air starting systems.

5.4 *THERMAL ROBUSTNESS OF STRUCTURE*

Structural design factors that influence a platform's thermal robustness, i.e., a platform's inherent ability to resist thermal impact are important to understanding how quickly failure may occur.[63] Many conventional platform designs employ relatively lightweight structural members with high slenderness ratios and with corresponding low values of thermal inertia. Such structural elements will rapidly increase in temperature when exposed to the high heat fluxes that can be anticipated in hydrocarbon fueled fires. Once heated above 500°C, steel strength and stiffness (Young's Modulus) rapidly declines; additional thermally induced strains and deformation can quickly exceed design limits. Highly stressed braces and cords can fail in a matter of a few minutes.

Redundant structural members in highly indeterminate systems are often times not *thermally redundant* since their close proximity may subject them to simultaneous fire exposure. Even relatively small LOC events may result in fires of large surface areas and of sufficient duration to lead to structural failure of highly stressed members that are not otherwise protected by fireproofing or water sprays. Conversely, some determinant structures that utilize heavy structural elements characterized by high thermal mass may provide greater thermal robustness than highly redundant multiple load path structures that are not otherwise protected from fire.

Passive fire protection is further addressed in § 9.5, *Thermal Robustness and Passive Fire Protection Systems*

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[1] Some of the data relevant to VESA risk factors are collected in Appendices other than Appendix B3

[2] Incidents of sulfide stress cracking of pressure vessels in wet H_2S service indicate that age is not an important variable. Vessels of all service-lives ranging from less than 2 to greater than 40 years have been founded cracked. Refer to Buchheim, G.M, *Wet H_2S Cracking-Inspection and Repair/Replacement Strategies*, NACE Paper MC-90-80, Exxon Research and Engineering Company, May, 1990, pp. 1-7

[3] Visser, R.C., *Introductory Study to Develop the Methodology for Safety Assessments of Offshore Production Facilities*, prepared for MMS by Belmar Engineering, Redondo Beach, CA, August, 1992. p. 6

[4] Ibid.

[5] Factory Mutual Loss Prevention Data Sheet 7-95, Compressors, Fire and Explosion Hazards, Factory Mutual Research Corporation, Norwood, MA, March 1970, p.3

[6] Geary, C, et al., Design and Operation of the World's Highest Pressure Gas Injection Centrifugal Compressors, OTC Paper Number 2485, Offshore Technology Conference, Dallas, Texas, 1976

[7] American Petroleum Institute Recommended Practice 14C (RP 14C), *Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms*, Fourth Edition, September 1, 1986, p. 60

[8] Factory Mutual Loss Prevention Data Sheet 7-95, op. cit., p. 3

[9] Gale, Jr., W.E., and Keolanui, G., *Report to API Firesafety Engineering Subcommittee on The Explosion of a Centrifugal Compressor's Lube Oil Reservoir*, presented at the 1978 spring meeting of the API Committee on Safety and Fire Protection, Bond Court Hotel, Cleveland, Ohio, April 4-7, 1978

[10] Meyer, C.W., *Fire Detection and Suppression in Natural Gas Pipeline Compressor Stations*, Paper # 87-GT-103, American Society of mechanical Engineers, presented at the Gas Turbine Conference and Exhibition, Anaheim CA, May 31-June 4, 1987

[11] API RP 7C-11F, Recommended Practice for Installation, Maintenance, and Operation of Internal-Combustion Engines, American Petroleum Institute, Fourth Edition, April 1981, Reaffirmed October 1988

[12] *Recommendations for the Protection of Diesel Engines Operating in Hazardous Areas*, Oil Company Materials Association (undated)

[13] U.S. Code of Federal Regulations, 30CFR Ch. II (7-1-92 Edition), Subchapter B, Part 250, *Oil and Gas and Sulfur Operations in the Outer Continental Shelf*, §250.123, (5) Engines, p. 235

[14] Based on personal observation, the problem of stray arcing may be so pronounced so as to be audible even above the high levels background noise of operating compressors, e.g., one may be able to actually hear the sound of electrical arcs jumping the spark gap. Visual verification can be made at night by simply turning off the area lighting and watching for the blue-white sparks as they discharge from ignition wiring to adjacent surfaces. The extent to which this problem may presently exist offshore is unknown, and may vary between operating companies as well as with system age.

[15] API Publication 2216, *Ignition Risk of Hot Surfaces in Open Air*, American Petroleum Institute, Second Edition, December, 1990

[16] National Fire Protection Association, NFPA No. 70, National Electrical Code (NEC), 1990, Article 500.

[17] National Fire Protection Association, NFPA No. 496, Purged and Pressurized Enclosures for Electrical Equipment, 1993

[18] American Petroleum Institute, Recommended Practice 14F (RP 14F), Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms, , Third Edition, September, 1991

[19] API RP 14C, 1986, op. cit., see Figure A6.1, Recommended Safety Devices --Typical Fired Vessel (Natural Draft Heater-Treater), p. 47

[20] Visser, R.C., op. cit., p. 14

[21] A.C. Porter, Jr., *Safe heating is necessary*, Offshore Magazine, January, 1973, pp. 40-43

[22] personal correspondence from W. Gale, Jr. to M. Hilderbrand, American Petroleum Institute, Secretary of Committee on Safety and Fire Protection, Feb. 4, 1983; also see Oil Insurance Association/ Industrial Risk Insurers Bulletin # 501, Fired Heaters, Loss Causes and Guidelines for Safe Design and Operation, 1971, p.2

[23] *Safety Guidelines for Offshore Process Heating*, ARCO Oil and Gas Company Fired Heater Task Force report (undated), received under cover letter dated July 6, 1981 by Bechtel Petroleum (company proprietary information, restricted distribution)

[24] M. Huval, *Use piped heat for platform safety*, The Oil and Gas Journal, February 25, 1974, pp. 47-52;

[25] A.C. Porter, Jr., *Safe heating is necessary*, Offshore Magazine, January, 1973, pp. 40-43

[26] API Recommended Practice for Classification of Locations for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms, America Petroleum Institute Recommended Practice 500B, Third Edition, October, 1, 1987, p.7

[27] Visser, R.C., op. cit.

[28] American Petroleum Institute, API Standard 650 (STD 650), Welded Steel Tanks for Oil Storage, 1993

[29] *Aboveground Storage Tank Incident Information Project*, Prepared for American Petroleum Institute by Events Analysis, Inc. Oakton, VA., Report P8826, December 20, 1988

[30] White, R., and Ehmke, E, Materials Selection for Refineries and Associated Facilities, (prepublished manuscript presented to W. Gale by R. White), January 1990, p.5-2

[31] API RP 2350, Overfill Protection for Petroleum Storage Tanks, American Petroleum Institute, First Edition, March, 1987

[32] Atmospheric Storage Tank Study for Oil and Petrochemical Industries, Technical and Safety Committee, Singapore, Technica, Ltd., London, April, 1990, p.21 (available c/o Mobil Oil Singapore Pte, Ltd., 18 pioneer Road, Singapore, 2262, Attn.: Mr. Stephen Phong)

[33] Buchheim, G.M., Wet H_2S Cracking -- Inspection data and Repair/Replacement Strategies, National Petroleum Refiners Association Paper No. MC-90-80, presented at the Refinery and Petrochemical Plant Maintenance Conference, San Antonio, May, 1990, pp. 1-6

[34] The alternative rules of Section 6 are intended for services that may be regulated under safety, spill, emission, or transportation controls by the U.S. Coast Guard and the Mineral Management Service

[35] American Petroleum Institute, API 510, *Pressure Vessel Inspection Code, Maintenance Inspection, Rating, Repair, and Alteration*, Seventh Edition, March, 1992, p. 11

[36] American Petroleum Institute, API RP 521, Guide for Pressure-Relieving and Depressuring Systems, American Petroleum Institute, Second Edition, September, 1982

[37] *Petroleum Refinery Piping*, ANSI B31.3, American National Standards Institute, 1992

[38] American Petroleum Institute Recommended Practice 14E (RP 14E), Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, American Petroleum Institute, Fifth Edition, October, 1991, p.9

[39] White, R., and Ehmke, E, op. cit., Materials Selection for Refineries and Associated Facilities

[40] Buchheim, G.M., op. cit., *Wet H2S Cracking -- Inspection and Repair/Replacement Strategies*, p.7

41 API RP-14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems* (RP 14E), American Petroleum Institute, Fifth Edition, October 1, 1991, p. 31

42 American Petroleum Institute Standard No. 607, *Fire Test for Soft-Seated Quarter Turn Valves*, American Petroleum Institute, Third Edition, November, 1985

43 The use of soft sealing elastomeric materials for retention of hydrocarbons has been a long-time source of concern in the event of fire. In recent years commercial manufacturers have begun to offer new fire resistant gasketing materials for use in grooved piping systems and fire resistive compression type couplings. Careful consideration of fire test results and test procedures is required to assess the relative risk of fire vulnerability of these sealing materials. For additional information, refer to Patterson, B.H., *Fire Testing for Grooved Piping Systems*, API Committee on Safety and Fire Protection Technical Paper # 2327, presented at the fall meeting of the COSFP, Ft. Lauderdale, FL, September 16-18, 1986.

44 API *Specification for Fire Test of End Connections* (SPEC 6FB), American Petroleum Institute, Second Edition, April 1, 1992

45 API Bulletin 6F1, *Fire Resistance of API/ANSI End Connections*, American Petroleum Institute, First Edition, November, 1, 1987

46 API Bulletin 6F2, *Improved Fire Resistivity of API Connections*, American Petroleum Institute, First Edition, November 1, 1987,

47 API RP 14E-1991, Table 71, *Minimum Extent of Radiographic Weld Examination for Carbon Steel Material*, American Petroleum Institute, p. 45

48 API SPEC 6A, Specification *for Wellhead and Christmas Tree Equipment*, American Petroleum Institute, Sixteenth Edition, October 1, 1989, p. 6

49 Ibid., pp. 128-129; *Close Proximity* also includes any wellhead located within 150 feet of an open flame or fired equipment

50 API Specification for Fire Test for Valves (SPEC 6FA), First Edition, May 1, 1985, Reaffirmed May 1, 1990, and API Specification for Fire Test of End Connections (SPEC 6FB), Second Edition, April 1, 1992, American Petroleum Institute

51 *Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service* (SPEC 14D), American Petroleum Institute, Eight Edition, June 1, 1991, p.5

52 *Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore* (RP 14H), American Petroleum Institute, Third Edition, August 1, 1991

53 U.S. Code of Federal Regulation, 30CFR §250.124, (a) (4), July 1, 1992 edition, p.237

54 Ibid., 30CFR §250.123, (b) (4), July 1, 1992 edition, p.234

55 Ibid., 30CFR §250.121, July 1, 1992, Subsurface safety devices

56 API Specification 14A (SPEC 14A), *Specification for Subsurface Safety Valve Equipment*, American Petroleum Institute, Seventh Edition, January 1, 1988, p.5

57 API RP 14B, *Recommended Practice for Design Installation, Repair, and Operation of Subsurface Safety Valve Systems* (RP 14B), American Petroleum Institute, Third Edition, January 1, 1990 and Supplement 1, January 1, 1993

58 U.S. Code of Federal Regulations, op. cit., 30CFR §250.124, (a) (1), July 1, 1992 edition, p.237

59 Ibid., 30CFR §250.123, (b) (4), July 1, 1992 edition, p.234; SSVs are designed to close before and open after SSSVs in order to limit erosion of the SSSV's valve trim, since changing a SSSV requires a wire line operation which is both more costly and presents more risk to the platform than changing out a SSV. See API RP 14B-1990, §2.3.i.4. for more information.

60 Cullen, The Hon. Lord, The Public Inquiry into the Piper Alpha Disaster, U.K. Department of Energy, vols. I & II, HMSO Publications Centre, London, November, 1990

61 API RP 14F, *Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms* (RP 14F), American Petroleum Institute, Third Edition, September 1, 1991

62 Ridgway, R., *The Mechanism of Explosions in Starting Air Lines*, Petroleum Refiner, Vol. 37, N0. 6, June, 1958, pp. 171- 174

63 Bea, R., Williamson, R., Gale, Jr., W., *Structural Design for Fires on Offshore Platforms*, , OCS Study MMS 91-0057, Minerals Management Service, Technology Assessment and Research Program for Offshore Minerals Operations, 1991 Report, pp. 111-115

Chapter 6

LAYOUT AND CONFIGURATION ASSESSMENT (LACA)

Offshore platforms are especially vulnerable to an escalation fire scenario due to the necessarily close spacing of high-pressured hydrocarbon containing equipment, e.g. potential release sources, and potential ignition sources. Any LOC event or incipient fire that is not quickly detected and controlled is of great concern; especially on those platforms with accommodation facilities where life safety is at issue. In general, it can be said that an offshore platform has all of the fire safety concerns found in a typical onshore petroleum production facility, plus several additional factors that greatly increase the risk of escalation and personnel injury.

LACA risk factors account for the relative increased risk of certain design features, or lack thereof, that can significantly increase a platform's susceptibility to escalation.

6.1 *GENERAL ARRANGEMENT CONSIDERATIONS*

There are several determining factors that affect the layout and spacing of new platform designs. Platform layout, configuration and arrangement is primarily determined by the projected field development and economic considerations based on initial well test information and projections. The number of planned production and EOR wells, the drilling (and pre-drilling) program and planned number of drilling rigs, the type of drilling rigs, the reservoir characteristics and anticipated peak production rates, the production fluid characteristics (gas-oil ration -- GOR, viscosity, pour point, corrosivity, and processing factors that determine the process equipment needs, the depth of water in which the platform is located and the means of transporting the produced fluids (amount of onboard storage required, etc.), crew accommodation requirements, etc., are but some of the essential inputs that shape the size, complexity, and configuration of a platform.[1]

The goal of a designer is to arrive at a layout that will provide for safe and efficient operations given the imposed economical and design constraints. In addition, a well planned platform will be designed with provisions to allow for future expansion based on a best-guess prediction of what these needs may be with a high degree of uncertainty.

Spatial arrangement of equipment and arrangement of platform areas are arrived at by determining:

- space needed for operations, e.g., laydown areas, and operating personnel
- space needed for maintenance access, e.g., heat exchanger/fired heater tube pulling, etc.
- space needed for fire fighting activities
- space needed for separation of ignition and fuel sources
- space needed to limit exposure of important items to fire and explosion, e.g., risers, crew quarters, etc.
- space needed for fast and unobstructed egress during emergencies
- and space for future expansion

Providing adequate space for future needs is often difficult to accurately predict during initial planning and engineering stages, and such provisions may be underestimated or even excluded from the planning process. Hence, over a period of years, older production platforms that were initially designed with well thought-out configurations, become congested and overcrowded, such as in the case of New Zealand's first gas condensate platform, Maui Platform A. In the case of Piper Alpha, subsequent modifications to the initial gas processing design caused increased exposure to the accommodations module, contributing to the tragedy.

However, even the best planned and thought-out platform arrangements and configurations cannot fully compensate for fire and life safety risks solely on the basis of spacing, arrangement, and physical separation. The spacing and arrangement that would be required to achieve fire and life safety goals based solely on these parameters is inherently incompatible with the physical/design constraints and operating realities of offshore operations.[2] Hazardous equipment, high risk operations, and high concentrations of personnel that would normally be separated by much greater distances for safety considerations onshore, are necessarily compacted and concentrated into very limited spatial arrangements offshore. Understanding this has two immediate consequences:

1) an "idealized" platform arrangement with regard to optimizing safety is nevertheless very reliant on other design and process safety risk reduction/mitigation measures in order to achieve an acceptable level of operational safety. Spacing and arrangement alone cannot by themselves meet risk management goals. and

2) how platforms are configured and arranged is all-the-more important to the ultimate level of residual or inherent risk under which the platform must operate.

Some may argue that on an offshore platform spacing between various hazards is so limited that it becomes, to a large extent, truly irrelevant to safety within the spacing options under the designers control. For example, in the event of a high pressure gas leak at a pipe flange on an open deck platform, the resulting vapor plume, or, if ignited, fire plume could credibly extend 200-300 feet or more from its source. Therefore, when compared to the amount of space actually available to separate various hazards, the separation of two items by ten feet versus, say twenty-five feet is not truly meaningful from a safety standpoint, but conversely, can be very critical from a planning standpoint.

While there is a certain amount of credibility to this argument, the rational can be carried to an extreme in the pursuit of space optimization. As more and more equipment is "shoe-horned" into the topside configurations to meet current field needs, the relative risks to fire and life safety can be greatly and unwittingly increased. Equipment may be stacked, cantilevered, or otherwise piggy-backed onto and into areas without due regard for how safety is being impacted -- nor how vulnerability to rapid escalation of an initiating event is being increased.

Deficiencies in layout and configuration schemes may result in overall high levels of risk that cannot be fully compensated for by other risk mitigating measures, i.e., risks to life safety from, for example, gas treatment/compression facilities or gas risers that are located too close to or beneath living quarters. Haphazard arrangements that may have evolved in a reactionary manner to production/EOR demands/field development needs may be so inherently flawed that their residual risk levels ought to make them classified as unfit *for purpose*.

Attempts to compensate for "fatally-flawed" design features through the use of bulkheads, compartmentation, fire deluge systems, and similar mitigation schemes can in some cases even serve to further exacerbate rather than ameliorate the safety problem by decreasing ventilation, increasing anticipated blast wave turbulence and overpressures, making access for fire-fighting and escape more difficult, overloading drainage system capacities. For example, using water sprays on vessels to compensate for overloaded pressure relief headers rather than increasing system design capacity places undue reliance on water system reliability and may provide a false sense of security.[3]

FLAIM seeks to examine present-day arrangements and configurations of existing platforms for conformance with criteria compatible with achieving safety management goals. FLAIM attempts to distinguish acceptable trade-off's and compromises from those decisions that were perhaps made in haste or out of a perceived necessity that, in fact, results in an untenable perception of fire and life safety. To do this FLAIM included default spacing and layout criteria to assist in this determination; however, FLAIM does not presuppose to apply this criteria unilaterally without due consideration for other operating factors, platform design features, and operator experience. Therefore FLAIM has been specifically designed to allow the user to determine what constitutes acceptable layout and spacing criteria (and corresponding risk levels) for the particular facilities under review with due consideration to proprietary databases and operating experience.

For example, if an operator deems that a distance of twenty-five feet separation is prudent to maintain between a crew quarters and a gas compression skid, but in no case is less than 15 feet acceptable, FLAIM's algorithm can be adjusted accordingly, recognizing that the acceptable level of risk is the operators responsibility to establish. FLAIM, in turn, will allow operators to demonstrate this determination and its application were performed with due process.

6.2 *TOPSIDES ARRANGEMENTS AND AREAS*

Design practices for topsides layouts that developed during the 1960's and early 1970's were captured and promulgated in an API Recommended Practice that has since been withdrawn due to obsolescence.[4] In its place, API RP 14J includes information on layout and spacing intended to update the practices contained in RP 2G.[5] Both API RP 2G and RP 14J recognize the importance of separating/isolating areas containing potential ignition sources from those handling flammable production fluids. In addition, some types of equipment in which both potential fuel and ignition sources are integral to their operation are recognized as representing unique hazards that may be grouped together and provided with appropriate risk mitigation measures, e.g., engine driven or turbine drive gas compressors.

Ideally, designers seek to maintain as much spacing as possible between potential ignition sources and potential fuel sources. This leads to some general guidelines:

- prevailing winds should be considered in arranging the platform -- open flames and other potential ignition sources should be located upwind of fuel sources whenever possible, e.g., the flare boom should be upwind with the flare plume blowing towards the platform or off to the side.

- equipment handling heavier-than-air vapors should be located at upper deck levels, but without lower level ignition sources. Compressors handling lighter than air gases should be located in the open without overhead head potential ignition sources.

Production platforms are generally arranged in accordance with the following typical functional subdivisions.[6]

6.2.1 The Well Bay (wellhead module or wellhead area(s)) contains the wellheads (Christmas trees) of completed wells, including water/gas injection wells as well as production wells. The wellhead chokes, production & test manifolds and headers may also be located here, or in the production (process) area (see § 6.2.2). The well bay typically contains the highest pressures on the platform and is one of the highest risk areas onboard.[7]

Wellheads should be isolated insofar as possible from all other areas on a platform, especially from potential ignition sources and large sources of fuel release, such as storage tanks. Operational demands require careful consideration of individual wellhead spacing. Wireline operations and workover rigs must be able to operate on any individual wellhead without endangering or requiring the shut-in of adjacent wellheads. In the event of fire in the wellbay, adequate space must be provided to permit personnel access to wellhead control valves, as well as facilitate quick egress for the area. A minimum of two primary paths of egress are normally required from the wellbay. Other design considerations include overhead protection from dropped objects while permitting access for hole re-entry, and designing to promote as much natural ventilation as possible while accommodating needs for fire separations from adjacent process and gas treating areas.

The overriding design consideration in the layout of a wellhead area, however is in direct competition with those goals listed above, e.g., to maximize the number of wellheads within as small as space as possible thereby reducing topside weight, size and overall platform costs. This is a reflection of the same economic realities that led to eventual elimination of auxiliary platforms which were frequently employed in the early days of GOM development, and especially applies to areas where field development costs are exceptionally high due to environmental demands, e.g. deepwater (e.g., Green Canyon Area) and harsh areas such as the North Sea. To user Fraser's[8] words, *the overriding design criteria for wellhead patterns in North Sea platform design has been space...by trying to get a quart into a pint pot two tier systems have been developed.* Or, as Professor Bea is apt to say, *like trying to put 10 pounds of potatoes in a 5 pound sack..*

In the case of a two tier (level) wellhead arrangement used on occasion in the North Sea, Fraser[9] opines that the desire to optimize wellhead spacing as led to a particularly poor design from a safety standpoint. In the event of a fire or explosion in a lower tier wellhead, the upper level wellheads are directly exposed to thermal and blast impacts, not only increasing vulnerability but also making control efforts much more problematic.

Many older GOM platforms are based on relatively simple designs with open single decks or double decks on which wellhead are located in an area, often times along an outboard edge in two or more rows. In the case of two decks, wellheads are normally located on the lower (or cellar) deck. Since wellheads must be accessible to drilling/workover rigs from above, wellheads located on lower decks must be provided with overhead access. Mechanical impact from dropped objects, such as during the installation of blow-out-preventers (BOPs) is a significant potential hazard to wellhead integrity and demands constant vigilance and careful planning during topside crane operations, including service boat deliveries.

FLAIM asks for the number of and spacing between wellheads as an input to LACA. Wellhead pressures and flowrates are identified in LOCA. The suitability of the wellhead design (Christmas tree) for the particular service conditions in accordance with API RP-6A is also assessed in LOCA. FLAIM performs the LACA wellhead computation using a minimum safe spacing criteria between the adjacent wellheads of flowing wells based on 2.5 meters (7.5 feet)[10] of clear space between adjacent Christmas trees (not centerline to centerline). FLAIM also makes judgments or relative risk based on a recommended maximum of 36 flowing production wells in a single contiguous grouping. FLAIM's algorithm considers that each group of 36 wells should be isolated by either a twenty-five foot "dedicated fire-break" separating adjacent groups or an intervening fire/blast wall. Any single group of 36 of less wells should further be restricted to no more that four continuous rows of nine wells or, in the case of a three of two rows, this criteria results in twelve or eighteen wellheads in succession.

For wellheads operating above 5000 psia, FLAIM considers that the maximum number of wells in a single group should be limited to 24, again with no more that four rows. Hence, this would result in either four rows of six wells, three rows of eight wells or two rows of twelve wells.

Artificially assisted (dead crude) wells that rely on downhole hydraulic or electric pumps are recognized to pose less risk than flowing (live crude) wells, including natural flowing wells and those flowing due to EOR efforts and may be excluded from the grouping limitations suggested above.

FLAIM uses the above criteria to assess relative wellbay risk on a comparative basis, and does not presuppose to suggest that other arrangements cannot be safely developed. The user may wish to modify this criteria based on in-house policy, practices and experience in order to arrive at a suitable yardstick for comparative measurements. It should be noted that in this regard, FLAIM's primary goal is to provide the methodology to perform comparative assessments, and to identify situations that have deteriorated (from a risk standpoint) with accepted practice but have not been identified.

6.2.2 The Unfired Process Area: (production or separator module/deck/area) in which the production separators (sometimes slug catchers) are located. There may be a single train or a multiple train processing arrangement, depending on the size and production throughput of the platform. In addition to the production train(s), there is also a test train, which is a smaller version designed to handle the flow from a single well. A typical production module will have two or three stages of separation: the first stage separator is the first (most upstream) to receive production fluids and consequently operates at the highest pressure -- the same pressure as the downsteam setting of the wellhead choke. The second and third stage separators operate at successively lower pressures, enabling more dissolved gas to be liberated from the crude with each stage of treatment .[11]

Production separators are typically the largest pressure vessels located on a platform and their locations are considered high risk areas -- together with the wellbay, usually the highest on a platform. The minimum shell-to-shell spacing between adjacent horizontal production separators is considered by FLAIM to be 3 meters or approximately 10 feet at the closest tangential points, independent of operating conditions.

6.2.3 Gas Compression Area: the gas compressor module is a high risk fire area that differs from the wellbay and production modules by the nature of the hazard. Engine driven and combustion gas turbine driven compressors pose unique risks due to the close coupling of potential ignition sources, e.g., hot surfaces, and potential fuel sources. There are two primary risks in the compressor area: a gas leak and ensuing explosion and/or high velocity jet fire, and, in the case of centrifugal machines, fire/explosions resulting from leaks in the external force-feed lubrication and seal oil-buffer gas systems. Additional risks include process upsets and liquid carryover, surge, mechanical failure at high speed, e.g., fatigue failure of turbine blades, and operator error.

Ideally, the best location for gas compression equipment is on a separate platform from wellhead and production equipment, as well as separate from crew quarters. When gas compressors are located on unitized production platforms, they should preferably be located in the open on the upper deck, downwind from all potential ignition sources and as far away as possible from the well bay and crew quarters. This arrangement, however, is difficult to achieve in practice, and in fact, gas compression facilities can be found on many platforms very near or adjacent to the crew quarters.

When gas compression facilities are enclosed, the risk of gas accumulation is greatly increased. Ignition of released vapor accumulations or gas leaks can result in severe explosion damage and further event escalation. To compensate for this risk, enclosed compressor modules may be only partially enclosed, or if fully enclosed, provide with explosion relief (venting) provisions and well as gas detection systems and high capacity air handling systems to ensure adequate ventilation. Such mitigation measures, however, not only increase reliance on mechanical system integrity and rigorous preventative maintenance programs, but also complicate layout.

The design of explosion relief (blowout) panels require large surface areas for effectiveness, and demand clear space on the enclosure's exterior to ensure personnel safety in the event of their operation. They must be also designed with low inertial properties and have restrictive fastening requirements in order to rapidly relieve internal pressures before destructive levels are reached. Unfortunately, high wind loads and physical obstructions/interferences encountered offshore can limit the effectiveness of such designs (see Risk Reduction Measures Assessment in **Chapter 9**).

FLAIM considers the location of gas compression facilities on the platform in relation to other high risk areas with due regard for risk reduction measures. These include fire, blast, and vapor barriers -- both vertical and horizontal, vapor detection and removal provisions, ignition control measures, operating service conditions and the type of machines employed, depressuring and shutdown capabilities, and fire suppression systems. Refer to § 5.2.2.1.2 for compressor VESA considerations, § 5.2.2.1.3 for internal combustion engine VESA considerations, and ¶ 5.2.2.1.4 for gas turbine VESA considerations.

6.2.4 Power Generation and Utility (POGU) Area: also sometimes referred to as the machinery area is generally considered as being a potential ignition source for escaped vapors and should be separated or otherwise isolated from wellhead and process areas. The POGU area contains the platform's source of electrical energy -- usually either combustion gas driven or engine driven electrical generators. Fuel is limited to the turbine/engine supply lines; SDV's are commonly provided to facilitate remote shutdown of fuel into the area. Other equipment found here included air compressors, hoists, and sometimes the platform fire pumps. A motor control center (MCC)/switch gear room may also be located nearby.

6.2.5 Fired Equipment Area: the fired equipment area is generally characterized as a high fire risk area on most platforms and should be located so as to pose minimal fire exposure risk to adjacent platform equipment areas and arranged so as to facilitate fire-fighting. Fired equipment should be preferably grouped together in a single area on a production platform that is especially designed and located for fire safety. If fired equipment is located in several different places on the platform, ensuring safe operation becomes more difficult, even if all units are designed as protected (low ignition risk) equipment (see § 5.2.2.2).

FLAIM asks if the fired equipment area is located upwind of the wellbay and process areas, as well as accounting for vertical separation between decks. FLAIM generally relies on the spacing recommendations of Section B of API RP 500[12] to assess the adequacy of electrical area classification. However, the spacing provided between fired equipment and hydrocarbon handling areas is based on **Table 6-1** below. FLAIM utilizes criteria adopted in NFPA 497A[13] for assessing spacing between possible ignition sources and fuel sources based on actual operating conditions, e.g., pressure, flow, and volume. FLAIM's algorithm has been programmed to calculate LACA risk factors using the following criteria:

Table 6-1

Criteria Used Assessing Relative Magnitudes of Process Variables for Equipment and Piping Handling Flammable Liquids or Gases[14]

Process Variable	Units	Small --Low	Moderate	Large--High
Capacity (V)	Barrels	V < 100	100 < V < 600	600 < V
Pressure (P)	psig	P < 100[15]	100 < P < 500	500 < P
Flow Rate (Q)	bpd (gpm)	Q < 3500 (Q < 102)	3500 < Q < 17,000 (102 < Q < 496)	17,000 < Q (496 < Q)
Basic Spacing	feet	15	25	50

6.2.6 Petroleum Storage, Metering and Shipping Areas & Pig Traps: storage of produced crude oil, condensate (natural gas liquids), methanol, glycol, aviation fuels, and other flammable liquids in significant quantities on production platforms has been identified as a significant risk contributor impacting both fire and life safety. The risk depends on several factors including the normal onboard inventory, the storage methods employed (atmospheric, pressurized, blanketed, etc.), the spacing, location and condition of the storage containers, and the risk reduction measures provided.

FLAIM's LACA component seeks to establish where flammable liquid storage is located and how it is configured. Free-standing atmospheric storage tanks located on the top deck are considered to have the highest potential vulnerability to damage from impact, dropped objects, seismic events, etc. as well as represent a significant fire exposure potential from operational LOC events due to overfill/overflow, etc. Storage tanks that are integral to the jacket design (interstitial tanks framed by structural members of the jacket) afford greater physical protection and are considered to present a lower LOC risk than free standing tanks, given equal levels of preventative maintenance, inspection, and safety instrumentation. Interstitial tanks are normally located in the lower deck level of the structure and consequently overfills/spills may also present a lower risk of spreading to other areas.

Crude oil metering and shipping facilities may vary considerably on older platforms. Lease Automatic Custody Transfer (LACT) units and motor driven centrifugal pumps are the frequently used to send crude to shore via pipeline. Often times these are located on the lower deck level and adjacent to pig launcher/receiving facilities. The primary hazards associated with this equipment during normal operations are loss of containment events due to pump seal failures, drains and vents, or human error. Pigging operations involving pipelines to shore or between platforms are highly dependent on human actions and therefore prone to human error events. During pigging operations, releases of crude oil and gas may be anticipated to occur to some extent, and proper operating procedures and safeguards must be maintained to avoid incidents. Pig launchers/receivers (pig traps) should be located in open, freely ventilated areas located downwind of potential ignition sources, such as the flare.

6.2.7 Pipeline Risers: the location of pipeline risers are generally determined early in the structural design of the jacket by the placement of "J-tubes." Risers should be located so as to be protected from physical damage -- both on the sea bottom from dragging anchors and as they ascend along the jacket structure from impact service vessel impact, cargo off loading handling, dropped objects, etc. Physical damage and corrosion are the two most serious concerns leading to loss of integrity and an LOC incident. As was tragically illustrated in the Piper Alpha (July, 1988) and ARCO South Pass Block 60 Baker (March, 1989) platform incidents, riser damage leading to uncontrolled flow is a potentially high consequence event of the highest order. Older platforms with high pressure oil and gas risers which are not equipped with underwater safety shutoff valves are subject to uncontrolled flow of fuel should the riser fail below the last surface safety shutoff valve.

FLAIM seeks to identify the number and location of platform risers and their relationship to key platform areas. LACA assesses whether or not risers are located adjacent to or below the crew quarters as well as the location of the first platform safety shutoff valve in relation to sea-level.

6.2.8 Flare Boom/Stack: the platform flare is a potential source of ignition for large vapor clouds released from high pressure wellheads, risers, or process equipment. Normally, the boom/stack of atmospheric flares is located at sufficient distance/elevation from the upper deck to limit incident radiant heat flux levels so as to limit the risk of ignition of most all except catastrophic size accidental gas releases. The orientation of the flareboom/stack should take into account the prevailing winds; flare stacks should preferably be located on the windward[16] side of the deck, and cantilevered booms should extend off to one side of the leading (windward) edge of the platform.
Elevated flares that are located directly upwind or above the upper deck are also a potential fire hazard. In the event of liquid carryover from the knock-out vessel (scrubber), burning hydrocarbon liquids may be expelled from the flare tip and "rain-down" onto the platform's upper deck, helideck, and or quarters structure. Vent stacks are also subject to the same scenario. For this reason, upstream liquid knock-out vessels in relief systems must be adequately sized, properly instrumented/alarmed, and frequently inspected and maintained.

6.2.9 Control Room/Radio Room: the relevant importance of the control room/radio room to impairment of the safety shutdown function should be commensurate with both the level of integrity/security provided for, as well as the location of these areas. Moreover, from a life safety standpoint, normally manned control facilities require protection from potential blast, vapor cloud, and fire exposure hazards, e.g., treated with the same degree of regard as the crew quarters. Many older platforms have process schemes based on local pneumatic control and do not require elaborate centralized control facilities. Newer designs using distributed control systems (DCS) and/or programmable logic controllers for process control may still rely on simple pneumatic and hydraulic shutdown systems that are designed for fail-safe operation.

FLAIM seeks to distinguish between those designs that rely on control room serviceability to effect safe platform shutdown from those that do not, and to assess the degree of dependency on which process control/control room integrity is linked to the safety shutdown function. For those situations where there is a close coupling, FLAIM assesses the control room's relative degree of exposure to hazards by virtue of its location, as well as exposure/protection of data highways/instrumentation and control cable runs (home runs). Radio rooms that are vital to maintaining the safety function are similarly evaluated. SCADA[17] systems that may be utilized for decision making by off-platform personnel during emergency situations as well as other critically important communication links used, for example, to initiate helicopter rescue operations, are identified and assessed accordingly.

6.2.10 Accommodation Modules/Crew Quarters: FLAIM seeks to identify those platforms that pose inherently high life safety risks to onboard personnel by virtue of the crew quarters location. FLAIM uses a minimum separation distance of 75 feet as a comparative basis to evaluate relative exposure hazards to the crew quarters from high pressure hydrocarbon handling equipment, e.g., the wellhead, production, and gas compression areas. FLAIM also accounts for risk mitigation measures employed to offset more restrictive spacing arrangements. This is further addressed in Chapter 8, Life Safety Assessment.

6.2.11 Helideck/Aviation Refueling/Fuel Storage Area: If the platform has a helideck that is provided with refueling facilities for incoming aircraft, FLAIM seeks to identify the location of onboard aviation fuel storage facilities with regard to the potential risk of an LOC event due to overfill, physical damage, and fire exposure.

6.2.12 Egress Paths/Escape Stations: The relative degree of congestion of platform equipment areas is important from both a fire-fighting standpoint and a life safety standpoint. FLAIM seeks to assess deficiencies in platform layouts that may have been a shortcoming in the initial design or that have developed during the course of platform modifications and have heretofore gone unrecognized. This is further addressed in Chapter 8, Life Safety Assessment.

6.3 *AREA CLASSIFICATION*

Electrical area classification, as prescribed by the National Electrical Code (NEC)[18] provides the basis for the selection of electrical equipment relevant to the extent to which flammable concentrations of vapors may be present in a particular area or location. API Recommended Practice 500B[19] interprets and applies the basis principles of the NEC to offshore platforms.

FLAIM seeks to determine the extent to which platform electrical area classification is consistent with the basis tenets of RP 500B, e.g., if the location and extent of classified and unclassified areas is indicative of present platform operating conditions. Many offshore facilities must depend on the provision of vapor-tight barriers and positive pressure ventilation systems, rather than rely solely on spacing and layout, in order to achieve non hazardous (unclassified) areas in which non classified electrical equipment may be operated. FLAIM does not perform a detailed analysis for electrical area classification assessment; such a study however may be warranted.

FLAIM assesses if:

1) platform documentation includes an up-to-date electrical area classification plan,
2) the extent of classified and unclassified areas are shown -- both in plan view and in elevation,
3) Class I locations as shown on the plan generally conform with those areas on the platform in which flammable concentrations of vapor may be present during normal or abnormal operating conditions, including consideration of required routine maintenance and operating activities, and
4) electrical equipment and wiring in those areas conforms with the requirements for classified locations and is well maintained and proper working order.

FLAIM recognizes that a common problem on older platforms stems from the addition of hydrocarbon handling equipment in areas that may impact the extent of classification boundaries. This is more of a concern on open decks where classification boundaries have been determined based solely on separation distance (spacing), but can also have less obvious design implications such as compromising the location of safe ventilation air intakes for unclassified area pressurization. Pressurizing air must be taken from a location deemed to be safe from the presence of flammable vapors under both normal and upset conditions. Exhaust stacks from combustion gas turbines, internal combustion engines, etc., and vent stacks from maintenance vent headers must be considered as well to avoid inlet air contamination. The preferred location for intake ducts inlets is at an elevated position on the upwind side of the platform.

Some platforms may have several local electrical switchgear rooms/motor control centers located adjacent to or in process areas. In this event, the risk of ignition of escaped flammable vapors may be significantly increased by reason of electrical ignition source proximity. Switchgear rooms/enclosures and MCCs in which unclassified electrical equipment is located should be pressurized/purged to ensure escaped vapors from nearby process equipment cannot enter the area. This can be accomplished by maintaining a positive pressure of at least 0.1 inch of water column within the room and an air velocity of at least 60 ft./minute out of the room when all doors and windows (if any) are open; however the pressure and velocity requirements need not be met simultaneously.

There are three different types of purging, depending on the electrical area classification, as described by NFPA 496.[20] The design most frequently encountered offshore is Type Z, in which a room or enclosure containing ordinary (spark-producing) electrical equipment is placed in a Class I, Division 2 location. In the GOM, the use of humid, salt-laden air for purging can accelerate corrosion of electrical equipment and decrease system reliability. Consequently, purged air may first have to be dehydrated or otherwise treated to reduce this problem. Enclosures can be provided with inert gas or dry instrument air from platform utility systems; however, electrical equipment and control rooms require separate (individual) air handling and treating systems for purging.

The problems of system maintenance and reliability are compounded if several small switchgear/motor control rooms are located in various places on a platform. In addition, ensuring air intakes are located in a manner such that the risk of flammable vapors becoming inducted into the air inlet becomes more problematic. It is, in general, not uncommon to find ventilation inlet ducts located too close to potential sources of vapor release, and undue reliance placed on the response of combustible gas detectors to effect shutdown prior to ignition. Unfortunately, the response time of most commercially available combustible gas detectors cannot initiate system shutdown fast enough to always prevent ignition in the event of a large release. Gas can be quickly drawn into electrical equipment rooms via the air handling system, ignite, and flash back to the vapor source with devastating consequences within a matter of seconds.

Another commonly encountered problem on older platforms is failure to adequately maintain classified electrical equipment. Explosion-proof (EP) equipment cannot properly function if cover plates are missing, not fully engaged, missing securing bolts, or otherwise deficient. This is a matter of particular concern offshore not only due to the close spacing of equipment, but also due to the inherent problem of condensation and moisture accumulation within EP enclosures, leading to high maintenance and inspection demands.

Maintenance of air handling/treating equipment designed to pressurized/purge control and electrical rooms has already been mentioned. It is often the case that the ventilation fans have failed, leading operating personnel to prop-open room doors in order to control room temperatures. Obviously, this is a type of cognitive-based human error with extremely severe potential consequences that FLAIM seeks to identify. In general, FLAIM seeks to determine the extent to which platform electrical systems are out of compliance with recommended practices due to design and maintenance-related problems, as well as assess management's awareness of their safety implications.

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[1] Bea, R.G., Construction of Harbor Coastal, and Offshore Structures, *Construction of Offshore Platforms*, (Class Notes), CE 267C, University of California, Berkeley, Fall Semester, 1988

[2] For example, see American Petroleum Institute, Recommended Practice RP 14J (RP 14), *Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities*, First Edition, (DRAFT), October, 1992, p. 110, (Appendix B), "Analysis of Example Layouts;" limitations in deck area, equipment spacing and arrangement always requires some degree of compromise -- no offshore design can be free of disadvantages, e.g., increased risk to fire and life safety as compared to onshore operations in which the inherent level of safety can be realized due to greater design freedom with regard to spacing and layout. [It is noted that the referenced API Recommended Practice (RP 14J) is a draft version pending final approval, and its citation should not be construed to represent API's final position on this matter].

[3] American Petroleum Institute Recommended Practice 520 (RP 520), *Recommended Practice for the Design and Installation of Pressure-Relieving Systems in Refineries*, Part I -- Design, American Petroleum Institute, Fourth Edition, 1976, pp. 15-16; and API RP 521, Guide for Pressure-Relieving and Depressuring Systems, American Petroleum Institute, Second Edition, September, 1982, p. 15

[4] American Petroleum Institute Recommended Practice 2G (RP 2G), *Recommended Practice for Production Facilities on Offshore Structures*, First Edition, January, 1974

[5] API RP 14J (DRAFT), op. cit., Figures B1, B2, and B3, Oil Production Facility, 2-Level Platform, pp. 112-117]

[6] Ibid., Table 5.2, Equipment Categories, p. 57

[7] Ibid., p. 49

[8] Fraser, K., *The Design of Well Control Systems and Production Completions to Limit Fire and Explosion Damage on Offshore Platforms*, Fire Safety Engineering -- Proceedings of the 2nd International Conference, BHRA, The Fluid Engineering Centre, Canfield, Bedford, U.K., 1989, pp. 55-62

[9] Ibid.

[10] This distance is considered to be the minimum free clearance required for safe access by some operators, regardless of wellhead conditions. The wellheads of producing wells that are closer than 2.5 meters to a well being drilled should be required to be shut-in by closing the downhole safety valve. For example, *Safe Operating Practices, Exploration and Production*, Shell Internationale Petroleum Maatschappij N.V. -- The Hague, Report EP-43435, April, 1972, p. 67, ¶ (f), (company proprietary information -- restricted distribution)

[11] American Petroleum Institute Recommended Practice 14E (RP 14E), *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*, Fifth Edition, October, 1991, p.39, see Figure 5.2

[12] American Petroleum Institute Recommended Practice 500 (RP 500), *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities*, First Edition, June, 1991.

[13] National Fire Protection Association, NFPA 497A, *Classification of Class I Hazardous Locations for Electrical Installations in Chemical Plants*, 1992

[14] Source: based on Table 3-2, NFPA 497A, *Recommended Practice for Classification of Class I Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas*, National Fire Protection Association, 1986 Edition, p. 9. The basic spacing is premised on open decks that are freely ventilated; known ignition sources and process equipment should never be located within the same enclosed area. The presence of highly volatile liquids (HVL's) in significant quantities may substantially increase the basic spacing criteria needed to ensure safety. Known ignition sources, such as open flames, should be generally avoided, and in all cases located no closer than 50 feet upwind from potential sources of hydrocarbons unless engineered as a protected system.

[15] Some operating companies may elect to use higher pressure criteria. For example, 275 psig is used in Section C of API RP 500 as a discriminator for some liquid hydrocarbon services.

[16] *windward side* is used here to mean the upwind side of the platform -- this is sometimes also referred to as the leeward of the platform by sailors, e.g., the side of a landmass facing the lee side (down-wind side) of a ship to which the wind is blowing towards.

[17] Supervisory Control and Data Acquisition systems

[18] National Fire Protection Association Standard No. 70 (NFPA 70-1987), National Electrical Code, Article 500; also see Sharm, P., The National Electrical Code 1987 Handbook, National Fire Protection Association, 1986, pp. 659-704

[19] American Petroleum Institute, *Recommended Practice for Classification of Locations for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms*, (RP 500B), Third Edition, October 1, 1987; Note that API RP 500, op. cit., as replaced RP 500B but retains much of its contents.

[20] National Fire Protection Association, *Standard for Purged and Pressurized Enclosures for Electrical Equipment in Hazardous (Classified) Locations*, NFPA 496 - 1992.

Chapter 7

OPERATIONAL/HUMAN FACTORS ASSESSMENT (OHFA)

Shortly after the Piper Alpha accident, the U.S. OCS experienced the loss of a production platform from a fire which also took seven lives.[1, 2] Human error was the direct cause for an uncontrolled release of hydrocarbons during a repair operation involving an 18 inch diameter gas riser.

Over 80% of high consequence offshore accidents are attributable to some form of human error, and 80% of these can be related to operational aspects of platform activities, e.g., 64% of high consequence accidents result from operational error.[3]

FLAIM considers that errors involving operational activities is the single most important class of risk contributors leading to platform fires, explosions, and loss of life. Many factors contribute to this problem, as identified by Bea and Moore,[4] including fundamental deficiencies in organizational aspects of the management structure. The Marine Board lists "management attitude" together with training and communication as key factors in improving operational safety.[5] FLAIM addresses issues of management attitude and organizational aspects of "safety culture" in **Chapter 10,** (SAMSA).

Chapter 7 focuses on what is termed "front-line" operational aspects of platform activities that directly contribute to increased risk levels. Changes in operations may routinely occur, such as periodic workovers, wireline operations or other downhole and topsides activities that, in turn, temporarily increase the overall level of risk on the platform until the job is completed. As discussed in § 10.4, the overall level of platform risk at a particular point in time, e.g., real-time risk or *effective risk*, $\mathbf{R}_\tau$, at time τ, varies from a normalized baseline risk, $\mathbf{R}_b$, or residual risk, in accordance with nature of the change taking place. Changes of a temporal nature, such as conducting a high risk activity for a finite time period, will cause an aberration of the level of effective risk, $\mathbf{R}_\tau$.

In Operational/Human Factors Assessment (OHFA), FLAIM seeks to identify those normally encountered production activities which may involve either an inordinate reliance/dependence on human judgment to avoid serious consequences (direct-link couplings), or activities in which the risk of error is compounded by the complexity or multiplicity of the tasks involved, e.g., multiple simultaneous operations such as drilling, producing and maintenance involving hot work or startup of equipment. Swain[6] uses the term Error-Likely Situations (ELS) to generally describe such work activities, and further identifies a special subclass of ELSs as Accident-Prone Situations (APS) which deal with human error-caused accidents.

7.1 *MAINTENANCE AND REPAIR WORK (MARW)*

Several activities are considered under this grouping. Most production platform will be exposed to one or more of these activities during normal operations, e.g., without curtailment of production, except for preplanned turnarounds or major retrofits. Activities include:

- major renovations/additions
- turnarounds
- routine maintenance/repair work involving equipment entry, line-breaking, and hotwork
- pigging/scrapper work
- downhole wireline work such as removing and testing storm chokes
- workover operations
- specialty work, such as pipeline riser retrofits/additions, control system modifications necessitating temporary bypass of safety shut-down functions, fire protection system work causing temporary impairment of the protection systems

Often times these activities involve "line-entry" or "vessel-entry" procedures whereby the risk of an LOC event is increased. Normal process control elements, pressure relief valves, emergency shut down valves, and other control and safety provisions may be placed in a bypass mode or be removed from the system, thereby increasing the potential vulnerability to an initiating event. Hot work involving welding, cutting, grinding, etc. is also commonly included, resulting in increased ignition risk.

During MARW, reliance on human intervention and judgment is greatly increased over that required for normal operations -- both from a preventative and a response standpoint. Simply put, more things can go wrong, and there is a greater dependency on worker judgment to make the correct decisions. However, there is also a greater risk of error during such activities, especially so when non-routine operations are involved, job complexities are increased, and work crews may be diverse and unfamiliar with the facilities or inadequately trained in the particular operations taking place.

The criticality of any particular MARW activity has been distinguished by Bea and Moore[7] into four major categories:

- *process critical*
- *process non-critical*
- *non-process critical*
- *non-process non-critical*

Process critical operations are considered to be those activities that involve vessel and/or line entry into hydrocarbon handling systems and equipment, e.g., operations posing an immediate risk of loss of containment. This includes all topsides process systems in which crude oil, natural gas, natural gas liquids (condensate) liquefied petroleum gases, and imported flammable liquids (methanol, glycol, aviation gasoline, etc.) are either processed, treated or otherwise handled/stored. In FLAIM, process critical operations as a group is further subdivided into three subgroups:

- process critical - HIGH (pressure exceeds 500 psig)
- process critical - MODERATE (pressure above 100 but less than 500 psig)
- process critical - LOW (pressure 100 psig or less)

Process non-critical operations are considered in FLAIM to involve equipment and systems that handle non-volatile, combustible liquids (flash points above 140°F) at or near atmospheric pressure, such as fuel oil, diesel fuel, and lubricants.[8]

Non-process critical operations are those activities that impact a platform's ability to respond to an LOC event, including fire and explosion, or that increases the risk of ignition should an LOC event occur. Any hot work activity not involving process critical activities would fall into this category. In addition, work that would require deactivation of any safety system, such as a fire or gas detection (as may be necessary during hot work), a fire pump, or a deluge system, is included herein.

Non-process non-critical work are considered in FLAIM to include those routine maintenance and repair activities, e.g., chipping and painting, that do not directly increase LOC risk or VESA risk, but by their very presence onboard, may add to platform supervisory and manpower demands, thereby contributing to overall increase in platform risk during simultaneous operations.

7..2 *MULTIPLE OPERATIONS ASSESSMENT (MULOPS)*

Simultaneous operations are, in general, significant risk contributors depending on the nature and number of simultaneous operations occurring; this is especially true whenever downhole work is in progress on live (capable of flowing) wells. Large platforms may have several contractor crews engaged in different construction/maintenance activities at the same time, and while normal production and drilling activities are also taking place. This proved to be a significant factor leading to the Piper Alpha incident.[9]

FLAIM recognizes that platform risk levels are time dependent, varying in both the long term, e.g., emerging safety deterioration trends, and in accordance with the nature of daily operations. MULOPS assesses the frequency and nature of those activities that produce short periods of high operational risk.

MULOPS seeks to evaluate the relative risk of simultaneous multiple operations by establishing their nature, relative proximity to each other, and the frequency of their occurrence. Simultaneous operations during production may include drilling, workovers, wireline operations, refueling of onboard fuel supplies, off/onloading bulk supplies, pig launching and receiving, and various construction and maintenance activities, such as installation of riser safety valves.

7.3 *OPERATIONAL MANAGEMENT OF CHANGE (OPSMOC)*

MARW activities often result in a change to the original facility design and operational scheme. In fact, throughout its life, a typical production platform is subject to a continual ongoing program of change intended to improve efficiency, enhance operability and safety, and implement technical and mechanical innovations as field production characteristics change, new regulatory requirements are enacted, and improvements in equipment become available. Both physical changes and personnel/operational changes can greatly impact fire and life safety risks. Often times however, "change" has not been recognized as a stand-alone risk factor; a factor that must be continually and systematically managed.

Management of Change (MOC) is recognized as an essential element in OCS safety management programs.[10] The management aspects of managing change are addressed in **Chapter 10** (SAMSA). **Chapter 7** addresses operational implications of changes that may directly affect platform safety, including changes in facilities and operational procedures.

Field modifications are often made on an emergency basis in order to preserve production rates or extend run times until the next scheduled turnaround. Some changes may not receive adequate engineering consideration in regard to their effect on other systems (e.g., Flixborough, 1974), or may not be properly executed in the field, such as poor quality field welds.

Additionally, many unplanned repairs are deemed to be temporary, and may not be performed to the same level of robustness as required for long-term operation. However, "temporary" repairs have a tendency to become permanent fixes as new demands push good intentions aside -- until the repair exceeds its temporary operating life and unexpectedly fails. See **Chapter 5,** Vulnerability to Escalation Assessment (VESA), which addresses the problem of temporary repairs in piping and pipelines.

Operational changes occur when facilities are modified. In some cases, this results in a choice of alternative modes of operations, e.g., the installation of a new gas treating scheme. FLAIM recognizes that operational safety depends to a large extent on both training and experience of operating personnel, and their familiarity with production operations. Operational safety, however, can be jeopardized by situations in which alternative production schemes that may be only occasionally used are put into service without proper preplanning or rehearsal. Such as the case in the Piper Alpha incident in which operators were attempting to realign the gas treating mode.[11]

FLAIM seeks to determine if facility modifications have introduced additional operational complexity factors, such as startup/operating modes with significantly different procedures, control schemes, or operating demands that can increase the risk of human error when used.

7.4 *ASSESSMENT OF OPERATOR DEPENDENCE AND RESPONSE (OPSDAR)*

The extent to which safe operations and control of emergency situations depends upon operator response is an important risk consideration. Platform process systems designed with protective systems that automatically sense and initiate corrective actions to developing emergency situations are apt to be less vulnerable to errors in human judgment or lack of prompt operator response. Assuming compliance with the provisions of API RP 14C for surface safety systems, FLAIM seeks to evaluate the extent to which the platform design and operational scheme places reliance on operator response and judgment in order to safely shutdown topside systems and respond to LOC events.

To accomplish this assessment, FLAIM uses a what-if scenario based approach to determine if emergency response plans are inadvertently placing too much reliance on operators performing critically important tasks or otherwise (overburdening) platform personnel to ensure safety. For example, FLAIM asks if platform blowdown system valves are automated or if operators must manually open them to depressure system piping; are platform deluge systems automatically actuated or must operators manually open local control valves; are deluge systems provided or are operators expected to fight fires manually with hand-hose lines, etc.

FLAIM asks if operator intervention is required to shutdown and depressure CIHH process system components, and what the operator must do to accomplish this: local manual valve operation, local remote actuation, remote actuation from the control room or staging area, automatic fail-safe shutdown, etc. The reliability of automatic systems is also considered in this regard, recognizing that the platform may be operating in a manual mode due to deterioration of some control loops or devices. This in turn may result in topside operating conditions that are significantly different from the philosophy initially embraced in development of emergency response and contingency plans, e.g., due to deficiencies in management of change.

For example, corrosion in deluge system piping may have forced the system to be blocked-in, with no immediate plans for replacement until the next major platform turnaround, two or more years hence. Management may have decided to rely on manual fire response in the interim without fully considering the operating crew's ability to respond to fire-fighting duties in addition to other simultaneous emergency shutdown demands. If structural fire exposure protection relied solely on the now decommissioned deluge system, topside safety and operator safety may be placed at greater risk than perceived by management or warranted by operating conditions.

Cognitive and sensory limits of operator response becomes increasing important in accident causation as the demands placed on operators increase. This problem is much the same faced by military fighter pilots who, compared with their immediate predecessors, have both a much greater array of sensory information to deal with as well as a much short time in which to arrive at correct decisions (due to higher flying velocities). The 1979 Three Mile Island nuclear plant accident was largely a result of a failure to properly sort out and recognize critically important information during the developing crisis scenario.[12]

Connelly and Koczak[13] have shown that as the span of control (number of control loops) of a control system increases, the probability of operator error also increases, and that propagation of process upsets due to increased demands on the operator also rises.

Advanced distributed control systems allow the monitoring and controlling of more system variables than ever before, but also increase the number of alarms that require the attention of any one operator. DCS system alarm annunciation may also demand further operator action to "call-up" and identify specific process system problems before an understanding of a developing scenario can be fully realized. Operator performance and efficiency drops off rapidly as the alarm rate increases, thereby slowing response time and increasing the risk of an incorrect decision or unintentional reaction.

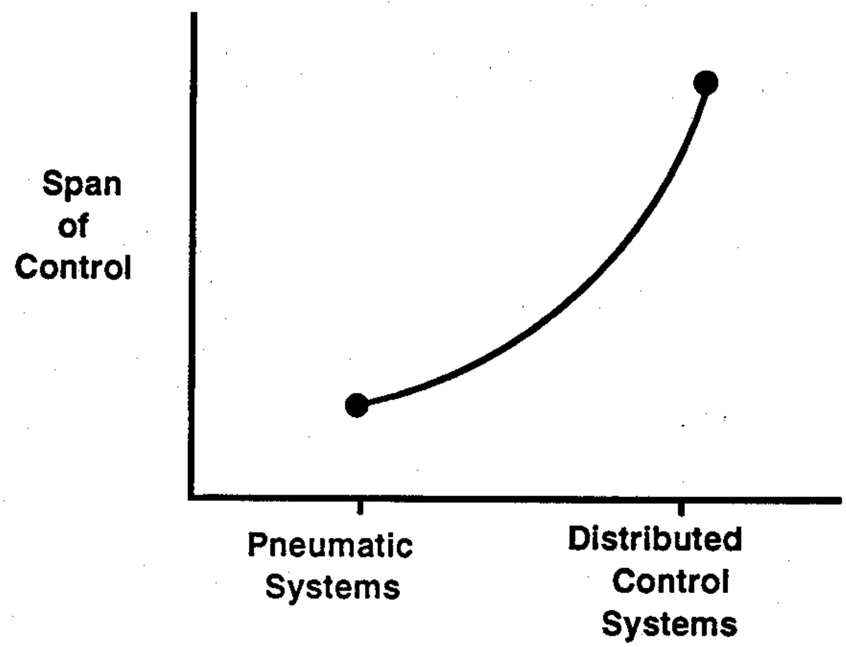

Figure 7-1

Comparison of Span of Control for Control Systems

Source: Connelly, C., and Koczak, J., *Human Factors Workshop*, API Committee on Safety and Fire Protection, Minutes of the Spring Meeting, Dallas, Texas, April 3, 1990, p.5

For example, Spurlock[14] reports on a major fire loss that occurred during a refinery unit startup in which the number of incoming DCS alarms and required operator response functions overwhelmed personnel. In the ninety minute period preceding the fire, the activity of the DCS compared to normal startup operations increased by over 440% as shown in **Table 7-1**. This rate of activity, about 2000% greater than the level of activity during normal operations, can easily exceed response capability even in the case of highly experienced and qualified operators [refer to § 10.3, Safety Training Assessment (SATA)].

Table 7-1

DCS System Events in 90 Minutes

Event Type	Events Just Prior To Fire	Events Normal During Startup	Events During Normal Operations
New Alarms	72	10	N/A
Acknowledged Alarms	65	8	N/A
Alarm Condition Clears	50	10	N/A
Operator Moves on Instrument System	43	14	N/A
Instrument Measurement Out of Range	74	27	N/A
Total Events	**304**	**69**	**15**

Source: Spurlock, M.G., *Control Operator Overload During Emergency Situations*, paper presented to the American Petroleum Institute Operating Practices Committee Executive Session, Seattle Washington, October 6, 1987, Figure 15, "Event Table for control Operator No. 3 Workstation."

A detailed analysis of control system design and efficacy may be warranted in some cases, depending on the complexity of the system and the dependence upon which platform safety is reliant on operator/system interface. This problem, however, would be more frequently encountered on North Sea platforms that traditionally rely on large, central control schemes that integrate both process control and safety functions into a common system. FLAIM asks platform operators to assess their ability to respond to process upsets and developing emergency conditions using the onboard control scheme. It seeks to determine those situations in which operators have learned to respond to emergencies by relying on their own resources or means other than the in-place control system in order to assess and respond to problems, e.g., FLAIM seeks to determine if the control system is functionally compatible with operator needs and capabilities.

7.5 *OPERATIONAL HISTORY (OPHIST)*

FLAIM includes a component intended to identify endemic operational problems as may be evidenced by reoccurring accident events. OPHIST addresses the operational history of the platform and seeks to determine if certain types of operational related events are more prone to occur. This information is intended to distinguish between appropriate changes that may need to occur and those that may have already been implemented to rectify the root cause of such events.

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[1] U.S. Mineral Management Service, *Investigation of March 19, 1989, Fire South Pass Block 60 Platform B*, Lease OCS-G 1608, OCS Report 90-0016, April, 1990

[2] for further information on this incident, refer to Appendix D of FLAIM

[3] Bea, R., and Moore. W., *Management of Human and Organizational Error in Operational Reliability of Marine Structures*, 2nd SNAME Offshore Symposium, Houston, April, 1991

[4] Ibid.

[5] *Alternatives for Inspecting Outer Continental Shelf Operations*, Marine Board, Commission on Engineering and Technical Systems, National Research Council, National Academy Press, Washington, D.C., 1990, p.42

[6] Swain, A.D., Human Reliability Analysis, Part of the Training Course Documentation for AIChE Course on Safety Analysis and Risk Assessment, American Institute of Chemical Engineers, October, 6, 1988,

p.8-11

[7] Moore, W., and Bea, R., *Human and Organizational Errors in Operations of Marine Systems: Occidental Piper Alpha and High Pressure Gas Systems on Offshore Platforms*, OTC paper # 7121, Offshore Technology Conference, Houston, May, 1993, p.7

[8] see NFPA 30, Flammable and Combustible Liquids Code, National Fire Protection Association for definitions of flammable and combustible liquids.

[9] Cullen, The Hon. Lord, The Public Inquiry into the Piper Alpha Disaster, U.K. Department of Energy, vols. I & II, HMSO Publications Centre, London, November, 1990

[10] API RP-750-OCS, Recommended Practices for Development of a Safety and Environmental Management Program for Outer Continental Shelf Operations and Facilities, American Petroleum Institute, Sixth Draft, July, 1992

[11] Cullen, The Hon. Lord, op. cit.

[12] Kletz, T.A., *Three Mile Island: Lessons for the HPI*, Fire Protection Manual for Hydrocarbon Processing Plants, Gulf Publishing, Vol. 1, Third Edition, 1985, pp. 114-116

[13] Connelly, C., and Koczak, J. (Beville Engineering, Inc., Dayton, Ohio), *Human Factors Workshop*, API Committee on Safety and Fire Protection, Minutes of the Spring Meeting, Dallas, Texas, April 3, 1990, p.5]

[14] Spurlock, M.G., *Control Operator Overload During Emergency Situations*, paper presented to the American Petroleum Institute Operating Practices Committee Executive Session, Seattle Washington, October 6, 1987

Chapter 8

LIFE SAFETY ASSESSMENT (LISA)

Assessing and managing the risk of personnel injury and death is a primary focus of FLAIM. This is accomplished by calculating the life safety index through the assessment of key occupancy factors listed in Appendix B6. **Figure 2-1,** *Primary Modular Components Used to Develop FLAIM,* illustrates where Life Safety Assessment fits into the overall safety assessment procedure used in FLAIM. **Figure 8-1** below, *FLAIM Life Safety Components* shows the how FLAIM accounts for both crew quarters and overall platform life safety.

It is difficult to isolate all factors affecting life safety into a single risk module. Users of FLAIM should recognize the interdependence of the life safety assessment risk index on each of the other FLAIM assessment modules, and especially with regards to Layout and Configuration Assessment (LACA). Similarly, a platform may have good LACA and LISA risk indices, but still present a significant risk to life safety due to a poor overall fire and life safety composite index.

8.1 *LIFE SAFETY ASSESSMENT*

Production platforms in the Gulf of Mexico (GOM) have various size crews depending on the size and complexity of the platform. Many smaller platforms are normally unattended, whereas some platforms are normally occupied and may serve as central service facilities for other smaller nearby platforms. Unlike platforms in the North Sea, however, the crew size on platforms in U.S. waters is considerably smaller. The overall average number of personnel in attendance on GOM and Pacific production platforms is estimated to be 12 persons.[1]

LISAA is executed only if a platform is deemed to be manned, e.g., a platform on which people are routinely accommodated for more than twelve hours per day.[2] FLAIM incorporates occupancy criteria to trigger LISSA based on whether the platform is actually and continuously occupied <u>by at least five persons</u>. This criteria is consistent with that adopted by the Panel on Seismic Safety Requalification of Offshore Platforms.[3] However, FLAIM recognizes that some operators may want to adjust this discriminator according to their own risk management policies.

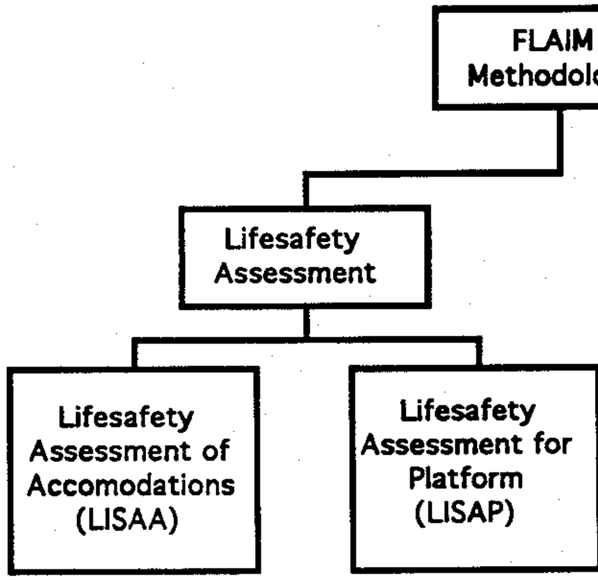

Figure 8-1
FLAIM Life Safety Components

If the platform is not deemed to be manned nor provided with living quarters (LQ), such as on a platform where the crew is rotated out each day or work-shift via helicopter or service vessel, FLAIM forgoes the LISAA component addressing accommodation facilities life safety and evaluates the overall life safety features of the platform (LISAP).

FLAIM considers that an unmanned platform always presents a lower risk to life safety than a manned platform independent of risk reduction measures. While risk reduction measures can compensate to a degree for personnel presence, their effect as allowed for in FLAIM can never totally balance the numerical penalty incurred, unless the LQ and control room is completely removed from the platform, e.g., remotely located -- such as on a separate, bridge-connected structure, or on a "flotele", or other similar means employing physical separation and isolation from the platform.

FLAIM considers all normally attended production platforms that are provided with a LQ as "High Consequence Platforms" with regard to life safety. Manned production platforms not equipped with a LQ are deemed to be "Moderate Consequence Platforms." And those facilities that do not meet the criteria for being manned are judged to be "Low Consequence Platforms" with regard to life safety.

Note that risk assessment criteria other than that based on life safety, i.e., risk to the environment, etc., may be applied for defining high, moderate and low consequence platforms for assessment of fitness-for-purpose.[4] It is also recognized that heavy reliance on helicopter transportation is generally considered the single most significant cause of fatalities on offshore platforms. Assessment of aviation and transportation risks should be performed as a separate detailed analysis and has not been included within FLAIM's components.

The LQ may or may not be designed to serve as a Temporary Safe Refuge (TSR) in the event of a fire emergency. Most existing platforms in the GOM and the Pacific region have not made provisions for TSRs. The need for a TSR must be assessed on an individual platform basis, considering environmental conditions and location (GOM & California Coast v. Cook Inlet), transportation, available outside emergency support, etc. TSR's are not specifically treated in FLAIM since, in general, open type warm water production platforms have been deemed to not require such provisions. However, in the event that operational considerations and environmental risk factors make the provision of a TSR prudent, its adequacy may be screened by applying the factors identified herein.

FLAIM considers any manned production platform that handles sour crude or gas from *production zones known to contain hydrogen sulfide,* as defined by the MMS-OCS Orders, to be both high consequence and high life safety risk facilities. In this regard, zones known to contain H_2S refers to those platforms where reservoir conditions are such that even small leaks/releases from process or drilling equipment, e.g., fugitive emissions, could result in an instantaneous exposure of personnel to an airborne concentration of 20 ppm H_2S or higher.[5]

In the event that H_2S is a known hazard, FLAIM calls for a specialized life safety assessment to be performed. This component of FLAIM is for future development and is not covered in the scope of this present work.

8.2 *LIFE SAFETY REGULATIONS*

The United States Coast Guard (USCG) has responsibility for workplace safety and health regulations for OCS production platforms.[6] The scope of USCG regulations includes personal protective equipment, general workplace safety, life saving appliances and fire fighting equipment. In addition, minimum requirements for platform evacuation and escape are prescribed by the regulations.[7]

While individual personnel safety considerations are of course important to crew welfare, FLAIM has not addressed matters of general practice such as guarding of machinery, openings in the deck, or elevated platforms and walkways. Nor are such individual items such as personal flotation devices, safety belts & lifelines, protective clothing, safety showers, etc. specifically treated. FLAIM's LISA component is focused instead on matters affecting the collective welfare of the crew with regard to the means of egress and escape, and protection from fire and explosion effects. FLAIM assumes that the production platform is routinely inspected by the USCG and meets the minimum prescribed requirements as mandated by law.

Life safety provisions for onshore facilities are generally prescribed by code, such as the NFPA *Life Safety Code* .[8] NFPA 101 addresses ten general areas affecting building life safety as follows:

- fire resistive construction
- fire compartmentation
- protection of vertical openings
- design criteria for exits (means of egress)
- emergency lighting and exit illumination
- fire alarm systems
- smoke control systems and design considerations
- flame spread and smoke generation of interior finishes and furnishings
- protection of hazardous areas in a building
- protection of building service systems and equipment

As Slye[9] discusses, NFPA 101 excludes offshore platforms from its scope of application in recognition of the unique nature and demands placed on these structures; Slye notes that for this reason USCG regulations take precedence over the Life Safety Code's requirements.

Both NFPA 101 and USCG regulations are prescriptive rather than performance oriented; they both prescribe deterministic requirements to achieve an acceptable level of life safety. As mentioned in §2.2.6, Nelson developed a performance life safety evaluation system to demonstrate code equivalency for health care facilities, known as the *Fire Safety Evaluation System* .[10] Nelson used three major components in his methodology to determine code-equivalency:

- Occupancy Risk -- accounting for the number of people affected by fire, their ability to respond to fire and take protective measures, and the likely fire scenario and fire intensity anticipated

- Building Safety Features -- accounting for the building's safety and fire protection systems and capability to mitigate the associated occupancy risks

- Safety Redundancy -- the degree to which independent means of protection are provided such that in the design of the overall fire safety system,[11] failure of a single component or method would not precipitate a complete failure of the entire safety system.

Chapman and Hall[12] applied Nelson's systems approach to develop a mathematical cost-optimization model for fire safety retrofit expenditures in existing hospitals. The model allows determination of the least-cost means from alternative code-equivalency approaches that satisfy life safety code requirements. A similar approach may be applied to offshore production platforms using FLAIM.

However, in the case of USCG regulations regulating life safety, there would be relatively little incentive to optimize compliance alternatives due to the general lack of specificity in the requirements. Quite simply, manned platforms are required to be provided with at least two primary means of escape,[13] extending from the uppermost platform level that contains living quarters or other areas that personnel may continuously occupy, to each successively lower working level and to the water surface.

For unmanned platforms USCG regulations require only one primary means of escape as described above, plus the provision of one or more secondary means of escape when the platform is occupied, depending on the number of personnel onboard.

There are no requirements in USCG regulations for protecting the structural integrity of the means of escape, nor for protecting personnel from fire and smoke exposure while making their escape. From a compliance standpoint, two unenclosed (open-air) vertically fixed steel ladders located at diagonally opposite sides of a platform would satisfy the code, without regard to the total number of crew or the relative exposure risk they may be subjected to during an emergency.

This is in contrast to Cullen Report recommendations following the Piper Alpha disaster that calls for a detailed risk analyses of platform evacuation provisions and escape routes. For typical GOM platforms, low occupancy loadings and favorable environmental conditions, as compared to platforms in the North Sea, have contributed to the perception that such elaborate measures are unwarranted for achieving adequate levels of life safety. This perception is further corroborated by the historical record to date;[14] however, as field development moves into ever increasingly deeper waters, demanding GOM platform designs more akin to their North Sea cousins, predictive hazard analysis methodology rather than experience-based techniques may prove to be the better approach for determining life safety needs.

For both manned and unmanned platforms, LISAP seeks to assess the relative safety of platform egress routes and escape provisions, recognizing that USCG regulations require detailed Emergency Evacuation Plan (EEP) for manned platforms and monthly emergency drills, as well as annual emergency evacuation drills. As mandated by the regulations, the EEP must contain several elements and is subject to approval by the responsible Marine Inspector. One of these components requires that the facility operator describe the recognized circumstances in which platform personnel would be placed in jeopardy, including fires and blowouts, and that could require platform evacuation. For each circumstance or condition, regulations require that pre-evacuation steps for securing drilling and production operations be determined, including personnel required to accomplish the tasks and the required response time.

In addition, USCG regulations ask operators to determine the order in which personnel would be evacuated, the transportation sources to be used in the evacuation, and the operational limitations for each mode of transportation specified, including the time and distance factors for initiating evacuation. The duties of all personnel involved in emergency response are required to be recorded and posted in the form of a muster list or station bill.

LISAP asks if, in the event of a significant fire in any given area of the platform, how easy or difficult would it be to escape. LISAP seeks to identify those areas on a platform which, due to the degree of congestion as may be caused by equipment, piping, structural steel elements, on deck storage, etc., or due to the configuration of the arrangement, personnel could reasonably anticipate difficulty in effecting their escape with one of the two primary means of egress blocked by fire or smoke.

FLAIM recognizes that most platform operators place a high emphasis on the welfare of the crew and provide more than the minimum called for provisions for egress and evacuation. Many if not most platforms have multiple means of escape and are equipped with two or more enclosed escape craft (survival capsules). The crew is usually well trained in their use, having an inherent interest in their successful deployment. Nevertheless, due to platform modifications or initial design limitations, it is not unusual to find that reliance is being placed on primary escape routes that are inherently flawed due to exposure to likely leak sources, such as pumps and other potential fire exposures.

LISAP asks if primary escape routes are exposed by adjacent process equipment or if other means of risk mitigation, such as firewalls, water sprays, etc. have been provided to afford additional protection to escaping personnel. In addition, the times required to secure the platform and disembark via the primary and secondary means of escape are assessed.

LISSA evaluates that adequacy of onboard accommodations with regard to life safety. LISSA addresses those elements previously listed as addressed by the Life Safety Code, including combustibility of construction and interior finishes, exterior fire walls and exposure protection, the means of egress, emergency lighting, and fire detection and alarm. The location of the living quarters is assessed in LACA, Chapter 6.

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[1] Committee on Alternatives for Inspection of Outer Continental Shelf Operations, *Alternatives for Inspection Outer Continental Shelf Operations*, Marine Board, Commission on Engineering and Technical Systems, National Research Council, National Academy Press, Washington, D.C., 1990, p. 9

[2] American Petroleum Institute, Recommended Practice 14G (RP 14G), *Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms*, Second Edition, May 1, 1986, p. 3

[3] American Petroleum Institute, *Seismic Safety Requalification of Offshore Platforms*, prepared for API by Iwan, Thiel, Housner and Cornell, May, 1992

[4] Martindale, Krieger et al., *Strength/Risk Assessment and Repair Optimization for Aging, Low-Consequence, Offshore Fixed Platforms*, Offshore Technology Conference, OTC paper # 5931, Houston, May, 1989

[5] U.S. Code of Federal Regulations, 30 CFR Part 250, §250.2 (OCS Orders -- Definitions), July 1, 1992 edition

[6] Ibid., 33CRF Subchapter N -- Outer Continental Shelf Activities, Part 140

[7] Ibid., 33CFR Subchapter N - §143.100

[8] National Fire Protection Association, NFPA 101, *Life Safety Code*, 1991, pp. 1-327

[9] Slye, O.M., *Unusual Occupancies*, NFPA Fire Protection Handbook, Fifteenth Edition, September, 1981, Section 6, Chapter 10, pp. 6-68 -- 6-69

[10] Nelson, H.E. and Shibe, A.J., *A System for Fire Safety Evaluation of Health Care Facilities*, National Bureau of Standards, Center for Fire Research, U.S. Department of Commerce, NBSIR 78-1555, November, 1978

[11] The overall fire safety system is used herein to connote both active and passive fire protection provisions, as well as the means of egress and ability to relocate and move people.

[12] Chapman, R.E., and Hall, W.G., *Code Compliance at Lower Costs: A Mathematical Programming Approach*, Fire Technology, Volume 18, Number 1, February, 1982, National Fire Protection Association, pp. 77-89

[13] A primary means of escape is defined by USCG regulations as a fixed stairway of fixed ladder of metal construction. A secondary means of escape also includes the use of portable, flexible ladders, knotted ropes, and other devices satisfactory to the Officer in Charge, Marine Inspection. See U.S. Code of Federal Regulations, 33CFR §143.101

[14] There were a total of 206 fatalities reported to the MMS on OCS platforms over a 32 year period between June, 1956 and December, 1988. Most of these fatalities are the result of non-fire incidents, such as handling of heavy loads, falls, drowning, and helicopter crashes. Refer to Alternatives for Inspecting Outer Continental Shelf Operations, Committee on Alternatives for Inspection of OCS Operations, op. cit., Marine Board of the National Research Council, 1990, p. 18 & 32.

Chapter 9

RISK REDUCTION MEASURES ASSESSMENT (RIRA)

Chapter nine accounts for specific platform design features/risk reduction measures (RIRA) which serve to mitigate the risk of fire and life-loss on production platforms. FLAIM has been designed to correlate platform design and operating conditions so that appropriate risk reduction measures can be assessed relative to the risk contributors, e.g., process risk factors, fire safety risk factors and life safety risk factors. FLAIM's design is intended to allow independent assessment of risk reduction measures and their impact on the overall topsides risk index. In this manner, the relative merits of various mitigation measures can be tested in terms of a what-if cost/benefit analysis using the index as a discriminator for reaching safety target levels.

9.1 *ACTIVE FIRE PROTECTION & LIFE PROTECTION SYSTEMS*

The ability to control and contain small fires by limiting their thermal impact and effecting extinguishment is vitally important to any offshore platform. Active fire protection systems include those fixed (non-mobile) systems that actively respond to incipient fire conditions using an external source of energy. The platform firewater system is the most basic of active systems. Other systems include fire detection systems, combustible gas detection systems, chemical fire suppression systems (foams, gases, and powder chemicals), and alarm and communications systems. Also included are the power sources, power distribution systems, and instrument and control loops required to power, monitor and actuate these systems. The importance of inspection and testing is addressed in § 9.7.

9.1.1 Platform Firewater Systems

Most production platforms are required to have a fixed firewater system consisting of pump(s) and driver(s), a firewater distribution system, and firehose stations and/or fixed firewater monitors, as described by OCS Orders.[1] The OCS Orders require the provision of firewater in all areas where production-handling equipment is located to "provide needed protection." In addition, enclosed well-bay areas in which hydrocarbon vapors may accumulate are required to have fixed water spray systems.

Needed protection, as used by OCS Orders, is not explicitly defined; however, the

Orders require conformance to the recommendations of API RP-14G, § 5..2, Fire Water Systems.[2] In addition, the OCS Orders specify that fuel or power for firewater pump drivers by sufficient to achieve at least a 30 minute run time during a platform shut-in.

API RP-14G is also prescriptive in nature and calls for a pump capable of discharging a minimum of 180 gallons per minute (gpm) at 75 psi pressure, e.g., with two fire water hose streams in simultaneous operation. Pump performance characteristics (pump curve) should conform to the requirements of NFPA 20, Standard for the Installation of Centrifugal Fire Pumps. Beyond this, however, the only requirements called for by RP-14G, "should the operator choose a more elaborate (firewater) system," is for the pump capacity to be "sufficient to perform the functions required by the fire control design." Neither OCS Orders require nor API recommended practices suggest that only pumps meeting all requirements of NFPA 20 be used for firewater.

The fire control design functions referred to in RP-14G are neither specified in a performance nor prescriptive manner. Operators with a "code-compliance" mentality, therefore, could conceivably meet minimum OCS Order requirements by providing a single 180 gpm @ 75 psi fire pump with a one-half hour fuel supply, regardless of what prudent risk management practices might otherwise suggest.

FLAIM recognizes that many factors must be accounted for in evaluating the fire protection needs of any particular platform, and that generalized criteria based on "rules-of-thumb" regarding system design capacity can be misleading. However, there are some generalized correlations with regard to the physical size of a platform, its operating conditions, the amount of flammable liquid inventory in storage, the extent to which firewater is relied on to provide exposure protection to structural steel members (in addition to effecting fire control measures), and the overall residual risk levels of the platform which could be used to assess the relative adequacy of the firewater system design capacity.

FLAIM has been designed to correlate platform design and operating conditions as reflected by process risk factors, fire safety risk factors and life safety risk factors, with appropriate risk reduction measures. Platform firewater system design is ranked in accordance with fire safety and life safety consequence levels; high consequence platforms should be provided with strong and reliable firewater systems. Correspondingly low consequence platforms are judged to a lower standard. Ultimately, however, the user is asked to establish what are reasonable criteria for assessing platform needs based on actual operating conditions.

In addition, FLAIM considers issues of reliability and redundancy, seeking to identify possible common-cause failures and close-coupling exposures that could lead to system outages in times of emergency. For example, the provision of a spare fire pump adjacent to the main fire pump creates the potential for a mutual exposure scenario that may disable both pumps with a single event. Conversely, two remotely located pumps may be protected from close-coupling exposure scenarios and yet may be subject to common-cause failure if, for example, both pumps depended on electric power that was provided or distributed via a single source/route.

FLAIM recognizes that the best conceived, designed and installed fire protection systems may prove to be of little or no value if not properly tested and maintained. FLAIM asks about the functionality of the firewater system in its present condition, and assesses its likelihood to perform as intended in accordance with design criteria.

9.1.1.1 Fire Pumps and Drivers

Pumps and drivers used in fire protection systems must be reliable. They must be able to meet certain performance characteristics (pump curve design points) as well as have mechanical and electrical design features intended to ensure higher levels of reliability than that typical of commonly used process pumps. Most fire pumps used for onshore applications are "UL listed"[3] or "FM approved" packages (unitized pump and driver assemblies) designed to NFPA Standard No. 20.

Listed and/or Approved fire pumps are constructed in one of two ways: 1) either vertical or horizontal split-case, end suction centrifugal pumps or 2) vertical-turbine (line-shaft) type pumps. On most production platforms sea water is used for platform firewater, requiring a line shaft type pump. Platforms with recognized (listed or approved) fire pumps utilize vertical-turbine pumps in which the pump impeller is located in a bowl located below the mean low-low water level and connected to/driven by either a diesel or electric motor via a long vertical pump shaft (line shaft) running inside pump's discharge column.

It is not uncommon to find that many platforms do not use approved or listed fire pumps to provide firewater. For example, some platform operators prefer to use downhole submersible pumps such as those commonly used for pumping crude oil from pressure-depleted reservoirs.[4]

There are several reasons for this: 1) vertical turbine pumps can be difficult and expensive to maintain, they tend to be prone to vibration problems as line shaft lengths increase -- especially in regions where heavy seas are frequent. The alignment of line shaft pumps must be maintained true in order to avoid shaft wear, bearing failures, excessive vibration, and even seizure of the pump. However, this is often difficult where shaft lengths of 100-200 feet are involved, 2) pump columns must be placed close to vertical jacket members to allow bracing, often limiting the placement of fire pumps during initial design. It is not uncommon to find the standby fire pump located adjacent to the primary pump due to such design constraints, thereby creating a common cause failure risk by reason of proximity, and 3) topside pump gear boxes and drivers require valuable deck area -- especially diesel driven pumps that may require several square meters of space.

Additionally, pulling the pump bowl and impeller requires disassembly of the line shaft and column section by section. This not only is a time-demanding exercise, but also requires sufficient vertical clearance and overhead crane access, and 4) submersible pumps and drivers are not directly subject to fire and explosion damage. Of course, the source of topside electrical power may be destroyed, and power and control cabling may be susceptible to damage thereby rendering the pumps inoperable.

One design proposed in 1979 and endorsed by wild-well fire fighters Boots Hansen and Coots Matthews (of Boots & Coots fame) uses submersible pumps powered by an off-platform electrical generator located on a nearby mooring buoy or SBM. The design, referred to as Standby Offshore Systems (SOS), was conceived following Phillips Ekofisk Bravo platform blowout in April of 1977.[5]

Unlike some prescriptive code requirements or underwriter specifications, FLAIM seeks to address issues of performance rather than base judgments solely on conformance. Conformance to standards, while indicative of a certain level of reliability, cannot necessarily ensure performance nor the best solution for particular circumstances involved. Consequently, FLAIM does not discredit a platform's firewater system simply because the fire pumps may not be "list or approved" as would normally be required for a comparable onshore installation.

FLAIM asks if the production platform's fire protection system relies on other than listed and/or approved fire pumps and fire pumping system components for providing 100 percent of the assessed flow requirements. In the event that non-listed/approved pumping systems are being relied upon for firewater, FLAIM seeks to establish the relative reliability of the system based on past operating history and problems. It also asks the user to assess if there is sufficient redundancy in the system to avoid single point/common cause failure scenarios, such as electric power failure, and reliability to ensure continued operation during abnormal conditions.

For example, most electrically driven process-type pumps are typically provided with equipment and circuit protection to protect both the power cables and the motor. However, as specified by the National Electrical Code,[6] fire pump motors have special requirements intended to ensure operation of the motor during fire emergencies and under service conditions that would otherwise cause conventionally protected motors to trip out.[7] For example to ensure continued operation of the fire pump during a fire, individual short circuit protection of the power feeder is not required, and the running overcurrent protection (overload relays) usually provided for continuous duty process pump motors should be omitted. The pump and pump motor in fire service applications should be matched such that under maximum pump discharge conditions the motor cannot be overloaded.

In addition, motor controllers and power circuits for platform fire pumps should conform with special requirements called for by API RP-14E,[8] recognizing that these practices may differ from the NEC requirements.

For example, all fire pump motor cabling should be sufficiently fire resistant so as to remain operable for at least thirty minutes under direct flame impingement, including all feeder and control cables, e.g., mineral insulated (MI) cable. Stainless steel or other fire resistant materials should be used to secure motor power and control cables, and fire pump motor controllers should be equipped with oversized thermal heaters.

The selection of pump construction materials is an important factor in regards to pump reliability, maintenance requirements, and service life. Pump materials vary considerably in both cost and performance. Pump cases, bowls and wetted components can be made of various alloys, such as nickel-cast iron or "Ni-Resist" (e.g., Platform Hidalgo), aluminum-bronze alloy (e.g., Platform Esther), and nickel-aluminum-bronze (Platform Julius). These materials differ significantly.

Ni-Resist is suitable for cold sea water services (<60°F) and is the least expensive; however, it is difficult to cast and will usually require weld repair -- which in turn is difficult to properly perform because the weld rod material (nickel) does not chemically match the base metal.

Aluminum-bronze alloy, such as ASTM B148 Grade C95200, C95300, or C95400, is easier than Ni-Resist to cast and repair, and has better corrosion resistance in sea water. However, it is also more expensive than Ni-Resist, and requires all cast components to be temper annealed to 1250°F for a minimum of two hours followed by rapid air cooling. This is to correct micro-segregation of the aluminum and bronze, which can lead to localized inter granular corrosion if left untreated.

Nickel-aluminum-bronze, such as ASTM B148 Grade C95500 or C95800 is deemed to be the best material for both corrosion and erosion resistance in sea water, and is only slightly more costly than aluminum-bronze. Grade C95800 does not require temper annealing of the raw castings provided that the % Al is controlled relative to the nickel content. This does not hold true for Grade C95500 which requires temper anneal treatment to avoid micro-segregation.

The initial capital cost penalty for specifying all wetted pump components as nickel-aluminum-bronze as compared to Ni-Resist with steel epoxy coated column pipe and pump head is between two and three times as expensive. However, life cycle costs in terms of maintenance and repair can quickly repay the initial capital premium.

The location and arrangement of fire pumps deserves special mention. Fire pumps are the heart of a platform's fire protection system. A disabled fire pump during times of emergency can have disastrous consequences, as demonstrated by the Piper Alpha tragedy[9] (the platform's fire pumps had been disabled due to the presence of divers in the water and concern over suction forces imperiling their safety in the event a pump suddenly started).

Fire pumps should be located in low fire risk areas on the platform and protected from fire and possible damage from blast waves and shrapnel. Fire pump enclosures are commercially available[10] that have been designed and certified to meet A-60 (one hour fire rating) test protocol as specified by the International Maritime Organization (IMO). If a fire pump room is provided, it should be constructed to fire resistive standards and be provided with automatic fire protection systems.

As already discussed, diesel engine runaways caused by flammable vapor ingestion is a known high risk factor on OCS platforms. MMS has responded to this problem by requiring shut-off devices in the combustion air intakes. For fire pumps however, engine shutdown during instances of vapor release may not be a viable alternative. Ventilation air for fire pump rooms and combustion air for engine drivers should be free from the possibility of contamination by hydrocarbon vapors. Providing a combustible gas detector to shut down the diesel driver in the event of vapor contamination will do little good in a fire emergency unless there is a 100% backup unit remotely located in a vapor-free area.

At least two independent sources of firewater should be provided, either of which with the capacity to meet 100% of the anticipated maximum flow and pressure demands. The pumps should be separated from each other to minimize risk of common-cause failure from external events. Further, they should have independent power sources, such one or more diesel engine drivers, or if electric, powered by separate power sources and distribution systems that are not subject to mutual exposure (this is often times unfeasible, necessitating at least one diesel driver for assured redundancy).

If one or more fire pumps are electrically powered, the primary power source should have a remotely located standby generator that will automatically come on line whenever any electric fire pump starts or when the main generator is down. The standby generator should be sized to handle the maximum inrush starting current of all electric fire pumps required to meet 100% of the fire demand. Power and control cables for each pump should be separately routed and protected from both blast and fire exposure.

Fire pumps should be designed to automatically start on pressure demand and to be manually shut down at the pumps motor controller. Manual pump start switches can be located in the control room; however, pump shutdown controls should normally only be located locally at the pump driver. Normally a small centrifugal (jockey) pump (50-100 gpm) is used to maintain system pressure in the ring main at approximately 100 psig.

Engine driven fire pumps preferably should have diesel drivers, although engines powered by gasoline, natural gas and liquefied petroleum gas are found in fire pump services. Only diesel fueled engines, however, are recognized by NFPA for fire pump service for reasons of reliability. The NFPA standard[11] for combustion engines and gas turbines addresses special provisions recommended for engine driven fire pumps. This includes ensuring that engine instrumentation, such as high cooling-water temperature and low oil pressure sensors do not affect engine shutdown, but rather alarm only.

The engine cooling system is a very important design consideration affecting overall system reliability. Fire pump engines should be equipped with closed circuit cooling systems with shell and tube heat exchangers, where cooling water (tube side) is taken from the discharge side of the fire pump and used to cool the engine block coolant (shell side). Conventional air-cooled radiator systems are not recommended. One reason is that due to infrequent use, radiator-type systems are prone to sedimentation and fouling, leading to overheating. In addition, leaks in a conventional radiator type system can cause loss of engine coolant and overheating, whereas leaks in the heat exchanger tubes will only result in sea water contaminating engine coolant, but will not affect engine performance during a fire.

On an offshore platform, there is a limitless supply of firewater for the taking. Matching this is virtually an unlimited fuel source controlled only be successful operation of the platform's emergency shutdown provisions. The limiting factor in this balance is the amount of fuel available to supply the firewater pumps. OCS Orders specify a minimum of 30 minutes; this is obviously in contemplation of very limited fire response scenarios using one or two hand hoselines. The National Fire Protection Association calls for a minimum fuel supply of eight hours, or greater if facilities for prompt refilling of the supply tank are not available. Where reliance is placed on exposure protection for structural integrity using water spray, FLAIM uses NFPA's criteria as a basis for ranking fuel system capacity. FLAIM asks if alternative provisions have been made to ensure continued operation of platform fire pumps, such as duel-fueled engine drivers, steam turbines, or other means to provide redundancy. Testing is addressed in § 9.7.

9.1.1.2 Firewater Distribution Systems

As the fire pump is the heart of the fire protection system, so are the firewater mains (feeders) its arteries. And much like arterial problems in humans, firewater mains, branch lines, and user connections are subject to increasing problems with age, including interior and exterior corrosion, scaling, valve failures, and leaks. FLAIM seeks to assess the general condition of the firewater distribution system, its ability to supply the anticipated maximum probable waterflow demand, and its vulnerability to damage and failure from external events, e.g., dropped objects, explosions, etc.

It is generally recognized that a looped and girded arrangement (ring main) is more reliable than a single distribution trunk supplying branch lines in a tree arrangement. Ideally, the fire pumps should be located remotely from each other and connect to the distribution loop on opposite sides, thereby minimizing the impact of the loss of one pumping station. Sectional valves for isolation of the fire loop should be provided to allow damaged and leaking portions of the line to be isolated with minimal impact on the entire system.

Ring mains do not necessarily have to be configured in a horizontal orientation. It may be more advantageous to install "vertical-loops" in order to avoid long runs of piping in high risk areas thereby reducing susceptibility to explosion damage.

Plain carbon steel pipe has generally proved to be inadequate due to short service life. Carbon steel has an average internal corrosion rate of 0.64 mm/year in fully oxygenated sea water systems, and can average as high as 1.8 mm/year where stagnant flow conditions exist.[12] Some companies use cement lined, epoxy lined, galvanized, or even plain carbon steel that is externally wrapped and coated, combined with impressed current cathodic protection systems and corrosion inhibitors. Other operators have found the performance of alloy piping, such as 90-10 copper-nickel pipe, to far outweigh the initial added cost penalties.

Lined steel pipe can be difficult to work with and has several disadvantages from an installation standpoint with regard to making subsequent modifications to the piping system . Shop fabricated "spool-pieces" may be required to import from onshore in order to ensure that pipe sections have been properly welded and internally coated. Cement lining is also subject to spalling from mechanical impact, improper lifting/handling, and from low frequency-large amplitude vibration as may be caused by wave action. Loose pieces of cement within the piping system can plug hose nozzles, sprinklers heads, and damage pump impellers. Exposure of even small areas of the base metal to sea water can result in rapid preferential corrosion and loss of serviceability.

Epoxy lined and galvanized steel pipe cannot be effective if the application of the internal coating has not been properly performed or is otherwise violated during welding and installation. Like cement lined pipe, if the epoxy coating or galvanizing is not properly applied or is damaged by hot work, rapid failure can follow.

Alloy piping such as 90-10 copper-nickel, aluminum-bronze and admiralty brass has been successfully used for sea water piping systems by the world's navies and on North Sea platforms (e.g., Claymore Platform)[13] for many years. U.S. operators, e.g., Exxon, Chevron, et al., are also turning to alloy pipe for replacement of carbon steel systems that are no longer functional due to excessive internal and external corrosion.

Copper-nickel alloy piping is generally the material of choice, but requires care in handling and during installation. Its lighter weight and thinner wall thickness than carbon steel makes it more susceptible to damage from improper handling. Special welding skills are required such as tungsten inert gas process and silver brazing techniques. In addition, care must be taken to engineer supports so as to ensure isolation from dissimilar metals to prevent electrolytic activity and galvanic corrosion. Moreover, its lower mechanical strength than carbon steel increases its susceptibility to damage from dynamic blast effects, e.g., drag forces (see § 9.6.3, Blast Resistant Construction and Blast Hardening). Copper-nickel alloys are also very susceptible to sulfide attack; fire water mains with cross-connections to produced water injection systems should consider the possible presence of sulfides.

FLAIM seeks to establish the reliability and capacity of the firewater system to deliver system design flow rates at needed residual pressures. It asks about the age of the system, what are the materials of construction, and asks the user to assess the overall condition of the system and its state of readiness. FLAIM asks if flow tests have been performed on the firewater system in order to determine the system flow characteristics and the effective "C" factor. FLAIM also asks what is the expected flow from the system at the hydraulically most remote location on the platform, e.g., normally the helideck, when flowing firewater at 100 psig residual pressure. The extent of temporary repairs made to keep the system operational are identified.

The firewater system should be dedicated for emergency purposes only; however, some operators have combined utility water needs with firewater service. FLAIM asks if the firewater distribution system is used for any other purpose, such as utility wash water or cooling service. FLAIM asks if the system is looped and provided with sectional valves to permit isolation of leaking or damaged section of the main without loss of service to the entire platform. FLAIM also asks about how the firewater main is connected to the fire pumps, seeking to identify places of single point system failure, and how often tests are performed.

9.1.1.3 Firewater Hose Stations, Hydrants, and Monitors

All areas on a production platform should be reachable by at least two hose streams from opposite directions using no more than 100 feet of hose. FLAIM asks if hydrant and hose station locations are adequate to meet this criteria.

The type of hose used is also important. In the confines of platform, the use of long lengths of collapsible hose is difficult due to lack of clear laydown areas. Ready-connected "live" hard rubber hose reels are ideal for quick first-aid type response. The hose does not have to be unfolded and layed out and then pressurized before use. Live hose reel stations allow operators to simple pull as much hose off the reel as needed to reach the fire area, and then open the nozzle to begin water application.

Hose size directly affects friction loss and flow capability. One inch hard rubber hose stations are easier to handle by one person but have limited flow capability. One and one-quarter inch hose can still be handled by one person and has better fire-fighting capability than one-inch hose. One and one-half inch hard rubber hose, while providing good flow characteristics, is too difficult for one person to easily handle and normally requires two people to maneuver in fighting the fire.

Some operators believe that larger diameter hose is also important to maintain onboard a platform in order to provide the flows required for fighting large fires. For platforms with large open deck areas, one and one half inch, two inch, or two and one-half inch collapsible hose may be successfully employed for fire control. However, in most cases, platform configuration will limit the usefulness of large diameter collapsible hose.

Firewater monitors are sometimes used on production platforms to deliver large quantities of water for fire fighting and exposure protection. Exposure protection may be for a particular piece of equipment, such as a production separator or gas compressor, for protection of structural steel members, such as the substructure of the drilling derrick, for protection of important buildings such as the crew quarters, or for protection of personnel escape routes and staging areas. Firewater monitors are also occasionally used for control of incident radiant heat from near deck level flare booms.

Fixed firewater monitors can be rapidly put into service with the opening of a single valve, aimed and adjusted for the appropriate stream pattern for the situation, and left unattended while in operation allowing personnel to tend to other emergency response activities. Monitors are normally placed in easily reached locations around rather than within process areas so as to permit access during fire emergencies. They are particularly suited for platforms with large contiguous open decks and bridge-connected platforms, as well as for protecting helidecks.

Fixed firewater monitors are of limited benefit in congested areas in which structures, equipment, and other interferences can disrupt the water stream before it reaches its intended target. It is also not uncommon to find that monitors that were initially well placed have become blocked by subsequent equipment additions and platform modifications the did not include revising monitor locations in the scope of work. One approach around this problem is the provision of portable firewater monitors to supplement fixed monitors and hose streams.

Portable monitors, like fixed monitors can be deployed and left unattended to perform exposure protection and fire control functions. However, unlike fixed monitors, they require hoselines to be layed and connected to hydrants before they can be used. Therefore, depending on platform accessibility and layout, their use may or may not be appropriate, e.g., reliance on the use of portable monitors must account for the crew's ability to effectively deploy them in times of emergency.

In high risk process areas, such as the well-bay, production modules, and gas compression/treating modules, the most appropriate approach to providing effective fire control and exposure protection may be fixed water spray systems.

9.1.1.4 Fixed Firewater Spray /Deluge Systems and Sprinkler Systems

Fixed firewater spray systems, deluge systems and automatic fire sprinkler systems are in use on offshore platforms around the world. There are many variations of system design the can be generalized into two basic groups:

• automatic closed-head wet-pipe and dry-pipe sprinkler systems

• automatic/manual open-head water spray and deluge sprinkler systems

Sprinkler systems are generally used for protection of non-process related areas and equipment, such as the crew quarters, storage areas, workshops & machinery areas, and perhaps the fire pump enclosures. Their primary operating characteristic is a fusible element in the closed sprinkler head that must first be heated to its operating temperature before it opens to release water under pressure (or, depending on its function, control air). Water discharge is from only those individual sprinkler heads that have been thermally actuated, and only after the head has been sufficiently heated so as to fuse.

Automatic or manual open-head water spray and deluge sprinkler systems are used in process areas for exposure protection and fire intensity control and suppression. These systems provide water discharge through all spray nozzles or sprinkler heads within the fire area (zone), and consequently have much higher water demands than a comparable wet pipe sprinkler system. More than one fire zone may be provided in a given module or deck area, especially if the area is large. Each fire zone is provided with a dedicated supply riser and control valve which, when opened manually or automatically via the fire detection system, will commence water flow.

Deluge sprinkler systems use essentially the same type of sprinkler heads as closed-head sprinkler systems, except for the fact that the fusible element has not been provided, and the discharge orifice (usually nominal 1/2" or 5/8" in diameter) is open to the atmosphere. Either upright or pendant heads may be used, e.g., connected to the top of overhead branchlines pointing up, or to the bottom of overhead branchlines pointing down, depending on system design needs and preferences.

Water spray systems utilize especially designed discharge nozzles engineered to give predetermined spray patterns (full cone, hollow cone, etc.), droplet sizes (small drop

- large drop), velocities (high velocity, moderate velocity, etc.), and water densities (gpm/ft^2). They offer several advantages over conventional sprinkler heads:

- spray nozzles can be directionally aimed to provide a uniform spray over equipment surfaces, structural steel elements, and high fire risk areas in accordance with field-installed configurations, accounting for obstructions, etc. This allows, for example, the protection of gas filled pressure vessels below their equator as well as above, or protection of cable trays from below with direct water impingement.

- small water droplets in high densities provide much more effective cooling of heat-exposed surfaces than do large droplets of equal specific flow rate. Because water is used more efficiently, there is also less runoff and lower demands placed on the deck drains. This also reduces the risk of spreading burning crude via floating it on water runoff.

- heavy crudes and low vapor pressure combustible liquid spill fires can be extinguished using water sprays systems by cooling the surface to below its flashpoint, depletion of O_2 in the combustion zone due to steam production, via emulsification of some liquids, or by dilution of water-miscible flammable liquids such as methanol or ethylene glycol.

- fire intensity control is more effective using small droplets, even if extinguishment is not possible, by reduction of the fuel's specific mass burning rate (regression rate) due to surface cooling and reduced levels of incident heat flux feedback to the burning pool, as correlated by Thomas.[14]

$$\frac{H}{D} = 42\left[\frac{\dot{m}''}{\rho_{\bullet}\sqrt{gD}}\right]^{0.61} \qquad \text{(eq. 9-1)}$$

where H = flame height

D = pool diameter

$\dot{m}''$ = mass burning rate per unit pool area

ρ_a = ambient air density

Fixed water spray systems afford protection for large areas by discharging water through open-head spray nozzles that have been engineered to provide a specific water discharge density (gpm/ft.^{2}) over the protected piece of equipment, structural assembly, or overall area being protected. Their design is often based on the requirements of NFPA No. 15, *Water Spray Fixed Systems.* If properly designed, installed and maintained, fixed water spray systems can provide a high degree of protection for production platforms. And, as already noted, OCS Orders require their installation in enclosed well-bay areas in which hydrocarbon vapors may accumulate.

Fixed water spray and deluge sprinkler systems are sometimes designed for manual actuation, although most system design criteria calls for automatic operation with manual actuation capability. Some operators, however, based on past experience with false trips and perceived emergency response needs, may select to rely on manual operation on normally occupied platforms. FLAIM considers the means of system actuation to be an important risk factor, favoring automatic over manual means.

Fixed water spray systems, including deluge sprinkler systems, suffer from two distinct disadvantages when installed on offshore production platforms. They are usually very difficult to properly test and maintain, and they are subject to explosion damage from blast waves and impacts.

Sea water fire-fighting systems present a basic dilemma to platform operators regarding functional testing. In order to ensure proper operation, water spray systems should be routinely tested by flowing water through the system to locate blocked branch lines and clogged nozzles; nozzle plugging is perhaps the most frequently reoccurring problem in sea water spray systems. However, sea water promotes topsides equipment and facility corrosion.

For example using sea water for utility washdown purposes is generally avoided insofar as possible because such practices can shorten equipment service-life and decrease platform reliability. Fresh water is seldom available in sufficient quantities to allow a follow-up rinsing of large process areas protected by water sprays. Further, some operators are understandably reluctant to "unnecessarily" wet-down some types of equipment, such as hot ICEs, turbines, and compressors or explosion proof electrical enclosures (which are not waterproof by design) unless absolutely necessary, e.g., in the event of an actual fire; and, as already mentioned, these operators may have chosen a manually actuated water spray system out of concern for potential production disruptions and equipment damage.

Another associated reliability problem is the tendency of open-head spray nozzles connected to small diameter piping, e.g., 3/4" or 1" branch lines, to rapidly become plugged with salt deposits, pipe scale, and corrodants. Flushing the system out with fresh water is not always feasible, and it is frequently difficult to completely drain all sections of pipe after use. Consequently, it is not uncommon that clogged nozzles become part of the normal state of operations rather than the exception, and can significantly impact the level of platform fire preparedness.

Small diameter piping is also more apt to be damaged by explosion effects. The mechanical strength of small (threaded or brazed) connections can be exceeded by dynamic blast loads or by differential motion of bulkhead walls and structural members upon which the lines are secured. This can be a particular problem at points of pipe support and piping penetration, where induced pipe restraints and bulkhead motion can shear-off intervening pipe runs. Small diameter piping systems are also more susceptible to damage from projectile impact and shrapnel.

The importance of accounting for blast loads in the design of both bulkheads (fire & blast walls) and piping systems is now generally recognized following the Piper Alpha disaster.[15, 16, 17] However, older platforms are most likely based on designs with little or no account taken of blast effects dynamics and its potential consequences.

Enclosed well-bays areas subject to possible gas accumulation, e.g., those required by OCS Order to have spray systems, are, as evidenced by OCS's mandate, recognized to be at higher risk -- due to the possibility of vapor accumulation and subsequent ignition, e.g., at higher risk due to the possibility of an explosion. While perhaps this seems self-evident, the correlation for the need to design water spray systems with some added degree of explosion resistance was often overlooked in the past. There are examples, however, where explosion resistance was recognized in initial design development. For example, as early as 1971 Shell Oil platforms[18] in the Cook Inlet were designed to eliminate small branch connections by installing spray nozzles directly on larger size bulk distribution piping, e.g., two inch and larger all welded pipe. Designers also recognized the importance of providing rugged pipe hangars connected directly to main structural steel members for increased blast resistance.

Fixed water spray systems are currently being studied as a means of actively mitigating explosion blast overpressures and possibly suppressing explosions before ignition. The Steel Construction Institute is now commencing Phase II of the Topsides Fire and Blast Joint Industry Research Project in which large scale testing of this and other fire and blast mitigating techniques will be examined.[19]

The application of water spray systems for wellhead protection dates to the mid-1970's in pioneering work performed by Achenbach, Bourne and Ayers[20] of Continental Oil Company. This work sought to mitigate the vulnerability of pressurized bolted wellhead flanges (equipped with then standard B-7 bolting in accordance with API specifications) to leakage from short periods of fire exposure. Current API specifications include fire testing criteria for wellhead components largely due to recognition of this problem (see § 5.2.2.7 for further information).

Work by Gore, Evans, Pfenning,[21] et al. has examined the feasibility of using water spray systems to extinguish wellhead fires resulting from blowouts. Large scale test work on blowout suppression using water sprays was initiated in the mid-1980s (pre-Piper Alpha) by Dr. Dwight Pfenning,[22] with whom the author of this present work has collaborated with on several occasions regarding the modeling of hydrocarbon fueled pool and jet fires.

Despite promising test results favoring fixed water spray systems for both explosion mitigation and wellhead fire suppression, pragmatic limitations of system maintenance and testing need further innovative thinking. One approach deserving further attention is the use of a few large capacity - high velocity discharge nozzles in place of conventional designs that depend on evenly spaced arrays of small diameter spray nozzles to achieve general area coverage. One major oil company has adopted a policy of protecting CIHH equipment using fixed water spray systems employing firewater monitor-type spray nozzles located above and around the equipment. This approach avoids the drawbacks of small diameter piping and small orifice spray nozzles, and allows nozzles to be routinely replaced and returned to the workshop for inspection, cleaning, and testing. Piping can be arranged to permit functional testing and system flushing without the need to discharge water over platform equipment.

Fixed automatic water spray systems have also been adapted for protecting helidecks. One system uses pop-up spray nozzles, driven by hydraulic pressure much akin to the common lawn pop-up sprinkler. In the event of a helicopter crash or fuel spill fire, automatic fire detectors actuate the water control valve and the deck-mounted open nozzle spray head extend upward from their normal recessed position and discharge water or an aqueous solution of fire-fighting foam, e.g., AFFF. The manufacturer claims that the system is "almost maintenance free."[23]

Another helideck fire protection system utilizes heavy gauge steel surface grating suspended about a deck plate to provide for immediate fuel drainage. The grating acts to reduce fire intensity in the event of an ignition by absorbing heat and breaking up the flame front, somewhat like a conventional sintered flame arrester. So-called wick-type drainage (trench) covers are a recognized means of flammable liquid spill fire control that have long been used in both indoor and outdoor onshore hydrocarbon handling areas.[24] The helideck grating system is supported by foam distributing pipes which discharge fire-fighting foam between the grating and underneath deckplate in order to suppress fuel fires. One such helideck system (SAFEDECK™) that has been used on several North Sea platforms received the "Meritorious Award for Engineering Innovation" from Petroleum Engineer International at the 1980 Offshore Technology Conference.[25]

Conventional wet pipe sprinkler systems provide a reliable means of protection for areas in which ordinary combustible materials may be used or stored, e.g., the crew quarters, storage rooms, food lockers, etc. They also afford protection for important pieces of equipment that would not otherwise be protected with water spray/deluge systems, e.g., fire pump rooms and machinery areas. Wet pipe sprinkler systems and associate alarm devices should be designed in accordance with NFPA Standard No. 13, and inspected, tested and maintained in accordance with NFPA 13A.[26]

9.1.1.5 Fire Fighting Foam Systems

Fire fighting foam is effective in both crash rescue scenarios, such as in helideck systems described above, as well as for securing flammable liquid pool fire scenarios. There are a number of different foam formulations as well as form application systems that are in common use offshore.

Foam hose line stations provide a ready to use manual means for rapidly controlling pool fires as well as securing spills of volatile fuels that have not ignited. The foam blanket acts to suppress radiant heat feedback to the fire and reduce burning intensity, while depleting the supply of combustion air and effecting extinguishment. Individual water-foam hose line stations typically use fixed eductors (venturi devices) to proportion foam concentrate and water in the correct proportions. Some hose nozzles are especially designed with eductor ports to facilitate form proportioning directly from portable foam containers. Hose stations may also be supplied with foam concentrate under pressure via a foam concentrate distribution system connected to a main storage supply tank. Either pumps or water pressure (bladder tanks) may be employed to convey foam concentrate to user, e.g., the hose stations, monitors, or fixed systems.

Most fixed water spray systems can be converted to discharge low expansion non aspirated foam solution without extensive modifications. Adding foam has the advantage of enabling water spray systems to not only control fire intensity and cool exposed equipment and structural members, but also to achieve extinguishment of fires involving low flash point liquids. However, general area coverage using foam is not normally provided except in areas where there is a likelihood of frequent spill fires, such as in barrel filling and transfer operations.

Flammable liquid storage tanks are frequently provided with fixed fire fighting foam systems. These may be either subsurface injection type systems or based on the use of shell mounted foam chambers, depending on the size and design of the storage tank and the characteristics of the liquid being stored. If flammable and/or combustible liquid storage is provided on a platform, FLAIM asks about the provisions of a fixed storage tank foam system.

Foam is not effective on pressure fed fires, nor is it capable of extinguishing fires involving highly volatile fuels such as liquefied petroleum gas. In order to effectively cope with these types of fire scenarios, platform fire fighting provisions must include dry chemical and gaseous extinguishing agents. These are addresses in § **9.1.2.** On gas production platforms with little or no condensate production, provisions for fire-fighting foam may be unwarranted. However, if compressor lube oil reservoir fires or helicopter crash incidents are a credible fire risk scenario, then provision of fire fighting foam capability should be considered. FLAIM asks if fire fighting foam systems are provided and seeks to assess their adequacy relevant to fire fighting needs.

9.1.2 Fixed and Portable Chemical Fire Suppression Systems

The two primary types of non-aqueous chemical fire suppression agents utilized offshore, i.e., other than fire fighting foam concentrates, are dry chemical and gaseous agents. Both agents are effective in suppressing flammable liquid and gas fires, depending on the circumstances, as well as electrical fires. Both agents can be used in automatic fixed systems for general area protection and be locally applied using portable equipment or hose hand-lines.

9.1.2.1 Gaseous Agents

Gaseous agents are most suitable for protecting enclosures, such as enclosed gas compression modules or control room modules. Fixed "total-flooding" systems using Halon 1301 (bromotrifluoromethane) or carbon dioxide (CO_2) are designed to suppress fires throughout any area within an enclosure. Carbon dioxide systems require much higher concentrations of gas to effect extinguishment (about 40-50 mol %) than does Halon 1301 (5-6 mole %) due to different extinguishing mechanisms. Whereas CO_2 suppresses fires by oxygen depletion, Halon 1301 accomplishes its task by directly reacting with the combustion process and breaking the chain reaction. It is for this reason that Halon 1301 is not considered immediately dangerous to life and health, whereas CO_2 discharge must first be preceded by a signal in order to allow personnel evacuation from the area to avoid asphyxiation.

Commercial development of Halon 1301 grew out of military applications for the protection of aircraft engine nacelles. During the 1950 -1960 time period it was used to on Lockheed Constellations and Douglas DC-7s for engine fire suppression. In the mid to late 1960's DuPont developmental work led to widespread commercial applications of Halon 1301. Eventually every commercial aircraft built in the U.S. employed Halon 1301.[27] Due to its effectiveness at low concentrations and life safety attributes, Halon 1301 became the gaseous extinguishing agent of choice both onshore and offshore for a variety of hazards.

Halon 1301 is one of several halogen extinguishing agents, including the lower vapor pressure Halon 1211, bromochlorodifluoromethane, which has been frequently used for local applications. In 1966 the National Fire Protection Association organized a Technical Committee on Halogenated Fire Extinguishing Agents and Systems. This led to the development of NFPA Standard No. 12A (for Halon 1301) which was approved in 1970, and Standard 12B (for Halon 1211) which was approved two years later.[28] These are the only two NFPA recognized fire suppression agents in the Halogenated hydrocarbon family of chemicals.

Halon 1301 is frequently used to protection important electronic/electrical equipment such as found in control rooms, electrical equipment rooms and motor control centers, and oil and gas handling facilities. Its first major application in this regard was for the protection of large, totally enclosed oil and gas production modules on the North Slope of Alaska,[29] as well as in all of the Alaskan pipeline pumping stations.

Halon 1301 and 1211 have been frequently used offshore for many applications, such as protection of combustion gas turbines, control room protection, and total flooding of enclosed processing and pumping modules. Halon fire suppression systems are particularly well suited for Arctic environments where the use of water becomes problematic due to low temperature induced freezing problems.

The use of gaseous extinguishing agents for platform protection has been reviewed by Echternacht[30] and will not be repeated here since world-wide commercial Halon production is presently scheduled to be phased-out by 1994[31] due to its deleterious environmental effects, e.g., contributing to depletion of the ozone layer.

The phase out of Halon fire suppression agents is cause for concern to many offshore operators. There is currently an intensive effort to find suitable environmental-friendly substitute agents the have sufficiently similar characteristics to Halon 1301 so as to permit direct substitution with little or no modification of discharge system hardware. To date, a number of substitute agents are being proposed by various manufacturers. One such agent is heptafluoropropane-based, marketed by Great Lakes Chemical Company as "FM-200." The 3M Company, makers of Light-Water brand aqueous film forming fire fighting foam (AFFF), is also offering fluorocarbon substitutes for both Halon 1211 and 1301 -- PFC-614 (C_6F_{14}) and PFC-410 (C_4F_{10}) respectively; and Ansul, makers of Purple K (discussed below), is marketing a substitute, called INERGEN, composed entirely of unspecified naturally occurring gases. However, the effectiveness of such agents relative to their Halon counterparts is open to debate subject to further testing and large scale field trials.

In the interim, there is a movement to form a "National Halon Bank." Called the United States Halon Bank Management Program, the proposal calls for the formation of the "Halon Recycling Corporation (HRC),"[32] a not-for-profit corporation that would facilitate transfers of recycled Halon to meet critical fire protection needs on a national basis. It is proposed that his would be accomplished by establishing an *Essential Use Review Committee* for managing transfers between contributors and consumers of recyclable Halons. Sustaining members in HRC are now being solicited by the Halon Alternatives Research Corporation for a supporting contribution of $5000.00.

9.1.2.2 Dry Chemical Agents

Dry chemical agents are extremely effective in rapidly extinguishing flammable and combustible liquid pool fires as well as pressure fed liquid and gas fires. The can be directly applied (local application) to a fire using portable equipment, e.g., small and large (wheeled) fire extinguishers, from hose hand-line systems, via fixed skid-mounted dry chemical monitors, or by total flooding an enclosure from fixed overhead piping systems.

The agent of choice in the oil and gas industry is potassium bicarbonate based dry chemical, known commonly as "Purple K" due to the purple tone the dry chemical cloud takes on when discharged into the combustion zone. However, sodium bicarbonate based chemicals and so-called multipurpose chemicals based on monoammonium phosphate formulations (also effective on Class A fires, e.g., ordinary combustibles) are also frequently used in the industry.

Dry chemical agents, while extremely effective extinguishants, provide no protection against reignition of the fuel after extinguishment. If a fire has had sufficient time to heat surrounding exposures, such as structural steel members, process piping, etc., hot metal surfaces can cause rapid reignition of the fuel source making long-term extinguishment difficult. This weakness led to modification of dry chemical the formulations in order to permit use with aqueous fire-fight foam without loss of effectiveness. Most dry chemical formulations available today are foam-compatible to permit dual agent application.

The design of dry chemical extinguishing systems is regulated by NFPA's Standard No. 17, *Standard for Dry Chemical Extinguishing Systems*, which was first published in 1957.[33] This standard addresses the specific design requirements for fixed systems and hand hose line systems. Fixed systems are usually engineered to meet the specific need of the application, while hand hose line systems are often pre-engineered skid-mounted "packaged" units that need no further design.

Portable dry chemical fire extinguishers are covered by NFPA Standard No. 10, *Standard for the Installation, Maintenance, and Use of portable Fire Extinguishers.* The minimum requirements for the number, placement, and rating of portable and semi-portable fire extinguishers is specified by U.S. Coast Guard regulations in Title 33 of the Code of Federal Regulations, Subchapter N, *Outer continental Shelf Activities*, Part 145.

Oil and Gas production platforms are typically very reliant on dry chemical agents for fire control, especially where high pressure gas fires are a significant risk. OCS Orders,[34] in fact, make allowance for a fire-fighting system using chemicals in lieu of firewater systems subject to approval by the MMS District Supervisor.

Large fixed total-flooding dry chemical systems have been used to protect well-bays and gas compression modules. For example, during the early 1970's, the author of this present work, working in conjunction with Earl & Wright (offshore engineering contractors) and the Ansul Company (manufacturers of Purple K), participated in the design of the world's largest fixed dry chemical system total flooding systems (four ton capacity) installed up to that time for protecting wellhead and gas treating areas of the Maui A[35] gas condensate platform located in New Plymouth, New Zealand.

Most platforms rely on a combination of skid-mounted hose handline units and portable units for platform protection. Dry chemical is generally employed as the first line of fire attack, used to "knock-down" developing fires. It is often employed in combination with fire fighting foam in unitized so-called twin or dual-agent skid mounted units. Such systems provide the user with two hand-lines -- one for dry chemical application and the other for foam application.

Dry chemical systems are also frequently used to extinguish platform vent stack fires and to protect galley cooking surfaces and stove hoods in the crew quarters.

A recent development in dry chemical application technology is worthy of mention. A new patented "Aqua-Chem" nozzle developed by Williams Fire & Hazard

Control, Inc., world famous marine fire-fighting experts formerly associated with "Boots & Coots," combines water and dry chemical discharge into a single nozzle. The author and Professor R.B. Williamson have meet with a principal of Williams Fire & Hazard Control to initially assess this new innovation. The Aqua-Chem nozzle appears to offer an impressive multidimensional fire fighting capability; combining water/foam stream discharge with pulses of dry chemical discharge, it can effectively extinguish high pressure flange fires at much greater distances than hand-held extinguishers while at the same time afford a degree of cooling to exposures.

FLAIM asks about the provision of dry chemical fire-fighting equipment and systems onboard the platform. RIRA seeks to assess both the adequacy of provided fire-fighting capability, and the reliability of in place equipment and systems.

9.1.3 Fire Detection Systems

Detection of fire at its initiation is critically important to minimizing escalation by controlling fuel release, cooling exposures, and effecting extinguishment as rapidly as possible. As already discussed, most fires other than major well blowouts, result from poorly preplanned and supervised maintenance and repair activities (MARW), usually involving the release of crude oil of gas (a LOC event) at a time when welding or other abnormal ignition sources are present. Consequently, such fires are usually reported by the personnel engaged in the work activity without reliance on fire detection systems.

Automatic fire detection systems are nevertheless considered a vitally important element of a platform's risk reduction program. All areas of a platform in which process equipment and piping is installed, or in which combustible materials may be temporarily or routinely stored, should be provided with some form of automatic fire detection. OCS Orders call for flame, heat, or smoke sensors in all enclosed classified areas.

Compliance with API RP-14C,[36] as mandated by OCS Orders, requires the provision of a method for automatically detecting fire as part of the surface safety system. RP 14C notes that:

> *"A pneumatic line containing strategically located fusible elements (Fire Loop) provides a reliable method of detecting fires and is widely used for this purpose. Fusible elements are normally metallic plugs that melt at a predetermined*

temperature, or a section of fusible synthetic tubing.... In addition to pneumatic fire loop systems, various electrical fire detection devices (flame, thermal, and smoke) are commonly used on offshore production platforms."

Table C1 of RP 14C, *Guidelines for Fusible Plug Installations*, indicated the recommended location and number of fusible plugs required for protecting topsides equipment, including wellheads, headers, pressure vessels, storage tanks, fired heaters, pumps, compressors and engines. For example, each wellhead (Christmas tree) should be provided with at least one fusible plug, and each 10 foot section of header piping should have no fewer than one fusible plug, or be protected by a continuous run of fusible pneumatic tubing. A typical platform pneumatic fire loop arrangement is shown in § 5.2.2.7

The pneumatic fire loop, which operates at control line pressures of about 35 psig via the platform instrument air system, supplies air pressure to one side of pneumatically operated pilot valves. The pilot valve is a fail safe spring-return normally closed valve that is held open by control line pressure, as is the SSV. The valve has a high pressure port that, when open, allows high pressure surface safety valve actuator air (about 250 psig) to maintain the SSV in an open position. Any disruption to the low pressure control line pressure, such as melting of a fusible plug or manual actuation of an ESD station (vent valve) will cause the pilot valve to close and depressure the SSV actuator, which in turn closes and shuts in the wellhead.

Pneumatic fire loops using fusible plugs are also used to automatically actuate fire protection systems such as water spray/deluge systems. These devices, while seemingly somewhat archaic in the 1990's, nevertheless provide a simple, reliable, and effective means of initiating platform shutdowns and fire protection systems.

Pneumatic fire loops are often supplemented with other types of fire detection devices in order to enhance response time. Productions of combustion (POC) smoke detectors are used in crew quarters and control room/electrical rooms to detect fires involving ordinary combustible materials and fires of an electrical origin. POC smoke detectors are often used to actuate Halon 1301 fire protection systems; in this application they are commonly cross-zoned so as to require two independent alarm indications prior to initiating agent discharge.

Smoke detectors react to fires in an incipient stage and therefore are an effective means of mitigating life safety fire risk. Platform accommodation areas should be provided with smoke detectors designed to sound personnel alarms and initiate warnings at the control room. FLAIM asks if UL listed or FM approved POC smoke detectors designed in accordance with NFPA 72 & 72E[37] have been provided on the platform in appropriate areas.

Optical fire detection systems, such as those using ultra-violet (UV), infra-red (IR), or a combination of UV-IR sensors, have improved greatly during the past twenty years. Many of the earlier problems plaguing these types of detectors, such as false alarms from lightning, welding, and sunlight reflected from the sea, have been successfully eliminated. Modern optical fire detectors offer the advantage of near instantaneous fire detection on offshore platforms. This is due to the fact that fires involving released hydrocarbons are immediately large -- in accordance with the amount of fuel released. Strategically placed and well maintained optical fire detectors will immediately respond to such fire scenarios.

Perhaps the most significant disadvantage to UV fire detectors in the past, other than spurious signals, has been their susceptibility to blinding from accumulated oil coatings on the lens. Even an invisible coating of oil can sufficiently attenuate UV reception to cause non responsiveness. IR detectors do not suffer from this effect; however, their tendency to alarm from any high source of IR radiation, such as hot exhaust surfaces, greatly limited their application offshore. Both of these problems have largely been solved through a combination of selective frequency monitoring and built in self-checking features. As a result, optical fire detectors are now widely used in both onshore and offshore petroleum operations, as well as in a variety of military applications, commercial aviation, and industrial manufacturers.

FLAIM asks if optical fire detectors are currently employed on the platform and where they are installed. FLAIM also considers how they are used, e.g., for alarm only, actuation of fire suppression systems, and/or for platform shutdown. For example, if optical fire detectors are located in the well-bay, FLAIM asks if they initiate closure of the subsurface safety valves in addition to SSV's.

Heat actuated devices (HADs) include fusible plugs, conventional sprinkler heads, and electrically operated heat detectors. There are two types of electrically powered heat detectors commonly used offshore, rate-of-rise detectors and fixed temperature rate compensated detectors. Electrical operated heat detectors are appropriate to use to protect areas in which POC smoke detectors may have a tendency to false alarm due to the presence of combustion products, such as in areas where engine driven equipment is located. Rate-of-rise detectors tend to be more prone to false alarms than rate compensated devices; however, both kinds of heat detectors will provide reliable fire detection when used in the appropriate environment. FLAIM asks if heat detectors are used on the platform and how reliable they have proven to be.

9.1.4 Combustible Gas Detection Systems

OCS Orders require that combustible gas detectors be installed in all inadequately ventilated, enclosed classified areas, e.g., Class I Division 1 locations. [Adequate ventilation,[38] also defined by MMS, is discussed in § 9.6.1, Vapor Control Provisions]. As previously discussed accumulation of flammable gases and vapors within platform enclosures is a significant risk factor and accounts for the much higher loss rate experienced by North Sea platforms compared to those in the GOM. Combustible gas detection systems permit rapid detection of gas accumulations and alert operators to developing equipment and pipe leaks. Early warning of gas accumulations also permit operators to initiate corrective actions such as de-energizing potential electrical ignition sources, isolating the source of the process leak, and depressuring equipment.

Some platforms handling large inventories of high pressure gas have elected to initiate actuation of process area water spray/deluge systems in the event that one or more gas sensors indicate the high alarm level set-point has been exceeded -- usually set 60% of the lower flammable limit (LFL) of methane (e.g., at 60% of 5 mol % CH_4 in air, or 30, 000 ppm by volume). Some operators of enclosed modules provide mechanical ventilation with two speed fans. In the event of a low level gas sensor alarm (e.g., usually 20% of the LFL of the gas being monitored), the air handling system automatically goes into an emergency ventilation mode to increase module exhaust rates. Should any two gas sensors reach the high alarm set-point, all ventilation is shutdown, the module process system is isolated using automatic MOVs (motor operated valves), and the module is totally flooded with Halon 1301 at 7.7% concentration -- sufficient to inert the atmosphere in the presence of methane.

There are a number of different designs of gas sensors commercially available, including the Whetstone bridge-based catalytic sensor, the semiconductor sensor, the electrochemical cell sensor, infrared sensors, and laser detection sensors. Most offshore facilities employ either the well known catalytic sensor or the semiconductor sensor. An important consideration in determining sensor selection is the device's long-term stability, e.g., proneness to drift from calibration, and its susceptibility to poisoning by atmospheric contaminants, such as silicon vapors, Halogenated compounds, etc. In addition, electronics used in the control equipment, such as high-gain operational amplifiers, may be sensitive to electromagnetic interference (EMI), and especially radio frequency interference (RFI),[39] resulting in false alarms and, in some cases, unwanted operations of fire suppression systems, e.g., Halon "dumps."

Guidance for the selection and design of gas detection systems is presented in API RP 14F, and ISA S12.13, Parts I & II.[40]

FLAIM accounts for three general risk reduction aspects in regard to gas detection systems: 1) sensor location, 2) sensor function, and 3) system testing and reliability. Listed below in **Table 9-1** are the requirements established by one major offshore operator for the location and number of gas detectors for warm-water offshore production platforms.

Table 9-1

Typical Requirements for Combustible Gas Sensors

AREA	Min. #	Function
Drilling Deck	1	Low and High Alarm Only
Mud Mixing	2	Alarm; any 2 detectors in High Alarm cause area process shutdown and open area water spray/deluge valve and start fire pumps
Well-bay (inadequately ventilated)	2	Alarm; any 2 detectors in High Alarm cause area total production shutdown, close all well wing valves, start fire pumps, and open area water spray/deluge valve
Production Area (inadq. Ventilated)	2	Alarm; any 2 detectors in High Alarm cause area process shutdown and open area water spray/deluge valve and start fire pumps
Produced Water Treating (Inadequately Ventilated)	2	Alarm; any 2 detectors in High Alarm cause area process shutdown and open area water spray/deluge valve and start fire pumps
Gas Compression and Treating	2	Alarm; any 2 detectors in High Alarm cause area process shutdown
Turbine Enclosures	2	Alarm; any 2 detectors in High Alarm cause area process shutdown, isolation of fuel supply, close ventilation dampers, and discharge Halon system
Turbine combustion air	2	Alarm; any 2 detectors in High Alarm cause area process shutdown, isolation of fuel by closing shutdown valves
Injection Water Treating (Inadequately Ventilated)	2	Alarm; any 2 detectors in High Alarm cause area process shutdown,
Fired Glycol Regenerator	2	Alarm; any 2 detectors in High Alarm cause area process shutdown, isolation of fuel by closing shutdown valves
Offices, shops or Bulk Storage	1	Alarm; single detector at High Alarm cause shutdown of all ventilation, air conditioning or heating, and closes all dampers, trips electrical supply if all electrical equipment does not meet Division 1
Quarters Air Conditioning and Ventilation Inlet	2	Alarm; single detector at High Alarm cause shutdown of air conditioning and ventilation system heating elements, two detectors at High Alarm closes dampers and shut down of all fans.
Gas Compressors and Gas Fueled Internal Combustion Engines	1 per unit plus add 1 more for each 3 units or less	Alarm; area process shutdown, on any single detector in High alarm and release of Halon; or with any two adjacent detectors in alarm, provided that each engine compressor set is provided with a minimum of 2 gas sensors.

Source: from company proprietary information of a major offshore operator - for illustration only

FLAIM asks if gas sensors have been installed in any inadequately ventilated process area on the platform, e.g., compliance with OCS Orders. It also asks the user to identify each area on the platform in which combustible gas sensors have and have not been installed, and the corresponding ventilation descriptor identified, e.g. open to atmosphere on all sides and above, open on three sides but below deck, etc. For each of the areas provided with sensors, FLAIM asks what function is performed at the high alarm setpoint. Finally, FLAIM asks about system maintenance, testing, calibration frequency and historical operating experience with regards to system reliability.

9.1.5. Toxic Gas Detection Systems

Special rules apply to platform operations handling sour crudes and gases, including the provision of hydrogen sulfide gas detection equipment. The first version of FLAIM has been developed based on the assumption that the absence of H_2S has been confirmed in the zones of production from which the platform is producing. This was done for reasons of simplification; recognizing that many platforms handle sour crudes and gases. FLAIM-TWO will include a component for assessing H_2S risk mitigation systems and equipment, including detection and alarm systems.

9.1.6 Alarm and Communication Systems

Platform alarm and communication systems are vital to offshore platform operations and personnel safety. Both onboard and off-platform communications must be effective during emergencies to communicate platform status and coordinate response measures. Platform fire and gas detection, process control systems, and emergency shutdown systems may employ a hierarchical arrangement of automatic and manual warn and alarm signaling depending on the nature of the event and its immediacy.

Platform alarm signals should be limited to a few as reasonably feasible in order to avoid confusion during emergency situations; however, this may be surprisingly difficult to accomplish with less than six different audible signals.

Automatic fire detectors and manual fire alarm stations should have a distinctive signal from all others. However, it may be deemed appropriate to distinguish between a fire in the crew quarters or other non-process areas from process-critical areas such as the wellbay and gas compression areas. Similarly, combustible gas detection should normally have a distinctive audible signal, further subdivided in low level alarms and high level alarms. Other alarm signals may range from operation of the surface safety valves (e.g., general topsides process shutdown) to critical process operating alarms, such as high level alarm in compressor suction knockout drums, indication of fire suppression system discharge, fire pump running signals, and loss of critical utilities, such as instrument air supply.

Many process alarms are locally alarmed in the control room or other normally attended location, and do not require general platform alarm. This may also be true of some fire alarms, such as a smoke detector alarm in the crews quarters that may sound the fire alarm bell therein or send a prealarm signal to the control center to allow operator intervention without unduly awakening the entire contingency of sleeping personnel. However, if the operator is routinely in the processing area performing various duties, local audible alarms may be warranted.

Audible signal (tone) generators may be employed to create distinctive warning signals while limiting the number of individual alarm signaling devices that may be necessary to provide and maintain. Such units are often combined with platform paging and hand-set communication systems that allow direct communication between various areas on the platform and general announcements to be made for advising all personnel of developing situations.

Voice communications between helicopters, marine vessels and shoreside pipeline receiving terminals and control centers is also vital to emergency response preparedness. Off-platform communications make use of a variety of marine communication networks, as well as microwave systems for data and alarm transmittal, e.g., SCADA systems (Supervisory Control and Data Acquisition systems).

All manned production platforms are required by U.S. Coast Guard regulations[41] to be provided with a general alarm system that produces an audible signal in all parts of the structure. Further, the regulations require that the warning signal used to advise personnel to go to platform emergency staging areas (emergency stations) shall be an intermittent signal over the general alarm system for not less than 10 seconds duration, e.g. all-hands to emergency (battle) stations.

Emergency *station bills* (sometimes known as duty rosters or muster lists) must be posted to communicate the special duties and duty stations of each member of crew during an emergency.

In the event it is deemed prudent to abandon the platform due to an uncontrollable emergency, Coast Guard regulations specify that this be indicated by a continuously sounding audible signal on the general alarm system. The regulations also require that general alarm bell switches and bells are required to be painted red and properly identified. As discussed in § 9.3 Emergency Shutdown (ESD) Systems, platform abandonment is usually a last resort and coincides with or shortly follows a complete platform shutdown, e.g., a manually activated ESD (Level IV) shutdown. The placement of "Abandon Platform" manual stations may parallel the placement of manual ESD control stations, as described by API RP 14C.

9.1.7 Emergency Power and Lighting

Platform safety systems and other critical loads should be provided with a source of standby power designed to assume full load demand with minimum interruptions, distortions, spikes, or dips in the supply. Many electrically operated safety systems are designed for direct current (24 VDC) operations and provided with on-line battery backup with trickle charges to maintain voltage levels. Inverters for powering alternating current (AC) systems from direct current (DC) sources, e.g., DC to AC inverters, should generally be avoided in favor of DC-powered systems.

Platform battery rooms should be located in an electrically unclassified area of the platform, and provided with exhaust vents/ducts at ceiling level to remove hydrogen. A hydrogen gas detection system is also a recommended safety precaution, but cannot compensate for inadequate ventilation.

Uninterruptable power supplies (UPS) or emergency power supplies (EPS) are frequently used for fire and gas detection, emergency lighting, and other critical systems, arranged with AC to DC converters and automatic switchovers from normal utility power grids to alternative power supply with minimal distortions.

Larger emergency demand loads, such as for electrically driven standby fire pumps, are connected to the emergency generator bus. Depending on system design, several seconds to more than a minute may be required for the emergency generator to come up to speed and on line. During this time, other vital platform safety systems may be de-energized if no other means of backup power is provided. For this reason, battery backup of at least some safety systems, such as emergency lighting, is standard practice.

Interruption of some critical safety system circuits can cause unwanted results if circuits are designed as normally-energized (fail-safe) systems. For example, it would be undesirable for a power interruption or distortion in fire and gas detection circuitry to result in automatic discharge of platform Halon 1301 fire suppression systems, or simultaneous actuation of all platform water spray/deluge system valves. This is especially true in an emergency when, for example operations of too many water spray/deluge system valves could overload platform fire pumps and deplete system pressure and flow capacity.

Therefore, while many equipment and system shutdown circuits may include provisions for fail-safe operation, protective signaling circuits are normally supervised for trouble indication using a small supervisory current that is maintained in the circuit via an end-of-line (EOL) resistor. Discontinuities in the circuit, as may be caused by breaks, (open circuit) or grounds, give a trouble signal at the control module; however, in circuits employing contact closure devices, such as electrically operated manual fire alarm stations, supervised circuits may not be able to distinguish between a direct short and the operation of a circuit device.

Loss of safety system power supply should result in activation of visual or audible alarms in the control room. If bypasses are provided to permit system testing without initiating programmed responses, such as Halon dump, a "ring-back" feature should be included in system design so as to ensure that the system cannot be left in a bypass mode when testing is complete and the control unit is switched from the test mode back to normal service, e.g., if the bypass has not been restored, a warning indication is given.

Adequate platform lighting is required for operator safety and platform safety. Minimum recommended levels of illumination for safety are given in Table 7.2B of API RP-14F as follows:

Table 9-2
Minimum Lighting Levels

Area	Minimum Lighting Level (Foot-candles)
Stairways	2.0
Offices	1.0
Exterior Entrances	1.0
Compressor and Generator Rooms	5.0
Electrical Control Rooms	5.0

Area	Minimum Lighting Level (Foot-candles)
Lower Catwalks	2.0
Open Deck Areas	0.5

Source: API RP 14F, *Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms* (RP 14F), American Petroleum Institute, Third Edition, September, 1, 1991, p.46.

Platform crew quarters, personnel staging areas, egress routes, workshops, and other areas in which a loss of illumination could pose a danger to personnel should be equipped with standby (emergency) lighting systems. Some platform areas should be designed for uninterruptable lighting due to their criticality either during normal operations or in an emergency, e.g., the drill floor during drilling operations. In such areas, mercury vapor and metal halide lamps should be avoided or provided with backup lighting, such as fluorescent lamps, since they will not re-light immediately after a brief power outage.

Adequate lighting and audible signals, e.g., fog horns, are required to ensure platform safety with regard to shipping traffic. Navigational equipment and power requirements are specified by the U.S. Coast Guard regulations [ref.: 33 CFR Subchapter C, Part 67, Aids to Navigation, U.S. Code of Federal Regulations].

9.2 *EMERGENCY SHUTDOWN (ESD) SYSTEM*

The ESD system is defined by API RP 14C as a system of manual stations which, when activated, initiate platform shutdown, e.g., the shutting in of all process stations of a platform's production process and all support equipment for the process. Generically, however, the term emergency shutdown is used to describe various states of process system shutdown, ranging from the local shutdowns of process equipment, such as a compressor, and shutdown of an entire process train, to shutdown of all topsides operations, entire platform shutdowns including subsurface safety valves and riser valves and electrical power.

For example, Smith[42] used four levels of shutdowns to describe ESD priorities relevant to risk for typical GOM production platforms in the 1970's . The highest level of shut down, Level IV -- a complete platform shutdown, is manually initiated from ESD stations located at the helideck, exit stairways landings at each deck level, boat landings, at the center or each end of a bridge connecting two platforms, emergency evacuation stations, near the driller's console during drilling and workover operations, near the main exits of the crew quarters, and at other similar locations as needed to provide ESD access from all platform areas.[43]

A Level IV shutdown typically would close all surface and subsurface safety valves, depressures gaseous inventory to the flare, and de-energizes all power systems and equipment except for emergency services. The next step down is a Level III shutdown which could be activated either manually or automatically by platform fire detection devices. In this case, all surface safety valves close as in a Level IV shutdown, but the subsurface valves remain open unless the alarm is initiated from the wellbay. High pressure gas is flared and the main power supply buss de-energized; however, the main generators would not necessarily be shut down. Fire pumps may be automatically started independent of pressure control start signals.

A Level II, a general process shutdown, is correspondingly less comprehensive and may only close selected production header and pipeline valves to isolate one production train without depressuring the system or shutting in wells. This allows operators to quickly respond to upset conditions and restore normal operations without a major impact on production. A high liquid level in a compressor scrubber may initiate a Level II shutdown.

A level I shutdown is the least serious process shutdown and may involve individual pieces of process equipment, such as a compressor shutdown due to low lube oil pressure in the turbine. Level I shutdowns may also apply to systems that are considered auxiliary to the main process, such as water injection facilities.

In general, ESD systems consist of three components; 1) a detector or sensor which monitors normal conditions and detects the presence of an unsafe or abnormal situation, 2) a system of logic which responds in accordance with the inputted variables and transmits appropriate control signals, and 3) an actuating device or devices that respond to the initiated control signals by depressuring pneumatic, hydraulic or motor operated control valves, tripping motor control centers, shutting down rotating equipment drivers, and so forth.

A fundamental and controversial issue in the design of ESD systems (in general -- onshore and offshore) revolves around the issue of "fail-safe" design, e.g., should control circuits and systems be designed to operate normally energized or normally de-energized. Normally energized systems are considered truly fail-safe; loss of power (electrical, hydraulic, or air) will cause valves to close (or to open or remain in its last position, depending on what constitutes a safe failure mode), motors and engines to stop, and systems to power-down and depressurize. Normally de-energized systems, however, require the application of power to cause system shutdown, e.g., contact closure to provide power to close a motor operated valve.

Proponents of normally de-energized systems point out that normally energized ESD systems are vulnerable to unnecessary actuation caused by any number factors, such as power fluctuations, RFI, and even accidental contact/impact of control stations. This controversy was illustrated by API RP 550, Manual on Installation of Refinery Instruments and Control Systems, Part 1-- Process Instrumentation and Control, Section 13, Alarms and Protective Devices, (Third Edition) which contains the following admonition:

> *Care should be taken to ensure that voltage "dips" and momentary outages do not cause unwanted control or alarm action. This situation can be prevented by the use of normally de-energized circuits, or, in the case of normally energized circuits, the use of time delays or uninterruptable AC o DC power supplies. There is considerable controversy over the relative merits of each of these systems with opinions appearing to be about equally divided. Arguments favoring the normally energized systems emphasize that fail-safe characteristics of such a design; those in support of de-energized circuits stress the reduction of so-called nuisance shutdowns. Other factors (such as the likelihood of burnout for continuously energized coils in relays or solenoids, or the problems to be encountered with normally open sensor switches) must be considered. There is a wide variety of uninterruptable power supply systems available. Therefore a design that will ensure reliability and good performance must be carefully selected.*

Platform Level III and IV ESD systems are generally designed to be fail-safe; loss of pneumatic or hydraulic control line pressure allows spring operated normally closed surface or subsurface safety valves to return to their normally closed positions. Manual ESD stations are often control line pilot valves that vent system pressure and thereby initiate shutdown. Level I and Level II ESDs, e.g., process safety shutdown systems, may or may not be fail-safe designs.

The frequency of unwanted shutdowns in normally energized systems depends to a large degree on the quality of system components, materials, construction, preventative maintenance, and reliability of the power source. There is little argument that, in general, inadvertent system trips caused by wiring faults, power surges, and human factors are less likely to occur in normally de-energized shutdown circuits. If fail-safe designs are unreliable, there is a risk that operators may elect to perform unauthorized field modifications, such as jumpering shutdown switching circuits or "forcing-on" the appropriate input in a programmable logic controller to avoid unwanted trips. In a real emergency, such systems will not safely shutdown.

An additional concern arises in situations were frequent spurious equipment shutdowns cause equipment, such as fired heaters, to have to be frequently brought back on line. Loss data clearly shows that, in the case of fired heaters, most accidents involve human error during startup cycles. Unreliable fail-safe designs can actually lead to increasing the risk of accidents.

FLAIM seeks to determine the overall reliability of platform shutdown systems based on operating experience and testing/inspection reports as mandated by OCS Orders and RP 14C. A detailed analysis for RP 14C compliance is not presently included as a part of FLAIM's elements, but may be easily added by the user should this prove helpful.

9.3 *PRESSURE RELIEF AND VAPOR DEPRESSURING SYSTEMS*

As Arnold[44] has stated, the design of platform pressure relief and depressuring systems are not addressed in API RP 14C. Pressure relief valves are required by code (e.g. ASME boiler and Pressure Vessel code -- Section VIII) to be provided on pressure vessels; how their size has been determined, and how the relief header and emergency vent and flare system is designed is important to platform safety. In addition, platform ESD may require automatically depressuring process systems, e.g., process system blowdown to flare.

Analysis of the pressure-relieving system capacity of and evaluation of its ability to meet worst credible case scenarios requires a detailed review of design parameters, accurate as-built piping and instrument diagrams (P&ID) and equipment data sheets, and current information on process conditions. As platforms are modified and conditions change over the years, it is not unusual to find that the capacity of pressure relieving devices and relief headers has not been reviewed for adequacy, even though addition equipment may have been added or process operating conditions exceed the original design basis. FLAIM does not include a detailed analysis of pressure relief devices and systems; it does, however, seek to determine when such an analysis should be performed and to evaluate to what extent present provisions may be inadequate.

9.3.1 Pressure Relief Valves

Pressure relief valves (also sometimes pressure safety valves or PSVs)[45] are provided on pressurized equipment and piping systems in order to ensure that upset or abnormal conditions will not cause internal pressure to exceed maximum allowable working pressure design limits and vessel or pipe failure. There are potentially many causes of excess internal operating pressure that must be considered in the selection of relief valves, including external fire exposure. The basis for determining relief rates and relief valve size criteria as determined from an analysis of the various potential causes of overpressure depends to a large extent on good engineering judgment.[46] This includes the consideration of whether or not to consider operator response in determining maximum relieving conditions, e.g., limit relief capacity design based on operators responding and correcting the upset conditions within 10 to 30 minutes from initiation of the event.

When pressure vessels that contain liquid are exposed to fire, vapor is generated as heat is absorbed by the liquid. The rate of vapor generation changes with equilibrium conditions and increasing internal pressure. If the relief set pressure is below the critical pressure, liquids, such as crude oil which is a mixture of various components and boiling point factions, will boil off in accordance with their boiling point curve -- first liberating low boiling point vapors and than successively heavier and high temperature boiling point factions. During the pressure relieving process, vapor rates and vapor densities change with time; with the peak instantaneous relieving rate usually occurring near the critical temperature. If the rate of vapor generation is greater than the rated capacity of the relief valve, internal pressure may increase above the maximum safe pressure and temperature operating limits.

The heat input absorbed by a liquid-containing pressure vessel exposed to fire is generally estimated using a empirical relationship:[47]

$$Q = 21{,}000FA^{0.82} \qquad \text{(eq. 9-2)}$$

where F is an environmental factor[48] that accounts for vessel thermal insulation (F=1 for bare vessels, and between 0.075 to 0.3 for insulated vessels depending on its thermal qualities,
A is the total wetted surface area in square feet,
and Q is the total heat absorption to the wetted surface in BTU/hr.-ft.[2]

Using this relationship, the rate of vapor generation from boil-off (and the rate of vapor relief required) may be determined by dividing the Q by the latent heat of vaporization, assuming that the temperature and pressure conditions are below the critical point.[49] The maximum relief capacity required equals the equilibrium vaporization's rate under relief temperature and pressure conditions, recognizing that this changes with time as liquid composition changes during the boil-off process, and the latent heat may also change (decreasing with increasing temperature). If the relief valve setting is above the critical pressure then the relief capacity depends on the thermal expansion rate of the fluid, and the pressure vessel temperature will rise to the critical temperature of the fluid.

If a pressure vessel or pipe has little of no liquid, or is operating under conditions that require the relief set pressure to exceed critical conditions, then the pressure relief valve cannot effectively protect the vessel or pipe from failure. Heating of the pipe wall or pressure vessel shell to sufficiently high temperatures (above about 800°F) to cause creep rupture can occur within a few minutes if no liquid is present to absorb heat. This may also occur to the vapor space of process pressure vessels if the unwetted shell is impinged upon by jet fire plumes.

Of particular concern are vessels contain high vapor pressure liquids (above 40 psia @ 100°F), such as liquefied petroleum gas. Small "hot-spots" in the vapor space portion of fire-exposed pressure vessels may experience sufficient loss of tensile strength to form small tears. The sudden release of the high vapor pressure liquids can lead to auto-refrigeration and brittle (catastrophic) failure of the vessel shell. Should this occur, the now superheated liquid (at atmospheric pressure) undergoes flash vaporization and produces a tremendous vapor cloud/fire ball. This phenomena is generally referred to as a BLEVE -- boiling liquid expanding vapor explosion.[50]

Pressure relief valves cannot protect a vessel or pipe that becomes locally overheated; they can only prevent internal pressures from exceeding the accumulation pressure of the valve,[51] e.g.,. the allowable pressure increase above the maximum allowable working pressure of the vessel during discharge through the pressure relief valve. To protect pressure vessels from the risk of failure from local overheating and stress rupture, vapor depressuring systems should be provided (see § 9.3.3). However, some operators may choose to rely solely on the protection afforded by fixed water spray/deluge systems.

9.3.2 Relief and Vent Header Design Considerations

Determining the size and number of the relief header(s) -- the pipeline(s) that connects the discharge of relief valves to the emergency vent or platform flares, depends on many considerations, including the mechanical design of the relief valves, valve size and capacity requirements, operating pressures, the layout and configuration of the platform (number of vessels and process components within a single fire area), drainage provisions and fire protection provisions, etc. In addition, relief header design is often constrained by size and economic considerations.

The are three issues that FLAIM seeks to explore with regard to header design:

- is the header capacity adequate for the present as-built operating conditions
- is the header size based on balanced bellows-type relief valves and, if yes, have all relief valves been audited to meet this requirement
- are adequate liquid knock-out (scrubbing) facilities provide to prevent liquid carryover

It is not unusual to find that during the course of a platform's operating life new equipment items have been added to the process system and connected to the relief header. Environmental regulations restricting atmospheric discharge have also served to add more relief valve discharges and increase the potential relief header loads. This may have been done without a full review of the ramifications on relief system design capacity. In addition, changes in platform configuration may result in greater risk of more pressure vessels relieving simultaneously due to mutual fire exposure.

If the allowable relief header backpressure has been determined based on using balanced bellows-type relief valves, care must be taken to ensure that some pressure vessels are not equipped with conventional safety relief valves that have lower backpressure tolerance. If the platform does not have separate high pressure and low pressure relief headers, relief valve sizing must account for potential backpressure effects when vessels of different normal operating pressures are simultaneously relieving. Backpressure may also be increased as a result of two phase flow and liquid entrainment; if liquid flow or slug flow is possible from a vessel, the relief valve size and header must account for this.

Another problem is failure to account for maximum relief header operating temperatures that may be reasonably expected to occur during fire scenarios. High temperature gas/liquid discharged into a relief line can cause significant thermal stress. Relief headers must perform satisfactorily during fire relief scenarios; design operating temperatures based on the normal operating temperature of the relieved process fluids, rather than maximum anticipated fluid temperatures during fire conditions, can result in relief header designs with inadequate provisions for thermal expansion.

Liquid slugs can generate large hydraulic forces, e.g., hydraulic surge (hammer); piping must be designed to accommodate thermal expansion and slug flow under fire relief conditions. Liquid scrubbing facilities must be adequately sized to take large slugs of liquid without carryover to the flare, as required by OCS Orders.[52] This is especially important on platforms where production flowlines and headers are designed for maximum working pressures that are less than the maximum wellhead shut-in pressure, necessitating protection with a relief valve.

9.3.3 Vapor Depressuring Systems

Vapor depressuring systems can prevent catastrophic rupture of pressure vessels an piping exposed to fire by reducing internal pressure and corresponding stress levels in the material. They also serve to reduce the potential amount of fuel that is available to a fire and reduce the driving force in pressure fed fire scenarios. Depressuring system design criteria is suggested by API RP 521:

to provide adequate venting capacity to permit reduction of the vessel stress to a level at which stress rupture in not of immediate concern...this generally involves reduction the equipment pressure from initial conditions to a level equivalent to 50 percent of the vessel's design gage pressure within approximately 15 minutes.[53]

Kletz[54] points out however that while such general guidelines are useful, actual design criteria should have a theoretical basis, keeping in mind that the objective of depressuring is to prevent vessel failure from stress rupture under fire exposure conditions. In the case of some pressure vessels, this may require depressuring to as low as twenty percent of the design pressure, depending of the type of steel and the wall thickness, and may occur as quickly as ten minutes.

The provision of vapor depressuring systems may vary greatly from one platform to another. Some operators may chose to limit such systems to vessels operating above a specified pressure level, such as 250 psig, while other company policies have determined that all equipment containing light hydrocarbons should be depressured to either 100 psig or 50% of their normal operating pressure, which ever is lower. If, however, the normal operating pressure of a liquid containing pressure vessel is several hundred pounds per square inch, rapidly depressuring it to 100 psig may not be feasible due to excessive liquid carryover. In such cases, thermal insulation, fireproofing, or water spray systems may prove to be an acceptable means of mitigating the risk.

OCS Orders require the depressuring systems in some circumstances. For example, depressuring (blowdown) valves are required on the discharge of all compressor installations of 1000 horsepower or greater.

Depressuring system piping must be sized to handle large quantities of fluid flow, especially during shutdown scenarios with multiple vessels relieving simultaneously. However, depressuring header size is often the limiting factor in developing a workable system. In large process areas containing several pressure vessels within a single fire zone, or where an entire platform is designed for automatic depressuring to the flare, it may be necessary to stage the blowdown valve sequence or otherwise regulate flow in order to develop feasible designs and control piping sizes.[55]

In a fire scenario, the vapor removal rate required to reduce internal pressure to target levels must account for three sources of generated vapor: 1) vapor evolved from boiling liquid within the vessel, vapor flashing off the liquid as the liquid becomes superheated due to pressure reduction, and increasing vapor volume due to expansion in the vapor space as pressure decreases. This has been described by the following equation:

$$Wt = \sum_{i=1}^{m}(W_{f}t)_i + \sum_{i=1}^{m}(W_{d}t)_i + \sum_{i=1}^{m}(W_{v}t)_i \qquad \text{(eq.9-3)}$$

where W represents the mass flow rate of vapor per unit time
and Wt is the total weight of vapor that must be removed in time t
[source: API RP 521, Second Edition, September, 1982, p.18]

When several vessels operating at different pressures are involved, the design becomes more complicated. The vapor evolved from each vessel must be determined using the specific molecular weights, heats of vaporization, vaporization temperatures and heat transfer conditions to which each vessel is subject.

It is interesting to note that the caveat presented in API RP 521 concerning area limitations in vapor depressuring load determination is sometimes misinterpreted by process engineers performing the calculation. RP 521[56] points out that a fire (in an oil refinery) which can be confined to approximately 2500 square feet (232 m^2) of plot area will not affect the design of the main relief headers if they are also used for vapor depressuring. While this generalization may be valid in so far as "rules-of-thumb" hold true, it should not be interpreted to suggest that the largest area that ever needs to be considered as a single fire zone is 2500 $ft.^2$ although such is frequently the practice.

In addition, as explained in API RP 520, Part I, heat absorption rates from jet fires are not considered; vessel heat absorption is based on the assumption that the vessel is subjected only to pool fire scenarios based on test work dating from the late 1940s.[57]

Recent work by the Steel Construction Institute[58] has shown that whereas the heat flux experienced by vessels directly exposed to open-deck pool fires may range in the order of 100-160 kW/m^2, the incident heat flux levels from open deck jet fires involving gas and two phase releases may exceed 300 kW/m^2, and climb to 400 kW/m^2 in ventilation controlled scenarios.

Production processing modules operating at high pressures require careful analysis in determining vapor depressuring requirements as well as PSV relief loads. Production modules (single fire zones) may easily exceed 2500 ft.^{2} and typically have high densities of equipment and piping that add to relief demands. Pressure release scenarios are likely to be combined with pool fires, and higher heat absorption rates than those traditionally used to determine refinery pressure relief demands can be anticipated.

The new API RP 14J, *Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities* (RP 14J) [presently in draft form and under review] refers the reader to API RP 520 and 521 for the design of gas disposal systems and devices (as well as the ASME Pressure Vessel Code). However, the author of this present work believes that additional research should be carried forward specific to the anticipated heat absorption rates and system demands that can be reasonably anticipated in closed relief systems for offshore facilities, recognizing differences in fire scenarios, heat loads, equipment density, and simultaneous relief demands that are unique to production platforms.[59] Heitner[60] et al. have also suggested areas in which API recommended practices for pressure-relieving system design criteria may be improved.[61,62]

FLAIM does not evaluate the adequacy of the original design basis used to size pressure relief systems nor the method chosen to perform the sizing calculations; FLAIM does ask, however, if this has been done within the recent past and if there is cause for suspecting inadequacies in the existing system.

9.3.4 Flares, Vents and Atmospheric Discharge of Relief Valves

If relief valve discharges are permitted to be discharged directly to atmosphere, air quality and safety may be compromised. In many cases, discharge of a PSV directly to the atmosphere can be accommodated with little fire risk; so operators may consider this the preferred and safer method of discharge as compared to closed relief systems. This is because the associated problems of relief header design, backpressure, mechanical problems, and so forth are eliminated. The simpler approach is generally thought to be the more reliable and safer approach.

However, platforms with congested and closely space equipment arranged in multiple deck layouts may be at greater risk from atmospheric discharge and warrant closed relief systems regardless of air quality considerations. Formation of flammable heavier-than-air vapor clouds and the potential release of flammable liquids and aerosols at deck levels or within modules cannot be tolerated. If production fluids are toxic, e.g., contain H_2S, or could otherwise be harmful to personnel health and safety, closed relief systems must be used.

Disposal of gases and vapors under normal operating conditions e.g., vent gases, and under abnormal conditions, e.g., relief and depressuring gas, is accomplished by routing them to one or more flares, thermal oxidizers, or vent stacks. Vent gases at or near atmospheric pressure should be collected separately by means of a vapor recovery system using a compressor to gather and compress the gas for disposal or recycling. Relief valve and depressuring (blowdown) effluent may be combined[63] and routed to a high pressure/high capacity flare or to an emergency vent stack for safe disposal to atmosphere. A separate system may be needed for low pressure relief. Atmospheric vent stacks are generally sized so as to ensure that the exit velocity of the discharging gases are above 500 ft./sec. in order to achieve good dispersal of flammable vapors in air.

The location of vent stacks and flares require careful planning to minimize fire risks. Often times vents stacks are erected in a vertical position, discharging vapors at high elevations above the main deck. There are four primary concerns addressed by FLAIM: 1) the accumulation of flammable concentrations of vapors at or near personnel, the crew quarters, deck levels and ignition sources, 2) the level of incident radiant heat on platform personnel and decks in the event the vent stack is ignited during discharge, as may be caused by lightning or static discharges, 3) the carryover of hazardous liquids, and flashback.

Maintaining high discharge velocities will reduce the risk of vapor accumulation and flashback. Purge gas may be needed to maintain a positive flow in the system at all times and prevent flashback. Fluidic or molecular seals (seal drums), or similar flame arresting devices are also effective in preventing flashbacks, however, mechanical flame arrestors, e.g., crimped plate types, etc., are generally unreliable due to plugging and high maintenance requirements when used offshore.

Both flares and vent stacks should be designed to account for incident levels of radiation at deck levels. Vent stacks are frequently provided with a fixed extinguishing system to permit rapid extinguishment of ignited vapors.

9.4 *LIQUID SPILL CONTROL PROVISIONS*

Control of burning liquids is vital to the control of fire spread, especially where large quantities of liquid fuel may be rapidly released. As pointed out in API RP 520, Part I, (1976, p. 16) one of the most effective ways to reduce the intensity of heat absorption a vessel is subjected to is by providing drainage away from the vessel so that pools of fuel cannot accumulate below it. Unignited spills must be contained and rapidly drained to platform oily-water treatment facilities before evolved vapors encounter ignition sources.

Not only must liquid removal systems be sized to handle anticipated spills, but provision for firewater discharge must also be accounted for. Burning hydrocarbons can quickly be spread throughout solid deck areas by floating on firewater runoff. Fixed water spray systems and heavy stream discharge devices such as fixed fire water monitors can quickly overload platform deck drains, turning an initially small fire into an uncontrollable series of escalating events.

Platform deck drainage provisions must confine the spread of burning liquids to within designated zones or fire areas, and facilitate removing burning liquid from these areas as quickly as possible without risk of fire spread to adjacent areas. This includes provisions for fire and vapor traps to prevent both fire and gas transmission via the piping systems. On platforms with open deck grating, drip pans or catch basins are used to collect leakage and prevent pollution. Often times drip pans are not well maintained, either due to design flaws or a lack of attention. In the event of a fire, residual undrained hydrocarbons can serve to retain fire directly below process vessels and equipment, not only increasing heat absorption but also exposing critical shut off valves and instrumentation to direct fire exposure.

Because most platform decking is not constructed to slope to drain, liquid flow must be directed using other means. Platforms outfitted with solid deckplate may use a combination of open deck drains, gutters, curbing and channeling to control and direct spills. If drainage capacity is insufficient to keep up with the flow of spilled or leaking hydrocarbons, liquid levels will rise, surrounding equipment and piping within the drainage area with a liquid pool of fuel. Drainage scuppers may provide overflow once the accumulating liquid reaches a certain depth; however, this may nor occur until several inches of liquids have accumulated. Assuming the liquid level mass flow equilibrates at a pool depth of six inches, and using an average regression rate of about 2.5 mm/minute for heavy crude, ignition of the pool would result in a high intensity fire of one hour duration, not considering sequential equipment and piping failures.

Liquids collected from deck drains and drip pans are normally routed to a sump pile or sump tank for gravity separation, from which water and hydrocarbons are extracted for subsequent processing. Crude oils released under pressure may contain significant quantities of dissolved gases, some of which will initially flash-off on release to the atmosphere. Gases crudes and volatile liquids, such as gas condensate (natural gasoline), that drain into the sump pile will create a potentially flammable atmosphere. It is very important that properly designed and maintained gas seals or traps be provided in order to prevent vapors/gases from the sump pile from backflowing into other drain lines and traveling throughout the entire platform via the drain system. This is also the reason the a dedicated closed drain system is normally provided for draining pressurized process equipment and vessels.

Sump piles may be closed-ended or open-ended depending on the design. Closed-ended sumps and sump tanks should be provided with a high level alarms and pumps that automatically start if drain system effluent is building up. Provisions for venting the sump tank or pile to the atmospheric vent header is also important to prevent gas pressure buildup in excess of the hydrostatic heads in system gas traps.

FLAIM wants to know if platform drain systems are suitable for anticipated credible fire conditions with regard to capacity and gas sealing. FLAIM also asks about system maintenance and cleanout provisions, and the general state of knowledge about platform drains.

9.5 *THERMAL ROBUSTNESS AND PASSIVE FIRE PROTECTION SYSTEMS*

Over the last twenty years, many significant advances have been made in offshore technology, yet until very recently, relatively little attention has been directed toward improving the inherent level of platform fire resistance (endurance). This has been largely due to the lack of a rational definition of the offshore platform fire problem in terms of imposed thermal demands and structural system capacity.

Today nearly five years after the Piper Alpha tragedy work continues to clearly define the offshore fire protection problem, and to develop an engineering approach to improving offshore platform fire resistance by extending structural fire endurance.

Anticipated heat flux levels, the rate of heat release, fire growth, and fire duration, i.e. *fire severity*, are key parameters in assessing the predicted rate and extent of progressive failure of structural elements and degradation of system capacity. Much research work is being carried out to characterize the offshore platform fire protection problem in terms of design loads and responses, i.e., the thermal demand (loads) and thermal response.

Fire severity, in terms of the anticipated incident heat flux levels have been shown to vary widely, depending on the LOC event and its location. Structural response to these demands is a function of both fire severity and *thermal* robustness -- the platform's inherent ability to resist thermal impact. Simulating platform behavior under fire conditions by "exercising" structural designs/configurations under thermal demands is now being done to analyze levels of reserve and residual strength requirements needed to achieve fire-based reliability targets.[64]

Such analysis also provides insight into dependencies (or couplings) that may not be significant in conventional load analysis, but are vital to the maintenance of redundancy and robustness during fire exposure. For example, structurally "decoupling" components of the support system serving critically important life-safety functions, such as accommodation module support frames and escape-ways, may prove to be an alternative approach to improve structural fire endurance in a selective and cost-effective manner. Increasing inherent fire endurance through increased thermal inertia[65] may also prove to be a low-cost approach to meeting fire-based reliability targets.

In the case of a major fire incident, a primary objective is to be able to maintain the structure's integrity for a sufficient period of time to permit fire and damage control measures to arrest continued deterioration of capacity and progressive failures, while permitting evacuation of operating and maintenance personnel. This involves the analysis of strategies and alternative approaches, within the context of defined restraints and service requirements.

Figures 9-1 and 9-2 illustrate the offshore fire problem characterized in terms of fire demand (load), system capacity, and exposure duration. The structure must be able to maintain its safety functions for a required performance time, given highly probable fire and explosion damage. This requires appropriately placed redundant elements, provision of ductility (ability to re-distribute loadings), and excess capacity (ability to withstand increased loadings), i.e., fire-based structural design criteria. Ultimately a "baseline-knowledge" of how structural designs factors are influenced by thermally imposed demands will facilitate understanding the need for and application of additional mitigations, such as fire resistive coatings.

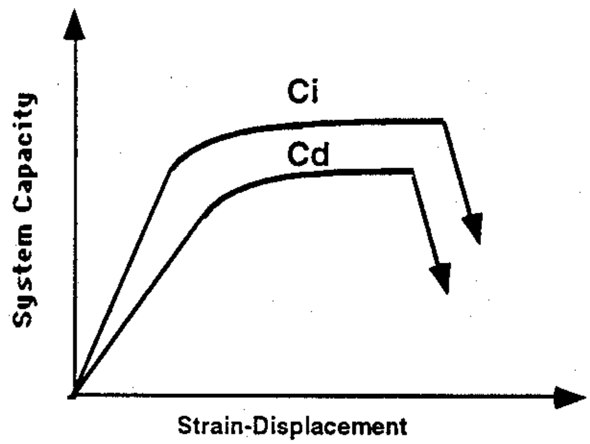

Figure 9-1
Idealized platform fire perfomance
Intact and damaged states

Multiple load-paths, thermally imposed strains involving highly stressed members, and non-linear material response characteristics at elevated temperatures contribute to the complexities of describing system structural response during fire. Reliance on superficial approaches, such as visual inspection, to identify primary and secondary structural steel members (load paths), and then using this as a discriminator to determine fireproofing needs can lead to unexpected failures under fire conditions. Conversely, defining performance targets and system response characteristics under fire conditions allows designers to make informed decisions.

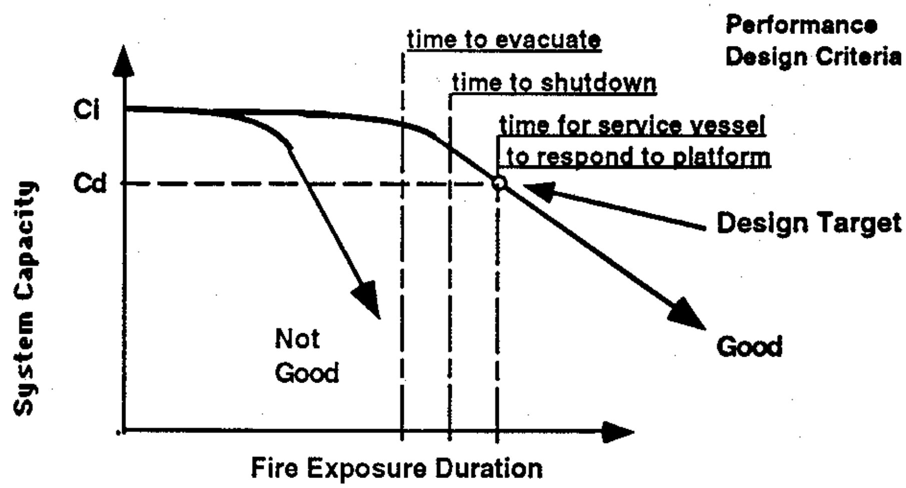

Figure 9-2
Idealized platform fire performance design targets
Required residual strength to achieve fire performance

Performance oriented design criteria, specified in terms of required fire endurance to meet safety goals can be related to residual strength design targets. For example, as illustrated in **Figure 9-2**, the minimum residual strength ($\mathbf{R_{f_{min}}}$) required to achieve the desired level of thermal robustness in order to meet performance criteria, e.g., the curve marked "GOOD," is:

$$R_{f_{min}} = [C_i - C_d]$$

where C_i is the intact system capacity and C_d is the damaged capacity at the performance design target (i.e., in this case to provide sufficient time to allow a fire-fighting service vessel to respond to the scene of the fire and initiate water discharge for exposure cooling prior to structural collapse).

Structural fire risk and the need for passive fire protection on any given platform depends on a very large number of variables. Of greatest concern are fires involving the release of hydrocarbon-based fuels under high pressure and flow rates. Such fires, referred to as high momentum jet fires, cause the highest fire demands offshore. Jet fires, both single phase (all gas) and two phase (a combination gas and liquid) produce the highest heat release rates and heat flux loads, and are the most difficult fires to suppress. In addition, jet fires involving liquids and condensables will often form pools of burning liquid on a platform's deck that may spread fire to other uninvolved areas.

Jet fires may occur at any location on a platform where oil and gas is produced, processed, or transferred under pressure. As already discussed, their occurrence may be directly due to a mechanical or material failure, such as the failure of a flange gasket or pump seal, or due to human error such as cutting into an operating pipeline with a torch. Additionally, jet fires may also be the result of an escalating fire/explosion scenario that began somewhere else on the platform and has caused the failure of a pressure-containing element of the process system.

Multifunctional offshore production platforms are especially vulnerable to an escalating fire scenario due to the necessarily close spacing of high-pressured equipment and the nature of the operations conducted offshore. Any fire that is not quickly detected and suppressed is of great concern; especially on those platforms with accommodation facilities where life-safety is at issue. In general, it can be said that an offshore platform has all of the fire-safety concerns found in a typical onshore commercial or industrial occupancy, plus several additional factors that greatly increase the risk (both likelihood and magnitude) of a significant event. Some of these risk factors influencing the selection of passive fire protection features include:

- unprotected (unfireproofed) structural steel support systems and hydrocarbon-handling equipment that can fail with a few minutes when subject to direct flame impingement.
- layouts and spacing arrangements that do not allow for adequate separation of high risk equipment items or operational areas.
- accommodation facilities located on the same structure as drilling and production operations.
- unprotected egress ways and exiting/escape constraints, especially in environmental hostile areas such as Cook inlet and the Beaufort Sea, Alaska.
- requirements for self-sufficiency in the event of an emergency; reliance on timely outside emergency response is usually not a viable alternative.
- high reliance on system integrity (both mechanical and electrical/control system) to secure safety; extremely vulnerable to consequences of inadequate inspection, maintenance, equipment testing, lack of redundancy, etc.
- minimal time to respond to impending emergencies to avoid escalation; incidents not controlled with the first few minutes can pose a grave danger to welfare of entire platform and crew.
- high susceptibility to explosion damage and incident escalation -- especially

where: equipment areas are enclosed (subject to accumulations of flammable concentrations of gas) and ventilation systems are inadequate or not maintained; no provisions have been made for blast resistance or explosion venting; a high reliance placed on active water spray systems for fire protection (very susceptible to damage from local explosions); no automatic gas detection has been provided; redundant fire pumps are not adequately separated or segregated, etc..

- unprotected data highways for critical control and shutdown systems; open cable trays in grouped configurations employing polymeric coverings that propagate fire and liberate toxic gases when ignited.
- vulnerable control centers that are susceptible to damage from fires and explosions, leading to loss of control and escalation of the scenario.
- multiple operations, many hazardous in nature, being conducted simultaneously on the structure, e.g., simultaneous drilling, production, and work-over operations, multiple construction/inspection/maintenance operations, some of which involve hot work and equipment disassembly, occurring simultaneously during normal operations, use of contract personnel not familiar with platform or inadequately trained, etc.
- especially vulnerable to the consequences of human error; however, tends to place high demands on accuracy of human response; platform networks that require coordination between multiple platforms interconnected by pipeline may be affected by decisions of offsite personnel in emergency situations; communication systems/personnel susceptible to failure/misunderstandings.

Progressive structural collapse can be rapidly induced under severe thermal loadings. Structural system capacity and thermal endurance to withstand the anticipated rates of heat release and maximum heat flux levels of credible worst case fire scenarios is difficult to characterize based on predicted failures of discrete elements within the system. Parallel members most severely stresses (direct flame impingement) must first be characterized; the failure rate of unprotected elements is expected to be very rapid under worst case conditions, such as a high momentum pressurized jet fires that may involve platform risers. Adjacent structural members will experience higher stress levels and a non uniform thermal load distribution will follow that cannot be expected to equilibrate.

Heat balances, using recently determined net average incident heat flux on structural elements, equated with the heated members' thermal inertia may be used to estimate the time required reach critical load bearing temperatures. Critical creep temperature data for load bearing structural steel shapes, including tubulars, is generally well established. In previous work, the heat balance calculation has been carried out for the mid-point of the temperature rise curve, giving a linear approximation to an exponential curve. This has been found to be a reasonable approximation, as the critical temperature would be well below the final temperature of the steel.

Minimum levels of inherent structural fire resistance depends upon the extent to which credit is given to the many factors affecting the imposition of thermal loads. A risk based design criterion should allow evaluation of alternative approaches for achieving performance targets, and for understanding the associated risks of the chosen method. For example, as already discussed, API Recommended Practices RP 520 & 521 does not allow credit to be taken for water spray protection in mitigating heat transfer from fire exposure; however, credit may be taken for thermal insulation that can be expected to remain functional during fire fighting operations.

FLAIM seeks the extent to which passive fire protection measures have been allotted for in the design of the platform. This includes horizontal and vertical separation of fire zones or areas e.g., fire walls and fire rated floor/ceiling assemblies, protection of structural elements with fire resistive coatings, e.g., fireproofing, and protection of important elements essential to personnel safety, e.g., fire barriers for egress routes, fire resistive construction for quarters modules, and so forth. FLAIM also asks questions addressing the inherent thermal robustness and residual strength of the topside support structure (module support frame or MSF). For example, cantilevered decks support CIHH equipment or items affecting personnel safety, such as the crew quarters, escape primary escape routes, etc. are identified and their susceptibility to thermal assault is examined.

9.5.1 Fire Resistive Construction: Firewalls and Fireproofing

The decision to provide fire resistive construction depends on several factors, including the platform operating conditions and throughput, layout and configuration of the topsides, provision of fire-fighting systems and equipment, platform drainage provisions, emergency shutdown capabilities, and the inherent thermal robustness of the structural design. The wellbay may be at significant risk to prolonged fire scenarios.

During drilling operations in it not unusual to experience gas kicks resulting in surface pressures exceeding 6000 to 7000 psig. In accordance with O'Neill,[66] the wellhead area is a significant risk from failures of critical components, such as coke assemblies, diverter valves, and other piping components that are exposed to pieces of shale or rock propelled by gas kicks under very high velocities. Regaining control of a high pressure release may be prolonged because of critical equipment failure and inability to gain access to the well.

Although the risk of blowouts is greatly diminished once the well is completed, workovers routinely occur during the production phase. Downhole operations that involve removal of the surface and subsurface safety valves, setting tubing plugs, and snubbing operations are inherent high-risk operations during which time platform safety is reliant upon the pressure control via the valve seals preventing uncontrolled flow of hydrocarbons under high pressure. As O'Neill[67] points out, the purpose of a workover is to increase flow of the well; this suggests that there are uncertainties concerning the dynamic pressure conditions associated with the operation.

The reasons for installing fire resistive walls or partitions, hereinafter referred to as firewalls, to isolate wellbays and other high risk process areas become more compelling with platform complexity -- as higher concentrations of high pressure hydrocarbon handling equipment and machinery are installed in confined areas with limited space, and limited room for fire fighting. Firewalls also can serve as vapor barriers to separate and segregate equipment components and high risk areas from unignited releases, such as separating wellbays from gas compression facilities, as well as protection from blast effects.

A firewall may be broadly defined as a wall or partition (non-load bearing), erected to prevent the spread of fire from one area or location on a platform to another, and to provide protection from fire exposure. A vapor barrier wall serves to segregate a potential source of hydrocarbon release from a likely ignition source. Such a wall may be used where fire resistance is not a primary concern, e.g., a rated firewall may not be required. Vapor barrier walls used in process areas, typically one-quarter inch thick steel plate bulkhead walls, may afford some limited degree of both fire protection and blast protection, depending on their design details.

Onshore building code construction requirements for firewalls are intended to maximize life safety by inhibiting the early growth rate of a fire. The establishment of building construction requirements rests on the premise that life safety is greatly influenced by early flame spread -- which in turn depends mainly on types of materials used for construction, interior furnishings and finishings, e.g., the combustible loading of a building. Consequently, standard fire tests for building construction assemblies have been developed and adopted which reflect anticipated fire conditions in buildings due to typical fire loadings, i.e., the amount of interior combustible materials. Although such a procedure may be suitable to assure a minimum level of fire protection is achieved for conventional building structures, it would be less than meaningful to apply the same analysis to an offshore production platform without accounting for the extreme differences in anticipated fire conditions or safety goals.

As in any conventional occupancy, fire compartmentalization on an offshore production platform is highly desirable; but construction objectives and restraints extend beyond those normally encountered elsewhere. Specifically the objectives of platform compartmentalization may be summarized as follows:

- to minimize the potential size of area involvement in a fire/explosion scenario, thereby reducing initial fire size and intensity, limiting fire spread, minimizing personnel injury, equipment damage and production loss, and minimizing fuel contribution from damaged equipment

- to maximize fire extinguishing system effectiveness while reducing the cost of system components

- to facility onboard fire fighting efforts and allow safe shutdown and depressuring of process equipment

- to improve life safety by reducing the travel distance to a place of refuge and/or escape

- to limit the damage of an explosion by venting the destructive force utilizing a combination of explosion relief (vented walls) and pressure resistant walls -- most fire walls and vapor barrier walls should also serve as blast resistant walls.

Sectional walls (e.g., separating fire zones) must be strong, elastic, light weight and require a minimum of space, such as those constructed of steel plate. Steel construction offers high strength, ease of fabrication and modification, and infers uniformity of quality.

The use of unprotected steel plate to fabricate a "firewall" has been an accepted and common practice on OCS production platforms. The term "firewall" is used here in the context of API RP 2G[68] in which a firewall is defined as: *a partition fabricated from noncombustible materials to prevent the spreading of flames and to provide a heat shield.* A specified degree of fire resistance is not implied.

From a blast resistance standpoint, monolithic walls which have the greatest degree of elasticity are desirable. Steel-plate walls are highly ductile, can take large deflections, and absorb a high quantum of blast energy. Typical onshore construction using masonry or concrete block is not only impractical for OCS platforms, but also offer little lateral resistance and would tend to fragment into projectiles when subject to explosive forces. Reinforced concrete or concrete insulated steel walls provide sufficient strength and much greater fire resistance, but are considered too heavy and large for use on steel jacket platforms. Some composite wall assembly designs are now coming into use for selected applications, such as for protecting the crew quarters.

Unprotected (bare) steel bulkhead walls are vulnerable to thermal impact; they cannot provide any degree of extended fire resistance without an added degree of exposure protection, e.g., protective coatings or water spray protection. In addition, steel bulkhead walls are often penetrated by piping runs, cable trays, hatches, and doorways. Without proper engineering, such penetrations provide a pathway for both vapor migration and heat and smoke transmission.[69]

Hydrocarbon fueled fires are of course much different from typical commercial building fires upon which standard fire tests such as NFPA Standard 251[70] (ASTM E-119) are based.[71] Liquid fueled pool fires are much more rapidly developing than conventional cellulosic fueled fires, reaching peak heat flux levels and rates of heat release in a matter of a few minutes. The resultant thermal shock and thermal intensity imposed upon structural elements is corresponding much more severe. This difference has long been recognized in the petroleum industry and has led to the development of proprietary testing procedures, often referred to as "high-rise" fire tests, due to the steep rise of the time-temperature curve. Mobil Oil, Exxon, the Norwegian Petroleum Directorate (NPD), and the U.K. DOE were the first to develop alternative testing requirements for rating fire resistive construction on offshore platforms.[72]

Following the lead of these organizations, Underwriters Laboratories (UL) developed a high-rise fire test[73] designed to reflect the conditions of petroleum facility fires, UL 1709, *Structural Steel Protected for Resistance to Rapid Temperature Rise Fires*, and ASTM is followed suit. The United Nation's International Maritime Organization (IMO) has also revised their standard shipboard fire test procedures to include hydrocarbon fire test ratings (H-rating).[74]

In the ASTM E-119 test procedure (UL 263, NFPA 251, ISO 834), the standard cellulosic fire time temperature curve rises to 1000°F after 5 minutes, whereas in UL 1709 (SOLAS High-Rise Fire Curve, et al.) the temperature rises to twice this in the same amount of time. The heat flux levels are also much more severe. The high-rise fire test heat flux level is approximately 55,000 BTU/ft^2 hr. as compared to 16,300 BTU/ft^2 hr. for the standard test. For this reason, a four hour rated ASTM E-119 material is only equivalent to a 2 to 3 hour rated UL 1709 material.

Hence, an interesting juxtaposition is encountered: recognition and development of more appropriate fire testing standards to account for the severe thermal demands encountered in petroleum handling facilities has been pursued vigorously; however, many existing GOM offshore platforms have followed a tradition of using non-fire rated (unprotected) structural steel members and plate bulkhead walls, placing reliance largely on preventative measures, and fixed water spray systems or the crew's ability to quickly cool exposures and control fire spread before structural collapse can progress.

Fireproofing guidelines for protecting structural steel supports and critical process components are presented in API Publication 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants.*[75] It is interesting to note that the first draft of this document was developed in 1982, but that it took six years to finalized due to the widely divergent opinions that exist among oil company members regarding a consensus on what should be fireproofed and how to accomplish the task. Consequently, it is not surprising to find widely differing practices offshore, depending on company policies and management's perception of the value of this risk reduction measure.

FLAIM seeks to assess the balance between active and passive fire protection measures, recognizing that many factors affect the decision making process. The main objective is to identify circumstances in which reliance is being placed on an inappropriate risk reduction measure for the prevailing conditions.

9.6 *DESIGN FOR EXPLOSION PROTECTION*

Most production platforms have not been designed with features engineered to mitigate explosions. Since Piper Alpha, more attention is being given to blast effects research and methods of blast-hardening. FLAIM examines three aspects of platform explosion protection features: vapor control provisions (explosion prevention), explosion venting provisions (blast wave mitigation), and blast resistance and hardening features of platform design.

9.6.1 Vapor Control Provisions

Three conditions are required[76] for an open-air vapor cloud explosion and fire: 1) flammable gases or vapors must be present, 2) the gases or vapors must be mixed with air (oxygen) within specified limits, e.g., be within the flammable or explosive range consisting of an upper and lower limit, and 3) an ignition source of sufficient energy to ignite the flammable mixture is required. Area classification practices, such as RP 500B for offshore platforms (and 500A for refineries,[77] etc.) are based on principles of fires and explosions prevention that seek to prevent all three of the above conditions from occurring simultaneously at any given location, either during normal operating conditions or during abnormal operating conditions. This essentially involves ensuring that ignition sources and flammable concentrations of vapors and gases are not present in the same area at the same time.

In order to accomplish this objective, classification criteria has been developed to judge the likelihood of all three of the listed conditions occurring at the same time, either during the normal course of operations or during scenarios involving process upsets, leaks, etc., e.g., abnormal conditions.[78] A primary discriminating factor used in applying the criteria, and a vitally import aspect of platform safety as demonstrated by the difference in loss rates between GOM and North Sea platforms,[79] is the adequacy of ventilation. Inadequately ventilated areas are much more subject to the accumulation of gases and vapors which, in turn, may cause a fire or explosion if ignited. Ventilation, either natural or mechanical, prevents vapors from collecting and thereby decreased the risk of explosion and fire.

Adequate ventilation has been defined by RP 500B[80] based on NFPA's definition in the National Fire Codes[81] as follows:

> *Adequate ventilation: natural or artificial ventilation that is sufficient to prevent the accumulation of significant quantities of vapor-air mixtures in concentrations above 25% of their lower flammable (explosive) limit (L.E.L..).*

This definition has been included in OCS Orders[82] for Oil and Gas Operations. As a practical guide, OCS Orders illustrate what constitutes adequate by referring to ventilation rates of 1 cfm/ft.^{2} of solid floor area for enclosed areas or one change of room air volume each 5 minutes, e.g. 12 air changes/hour.[83] Neither of these illustrations, however, are meaningful when the factors that affect achieving the performance criteria defined above are understood. Code specified design criteria based on air changes/hr. or cfm/ft^2 are inconsistent with actual ventilation requirements.[84]

Enclosed oil and gas handling facilities on production platforms require sufficient rates of ventilation to remove and prevent the accumulation of fugitive emissions that are continually occurring during normal operations. If such emissions did not occur, then vapor accumulation would not be a concern[85] except in the case of an LOC event, e.g., an abnormal condition under which large quantities of vapor and gas may be suddenly released -- a condition that is considered impractical to design ventilation systems to handle.[86]

Therefore, to meet performance criteria for ventilation adequacy, there are two parameters that must be quantified: the rate of vapor release into the enclosure and the corresponding rate of ventilation required to prevent vapor concentration from exceeding 25% of the L.E.L.. Assuming instantaneous mixing, the differential increase in the vapor concentration within an enclosure in time $d(t)$ is equal to the rate of addition minus the rate of removal in the exhausted air. If the rate of addition of vapors is greater than the rate of removal, the vapor concentration will increase. This balance can be represented by the equation:

$$VdC = Gdt - \frac{QC}{dt} \quad \textit{where:} \qquad \text{(eq.9-4)}$$

V is the volume of the enclosure or room

C is concentration of added vapors

Q is the ventilation flow rate

G is the rate of vapor addition (fugitive emissions)

and therefore:

VdC is the net change in room volume vapor concentration

Gdt is the amount of vapor added in time dt

$\frac{QC}{dt}$ is the amount of vapor removed in time dt

Integration of the equation yields:

$$\int_{Co}^{Ci} \frac{dC}{G - QC} = \frac{1}{V}\int_0^t dt$$ and if the initial concentration $C_0 = 0$, this yields

$$C = \frac{G}{Q}\left(1 - e^{\frac{-Qt}{V}}\right) \qquad \text{(eq.9-5)}$$

where $\frac{Qt}{V} = N$ = number of room air changes;

and, if K is an efficiency factor, then

$$C = \frac{G}{Q}\left(1 - e^{KN}\right) \qquad \text{(eq.9-6)}$$

Equation 9-6, above, is the same equation found in Appendix D of NFPA 69, *Explosion Prevention Systems,*[87] where values for the efficiency factor *"K"* are given ranging between 0.2 and 0.9. The vapor concentration *"C,"* is given in parts per million (ppm); "G," the rate of vapor release is in cubic feet per minute (cfm), and the ventilation rate, e.g., fresh air makeup, is also in cfm; *"N"* is the theoretical number of air changes in the room.

What is interesting about this equation is that as (KN) $\rightarrow$ 3, the expression $\left(1 - e^{KN}\right)$ approaches unity and therefore C is solely dependent on the rate of vapor release divided by the rate of ventilation, i.e., floor area, room volume, or number of air changes per hour are not determining factors in assessing required rates of ventilation.

While perhaps this may be intuitively obvious, a method for quantifying ventilation rates based on the rate of vapor release was not generally recognized prior to 1986.[88] In 1987, the API Committee on Standardization of Production Equipment elected to adopt the methodology proposed by Gale and include it in the 1987 revision of RP 500B, Appendix B. Because of concern over the newness of the approach, [89] API defined a new category of ventilation referred to as "Limited Ventilation," and reduced the previous called for rate of 12 air changes per hour to six air changes per hour for evidence of mechanically supplied ventilation adequacy.

For naturally ventilated buildings and enclosures, API elected to apply a safety factor of 2 for sizing louvers and vent openings based on thermally induced convective air movement, e.g., designers should use 12 air changes per hour as a basis for calculation.[90]

FLAIM asks several question regarding ventilation of enclosed oil and gas handling areas, seeking to determine if the platform has adequate rates of ventilation, either mechanical or natural, and if appropriate safeguards have been taken in areas subject to gas accumulation.

9.6.2 Explosion Venting

Explosion venting practices and design criteria are presented in NPFA 68, *Guide to Venting of Deflagrations*.[91] Explosion venting is an inexact science due to the large uncertainties in modeling both explosion overpressures and structural response. The rate of pressure rise is of primary concern, as determined by the combustion characteristics of the fuel, the conditions of its ignition, degree of confinement and the geometry of the surroundings from which the blast wave is propagated. The extent of induced turbulence due to equipment congestion and obstacles to has shown to be especially important.[92] Some materials, such as hydrogen, have such high rates of pressure rise that explosion venting cannot be effectively implemented.

The primary objective of explosion venting is to relieve blast pressures created due to confinement of the combustion reaction. Unconfined vapor cloud explosions (UVCEs) may also occur should sufficient quantities of highly flammable materials be released and ignited. UVCEs can be devastating, and cannot be mitigated by explosion venting.[93] As discussed in API RP 750,[94] Davenport's survey[95] indicates that most

UVCEs involved the sudden release of at least five tons or more of flammable vapor, as may possibly occur in a petroleum refinery during a catastrophic scenario. FLAIM has not addressed the occurrence of offshore UVCEs, considering their likelihood to be negligible.

When released vapor is ignited and begins to combust, the heated products of combustion occupy a much greater volume than the unburnt fuel, thereby expanding and "pushing forward" the flame front and heated gases into the unreacted vapor. Pressure waves compress the unburnt fuel ahead of the flame front and increase its temperature. The now preheated fuel, in turn, burns faster, producing combustion products at a correspondingly higher rate.[96] The ratio of expansion is highest (factor of about 8) when the fuel is at its stoichiometric mixture. If the free expansion is restricted walls or otherwise confined, destructive overpressures are developed.

The speed of the combustion reaction is influenced by turbulence. Any objects within an enclosure that interfere with or otherwise block the expanding gases induces additional turbulence and hastens the speed of the reaction. If the configuration of the area in which the explosion is propagating from is such that a high level of turbulence is induced, say due to the extent of congestion within a production module, the reaction rate may be so accelerated so as to reach destructive levels before venting provisions can open to relieve and limit the overpressures.

There are two fundamental considerations that go into the design of explosion relief panels: 1) the area and arrangement of the explosion vents and, 2) the inertia and the fastening system used to retain the panels in place.

Blowout panels must be of sufficient surface area to vent the combustion productions without allowing pressure buildup. Further they should be arranged uniformly throughout the protected area, not located just along one wall. This of course is a problem for interior modules that have only two end wall sections that face the sea. However, even modules located on the platform perimeter may encounter a problem in providing adequate space for explosion relief due to external obstruction on the exterior of module walls, such as turbine exhaust lines, risers, or personnel catwalks.

If blowout-panels (vents) have too much inherent inertia, the initial force of the developing explosion may not be able to start to move the panels soon enough nor fast enough to prevent destructive levels of overpressure from being reached within the area. Research[97] at the Norwegian Institute of Technology (SINTEF) using numerical simulation modeling has let to the development of an offshore platform explosion relief system using blowout panels that are reportedly capable of fully opening with thirty milliseconds.

Another problem facing the designer is to provide a suitable means to retain the panels in place under high wind loads, and yet allow them to function as intended. Strong winds blowing across the platform can create areas of low pressure on the downwind side of the structure that may suck-out explosion vents. Providing hinges and other mechanical retention devices prevent loss of the panels, however, resorting to stronger fastening systems can void their effectiveness.

Provision of explosion relief is primarily an issue for enclosed modules on platforms located in hostile environments such as in Alaska or the North Sea. However, newer, deepwater GOM platforms may warrant extensive analysis for application of this risk reduction measure. FLAIM asks if a platform has enclosed oil and gas handling facilities, and if the facility has been designed with explosion relief provisions.

9.6.3 Blast Resistant Construction and Blast Hardening

Blast resistant designs have been used for many years in the petroleum industry, although generally only with regard to the construction of central operating centers (control rooms) located close to one of more refinery processing units. Typical design criteria[98] for blast resistant construction are 3 psi static overpressure load and 1 psi negative suction pressure load applied to all exterior surfaces. It has only been in the post-Piper Alpha period that the significant research efforts have been devoted towards better defining blast loads and structural responses that can be anticipated on offshore platforms.

An idealized explosion pressure profile is illustrated in below in **Figure 9-3**

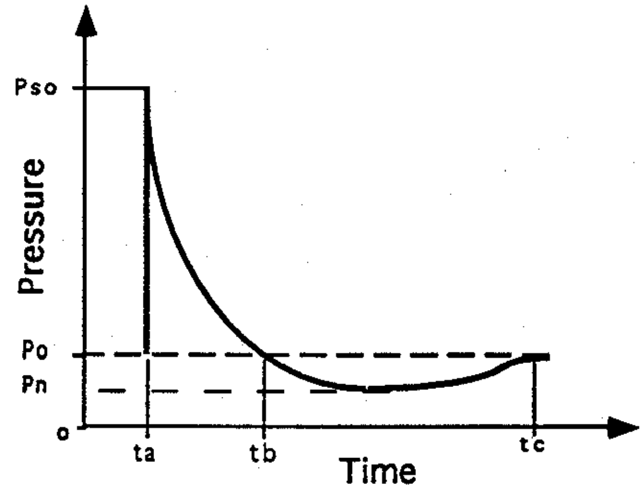

Figure 9-3
Idealized Blast Wave Pressure Profile

Source: Strehlow, R., et al., ***The Characterization and Evaluation of Accidental Explosions,*** **NASA Report CR 134779, AAE 75-3, UILU-ENG 75 0503, Aerospace Safety Research and Data Institute, Lewis Research Center, National Aeronautics and Space Administration, Cleveland, OH**

As shown, as an explosion begins, their is a rapid rise in pressure (wave front) above the ambient pressure, P_o, to a peak incident pressure, P_{so} at t_a, also referred to as the so-called peak side-on pressure, e.g., the peak pressure measured "from the side" as the shock wave was passing by an observer. The pressure then declines and drops below the ambient pressure to create a partial vacuum or negative phase (rarefaction) between t_b and tc, which lasts longer than the positive pressure phase. It is the positive pressure phase between t_o and t_b that is of most concern[99] from a blast effects standpoint. The positive area under the pressure decay curve is known as the positive impulse -- a measure of the impulse wave, which accounts for the duration of the shock wave and is important in evaluating structural response.

The effective peak blast overpressure is usually much higher than represented by the ideal side-on pressure due to dynamic effects of wave reflection. Immediately behind the shock wave is a region of heated high velocity gas that generates a dynamic pressure that is proportional to the velocity and density of the moving fluid. The peak dynamic pressure may be larger than the peak incident pressure in large explosions, e.g., where P_{so} > 70 psi.[100] The peak dynamic pressure is of great importance in modeling structural effects. For example, during in 1992 Hurricane Andrew devastated production platforms in the GOM with winds exceeding 160 mph. This velocity would be achieved with a peak dynamic pressure of 0.7 psig and a peak overpressure 5.0 psig.

If an infinite wall were to be placed perpendicularly (normally) to the path of the shock wave so as to stop all flow behind the propagating wave, an upper limit of the (reflected) peak overpressure would be obtained, P_{rmax}. Near the origin of the explosion, values of P_r/P_{so} may be quite high, depending on the angle of wave incidence & reflection when an obstruction is encountered. This ratio falls to between 2 to 2.5 as the blast wave travels further away from the ignition source and the incident pressure drops to under 10 psi.[101]

According to Tunkel[102] if a blast waves strikes a flat shape, such as a bulkhead wall, the value of peak incident pressure at the surface may be used to estimate damage effects. For example, control room and crew quarters windows can be expected to shatter at values of P_{so} between 0.5 to 1.0 psi, and corrugated steel or aluminum paneling would be expected to buckle and fail at points of connection between 1.0 and 2.0 psi.[103] At a level of 5 psi eardrum rupture is likely, followed by lung damage above 15 psi and death above 35 psi, depending on the duration of the pressure pulse. However, for structural design, a much more detailed approach is required.

The loading imparted to an object by an explosion results from three types of pressure and two types of loads: the incident pressure, dynamic pressure, and the reflected pressure; and diffraction loading and drag loading, both of which are time dependent. Enclosed modules, rooms, etc. have been generally thought to be most affected by diffraction loading,[104] whereas structural elements (braces, chords, etc.) and piping are impacted more by drag forces.[105]

Diffraction loading is the maximum force exerted on an object during the time in which it takes the shock wave to travel past and diffract around it. The longer the shock wave takes move past an object, e.g., the more a wave has to diffract, the larger is the resultant force.

Drag loading results from the dynamic pressure effects, and depends on the drag coefficient of the object, much the same manner in which wave and current forces are accounted for in design of a jacket. In the case of an explosion, however, the dynamics are much more complex.

Simple models[106] using static versus impulsive loading analogies based on the natural frequency of the element have been used in the past to approximate response. However, the large degrees of uncertainty associated with combustion dynamics, and specifically the effect of induced turbulence, has limited the usefulness of such approaches.

Beginning in 1982, a consortium of six major North Sea operators (Statoil, Hydro, British Petroleum, Esso, Elf and Mobil Oil) funded a research program (the Gas Explosion Research Program --GEP) that has lead to what is generally considered to be the most advanced three dimensional numerical model for simulating the development and effects of offshore hydrocarbon gas explosions. Seeking to better understand the parameters affecting gas explosions on offshore platforms, the Gas Explosion Research Centre at the Christian Michelsen Institute (CMI) in Bergen, Norway, launched an intensive investigation[107] to address several issues, including induced turbulence, geometry, and damage effects.

This led to the development of the Flame Acceleration Simulator Code[108] (FLACS) by Dr. Bjorn Hjertager. Based in part on the Navier-Stokes equations, the code was validated using, *inter alia*, a 1:5 scale mockup of an offshore compressor module, fully equipped and instrumented for detailed analysis explosion parameters.

FLACS has received widespread attention in recognition of its advancement of explosion analysis,[109] and has employed on several offshore projects for blast analysis. FLACS was used in Petrie's[110] interim investigation of the Piper Alpha accident, in which a listing of FLACS various applications was included.

FLAIM asks if provisions for blast resistance have been incorporated into the structural design of high risk platform areas. In addition, FLAIM seeks to identify situations where differences in blast wave response may make some equipment and systems particularly vulnerable to failure, e.g., at bulkhead pipe penetrations and firewalls constructed of unstiffened plate and protected by non-ductile thermal insulation systems.

9.7 *INSPECTION AND TESTING OF RISK REDUCTION MEASURES*

FLAIM recognizes and accounts for the importance of routinely inspecting and testing platform safety systems and equipment. Without regular inspection and testing of platform risk reduction components, reliability of safety systems and equipment cannot be assured. This can be simply illustrated by comparing the expected unavailability of a component or equipment item that is never tested with one having the same expected failure rate but is routinely tested. The expected unavailability, ε, for a piece of equipment that is never tested can be estimated from the following equation:

$$\varepsilon = 1 - e^{-\lambda\tau} \qquad \text{(eq. 9-7)}$$

where λ is the failure rate and τ is the service time in hours.
Using a failure rate of 1×10^{-5}/hour and a service time of 10,000 hours, Levine[111] calculates an expected unavailability factor of over 63%.

For a routinely inspected and tested component, the expected unavailability can be estimated using equation 9-8.

$$\varepsilon = \frac{1}{2}\lambda \mathrm{T} \qquad \text{(eq. 9-8)}$$

where T is the test interval in hours. If, for example, the component is inspected and functionally tested after each operating period of 1000 hours, then the unavailability is reduced from a factor of more than 63% to 0.5%.

Many factors affect failure rates, including service/environmental conditions, operating demands/cycles, age, etc. Establishing the testing frequency should consider both the criticality of the component's availability and the expected failure frequency for the service conditions. Failure rate data for offshore platforms has been collected for a number of years for various process and safety system components, as well as other items, and is available in OREDA.[112] Using this information and their own experience-based data, operators may derive minimum recommended run-times between inspections for all critically important process and safety system components onboard their platforms.

Over the past four years, a pilot program has been underway to develop risk-based inspection guidelines for offshore platforms as well as for other industrial operations such as chemical and power plants. Following from the development of probabilistic structural mechanics for structural reliability analysis and design, the American Institute of Mechanical Engineers has formed a Risk-Based Inspection Guidelines Research Task Force[113] to foster development of a methodology for assessing inspection and testing needs throughout industry. The work of this task force is expected to be of significant importance to offshore operators who find themselves extremely hard pressed to quantify inspection and maintenance demands and justify program costs in a meaningful way.

FLAIM asks if critically important system components and routinely inspected and tested. FLAIM seeks to identify those key equipment items that may not have been designed and installed to facilitate full functional testing during normal operation. For example, a pressure vessel may not have been provided with redundant safety valves, necessitating taking the vessel out of service in order to remove and test the valve. Similar scenarios involving shutdown devices and controls without bypasses or other provisions to permit full functional checks can lead to inadequate testing, with the testing interval (T) being driven by overall platform turnaround schedule and production demands rather than the particular component's failure rate and testing needs. This is of particular concern in the case of those components that may only be called upon to operate in time of an emergency, and whose failure does not directly impact platform production and may go undetected.

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[13] Refer to Lim, L.H., (Occidental of Scotland), *Use of copper-nickel alloy materials for offshore sea water piping*, Society of Petroleum Engineers of the American Institute of Mining, Metallurgical and Petroleum Engineers, Paper No. OE-77.II. SPE 3.6680.3, presented in Aberdeen scotland, Steptember 14-15, 1977; also see Bedford, B.P., *Offshore Water Services*, The Chemical Engineer (U.K.) June, 1977, pp.397-402

[14] Thomas, P.H., *The Size of Flames from Natural Fires*, Ninth International Combustion Symposium, Combustion Institute, Pittsburgh, PA, 1963, pp. 844-859

[15] Cockbain & Jermstad, *Design of the Draugen Topsides for the Effects of Gas Explosions*, OTC 6477, Offshore Technology conference, Houston, TX, May, 1990, pp. 489-496

[16] Xu and Kirkvik, *Design Against Explosion Loads in Offshore Structures*, Proceedings of the First International Offshore and Polar Engineering Conference (ISOPE), Edinburgh, August, 1991, Volume IV, pp. 183-187

[17] The Steel Construction Institute (U.K.), *Interim Guidance Notes for the Design and Protection of Topside Structures Against Explosion and Fire*, , SCI-P-112, Document No. 243, January, 1992, pp. 3.1 - 3.38

[18] Bleakley, W., *Protect platform workers with fire-fighting know-how*, The Oil and Gas Journal, September 13, 1971, pp. 97-101

[19] The Steel Construction Institute (U.K.), *Interim Guidance Notes for the Design and Protection of Topside Structures Against Explosion and Fire*, SCI-P-112, Document No. 243, January, 1992, p. 3.14

[20] Achenbach, G., et al., *Water Spray Wellhead Fire Protection Systems for Offshore Structures*, OTC 2234, Offshore Technology Conference, Houston TX, May, 1975

[21] Gore, J. & Evans, D., *Development of Hazard Assessment and Suppression Technology for Oil & Gas Well Blowout and Diverter Fires*, OCS Study MMS 91-0057, Technology Assessment and Research Program for Offshore Minerals Operations, 1991 Report, Minerals Management Service, pp. 27-32

[22] Pfenning, D. et al., Suppression of Gas Well blowout Fires Using Water Sprays: Large and Small Scale Studies, Presented at the American Petroleum Institute, Committee on Safety and Fire Protection, Fall Meeting, San Antonio, TX, September 11-13, 1984; also see Water *Sprays Suppress Gas Well Blowout Fires*, Oil and Gas Journal, Volume 83, No. 80, 1985. pp. 17-23

[23] POP SPRAY brochure, OPSRAY (U.K.) Ltd., 26 Dover St., London, W1X 3PA, April, 1985

[24] Munson, R.E., *Safety Considerations for Layout and Design of Processes Housed Indoors*, Loss Prevention, A CEP technical manual, American Institute of Chemical Engineers (AIChE), Volume 13, 1980, pp. 15-19; E.I. Du Pont de Nemours and Co. ; paper presented in Houston at the 86th annual meeting of the AIChE in conjunction with the 10th Petro-chemical and Refining Exposition (PETRO-CHEM), April 2-5, 1979.

[25] SAFEDECK brochure, Oil Industry Services A/S, P.O 46, 4620 Vågsbydg, Kristiansand, Norway

[26] National Fire Protection Association, NFPA 13-1991, *Installation of Sprinkler Systems*, and NFPA 13A-

1987, *Inspection, Testing and Maintenance of Sprinkler Systems,*

27 National Fire Protection Association, NFPA Fire Protection Handbook, Fourteenth Edition, 1976. p. 13-21 & p. 15-32

28 National Fire Protection Association, NFPA No. 12A, Standard for Halogenated Extinguishing Agent Systems -- Halon 1301, also NFPA No. 12B, Standard for Halogenated Extinguishing Agent Systems -- Halon 1211

29 The author of this present work was the responsible fire protection engineer in charge of system design, precommissioning, and startup of Halon fire protection systems provided for British Petroleum by Brown & Root, Inc., and subsequently by Bechtel Petroleum, Inc. spanning a period of more than ten years and as many sealifts. These facilities reportedly had both the largest Halon systems ever designed and the largest total amount of onsite storage of any petroleum facilities of that period.

30 Echternacht, J., *Gaseous Fire Protection Extinguishing Agents for Offshore Platforms*, SFPE Report 81-5, Society of Fire Protection Engineers Technology, Boston MA, 1981

31 In early 1992 President Bush signed an agreement calling for a U.S. production ban on Halon and CFC-producing chemicals by December 31, 1995. Subsequent to this, a meeting of the Montreal Protocol's international signatories on November 25, 1992 called for an earlier deadline of January 1, 1994 -- a date likely to become U.S. Law as well. Further, in the fall of 1992, duPont, who is the largest Halon (cont'd)... manufacturer, announced phaseout of worldwide sales by December 31, 1993 [See Harrington, J.L., *The Halon Phaseout Speeds Up*, NFPA Journal, March/April, 1993, pp. 38-42

32 Taylor/Wagner Inc., United States Halon Bank Management, a DRAFT Discussion Paper, October 27, 1992, Halon Alternatives Research Corporation (HARC), Washington D.C. in personal correspondence with W.E. Gale, Jr., dated November 24, 1992

33 During the mid-1980's the author of this present work served for several years as a member of the NFPA Standard 17 Committee on Dry Chemical Systems as a representative of the American Petroleum Institute. During this time, the Committee was responsible for developing and issuing a new NFPA Standard, No. 17A, Wet Chemical Systems.

34 U.S. Code of Federal Regulations, 30CFR.123 (8) (iii), *Fire fighting Systems*, July, 1992, p. 235

35 The Maui A platform was designed to produce gas and gas condensate for Shell, B.P. and Todd. The author was lead resident fire protection engineer in New Plymouth, New Zealand during the early 1970's.

36 American Petroleum Institute, Recommended Practice 14C (RP 14C), *Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms*, Fourth Edition, September, 1, 1986, Emergency Support Systems (ESS), pp. 81-84

37 National Fire Protection Association, NFPA Standard No. 72, Installation , Maintenance and Use of Protective Signaling Systems, and NFPA Standard No. 72E, Automatic Fire Detectors,1990

38 The first recognized meaningful method of quantifying what constituted adequate ventialtion was described by the author of this present work in an article published in the Oil and Gas Journal in the mid-1980s. The described method was subsequently adopted by API in their recommended practice, RP-500. This led to adoption of the methodology by the Institute of Petroleum (U.K.) and by Canadian authorities, and remains as the current accepted approach for quantifying ventilation rates based on fugitive emissions. See API RP 500B, Recommended Practice for Classification of Locations for Electrical Installations at Drilling rigs and production facilities on Land and on Marine Fixed and Mobile Platforms, Oct. 1, 1987

39 The author of this present work was involved in development of the first commercially available gas controllers designed with RFI shielding. These units, developed by General Monitors Corporation and Rexnord Inc.(formerly Dictaphone Gas Detection), were the result of new performance specifications developed for British Petroleum's North Slope gathering centers in the mid-1970's in response to severe EMI/RFI problems experienced with then state-of-the-art units. Largely as a result of this work all combustible gas detector manufacturers began offering RFI protected systems and standards organizations, such as the API and ISA incorporated RFI performance guidelines in their publications.

40 American Petroleum Institute, API RP 14F, *Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms* (RP 14F), Third Edition, September, 1991, pp. 54-55; also see ISA Standard 12.13, Part I, *Performance Requirements, Combustible Gas Detectors*, and Part II, *Installation Operation and Maintenance of Combustible Gas Detection Instruments*, Instrument Society of America

41 U.S. Code of Federal Regulations, 33CFR146 Subpart B, Manned OCS Facilities, p.135, § 146.105

42 Smith, R., *Design reliability into offshore shutdown systems*, Oil and Gas Journal, October 10, 1977, pp. 121-127

43 see API RP 14C, *Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms*, American Petroleum Institute, Fourth Edition, September 1, 1986, p.81

44 Arnold, E. & Sikes, C., *Generic HAZOP would improve Gulf of Mexico process safety*, World Oil, November, 1991, p.61

45 Pressure Relief Valves is a generic term applied to relief valves, safety valves or safety relief valves. A relief valve is an automatic pressure-relieving device actuated by the static pressure upstream of the valve, which opens in proportion to the increase in pressure over the opening pressure. A relief valve is used primarily to protect pressure vessels handling liquids. Pressure safety valves (safety valves) are normally used in gas and vapor service or in steam and air service. They are sometimes called "Pop Valves" because unlike relief valves, a safety valve fully opens at set pressure, e.g, pops-open, and remains open until internal vessel pressure is lower than its set pressure.

46 see API RP 521, *Guide for Pressure-Relieving and Depressuring Systems* (RP 521), American Petroleum Institute, Second Edition, September, 1982, p. 7

47 API RP 520, Recommended Practice for the Design and Installation of Pressure-Relieving Systems in Refineries, Part I -- Design, Fourth Edition, 1976, p.11, equation (9)

48 Credit for thermal insulation is contingent of the material's ability to resist dislodgement by fire hose streams during fire-fighting efforts, however, no consideration is presently made for blast resistance or resistance to high pressure streams from jet fires. In April of 1989 a small high pressure line failed in a major Bay-Area refinery causing a high pressure jet to impinge on thermally insulated structural supports for a 100 foot high reactor. The force of the impinging jet fire caused failure of the insulation within a few minutes and collapse of the reactor, seriously injuring several operators. Also note that F=1 for protection provided by fixed water spray and deluge systems, e.g, no credit is allowed, due to system reliability considerations. Refer to API RP 520, Part I, Fourth Edition, 1976, page 16.

49 The latent heat of vaporization becomes zero at the critical temperatue and pressure

50 Gale, Jr. W., A new level of safety for LPG storage, Applied fire safety engineering research aspects, C.E. 299 Research Report, Department of Civil Engineering, University of California, May 21, 1988

51 A relief valve's discharge capacity directly depends on the built-up backpressure in the discharge (relief) header which develops as a result of flow after the valve opens. Many PSVs that formerly discharged directly to atmoshpere are now connected to closed relief systems that go to the platform flare. If excessive backpressure is experienced in the relief header due to undersizing or failure to realistically account for all vessesl within a single fire zone, e.g, vessels subject to simultaneous fire exposure, then allowable vessel accumulation pressures may be exceeded. Note that OCS Orders take exception to ASME Boiler and Pressure Vessel Code by limiting the maximum set pressure of nonredundant relief valves to the maximum allowable working pressure of the vessel, e.g., no allowance for accumulation pressure is permitted. Refer to 30CFR250.123, *Additional Production System Requirements,* Code of Federal Regulations.

52 U.S. Code of Federal Regulations 30CFR250.123

53 This criterion is based on vessel wall temperature versus rupture stress and applies generally to vessels with wall thicknesses of approximately 25 millimeters or more. Vessels with thinner walls generally require a greater depressuring rate. The depressuring rate required to prevent stress rupture is also a function of metallurgy of the vessel, the initial wall temperature, and the rate of heat imput from the fire, recognizing that many light hydrocarbons will cool with pressure reduction

54 Kletz, T., *Protect pressure vessels from fire,* Hydrocarbon Processing, August, 1977, pp. 98-102

55 Paruit, B. & Kimmel, W., Control blowdown to the flare, Hydrocarbon Processing, October 1979, pp. 117-121; also see Sonti, R., *Practical design and operation of vapor-depressuring systems,* Chemical Engineering, January, 23, 1984, pp. 66-69; the author of this present work participated in the peer review process for the referenced technical article when Mr. Sonti was employed with Bechtel Petroleum Inc.

56 API RP 521, Guide for Pressure-relieving and Depressuring Systems, American Petroleum Institute, Second Edition, September, 1982, p.18]

57 For a review of the historical development of the empirical equations used to determine heat absorption rates in vessels exposed to fire, beginning in the mid-1920's, see *Formulars Used for Determining Heat Absorption From Fire,* API RP 520, *Recommended Practice for the Design and Installation of Pressure-Relieving Systems in Refineries,* Part I--Design, Fourth Edition, 1976, Appendix A, pp. 27-31; also see pp. 10--16 for heat transfer basis

58 Steel Construction Institute (U.K.), *Interim Guidance Notes for the Design and Protection of topside Structures Against Explosion and Fire,* Document No. 243, First Edition, January, 1992, Tables 4.1 and 4.2, pp. 4.9-4.10

59 Many older GOM platforms have relief valves and depressuring valves discharging directly to atmosphere. The validity of extrapolating guidelines for refinery pressure-relieving and depressuring systems for production platform operations using closed disposal systems, solely based on experience, is thought to be questionable. Further research is encouraged in this area.

60 Heitner, I., Trautmanis, T., and Morrissey, M., *When Gas-filled vessels are exposed to fire...,* Hydrocarbon Processing, November, 1983, pp. 263-268

61 In the 1940s the American Petroleum Institute conducted a survey among its members to determine what practices were being followed for sizing relief valves on large pressure vessels. Due to widely varying answers, API appointed a Subcommittee on Pressure Relieving systems to develop design practices for determining relief capacity. Simultaneously, the Liquefied Petroleum Gas Association (LPGA) appointed a committee to determine relief valve sizing. Mr. Heller was a member of both the LPGA committee as well as a member of the National Academy of Sciences committee that studied pressure relief requirements for mairne cargo bulk liquid carriers for the U.S. Coast Guard. At the time of his paper, he was the only remaining member of one of the two original pressure relieving committees working this problem. His

paper is both historically interesting and explanatory, providing insight into today's present practices.

62 also see Heller , F.J., Safety Relief Valve Sizing: API Versus CGA Requirements Plus A New Concept For Tank Cars, Phillips Petroleum Company, Bartlesville, OK, circa 1983, pp. 123-140

63 When the vapor depressuring flow rate exceeds the normal vapor flow rate in a pressure vessel, or if the depressuring rate is additive to the normal vapor flow rate, as may be the case when depressuring is effected without vessel isolation, considerable liquid carryover is likely. Therefore, header designs should account for two phase flow and liquid knockout provisions should be sized accordingly

64 For information on current research projects addressing characterization of platform fires and structural response, refer to Appendix A, *Survey of Current Research*, Report of Task I, Define and Characterize the Offshore Fire Problem, Improved means of Offshore Platform Fire Resistance, (UCB Eng-7429), A report to the Minerals Management Service, University of California, College of Engineering, W.E. Gale, Jr., Principal Author, November 1, 1991

65 Thermal inertia accounts for the mass of a structural element, *m*, and its thermal absorptivity as measure by $(\rho k C_p)$

66 O'Neill, J., *Development of Blowout Fire Suppression Technology*, a Letter Report, United States Department of Commerce, National Bureau of Standards, (undated) circa 1981, p. 5

67 Ibid., p. 6

68 American Petroleum Institute, Recommended Practice 2G (RP 2G),*Recommended Practice for Production Facilities of Offshore Structures*, First Edition (withdrawn), January, 1974, p.4

69 For a discussion of blast resistance considerations, refer to § 9.3.3

70 NFPA 251, Standard Method of Fire Tests of Building Construction and Materials, National Fire Protection Association, 1985; also known as ASTM E-119 and UL 263

71 The fire rating of bulkheads onboard merchant ships is regulated by the Safety of Life at Sea (SOLAS) regulations of the International Maritime Organization (IMO) based on ASTM E-119 fire tests; e.g., an A-60 rating is a one hour fire resistive bulkhead

72 Buck, M and Belason, E., *ASTM Test for Effects of Large Hydrocarbon Pool Fires on Structural Members*, Plant/Operations Progress, Vol. 4, No. 4, October, 1985, pp. 225-229

73 Berhinig, R., (Underwriters Laboratories, Inc., Northbrook, Ill.) *Fire Resistance Test for Petrochemical Facility Structural Elements*, Plant/Operations Progress, Vol. 4, No. 4, October, 1985, pp. 230-233

74 SOLAS hydrocarbon fire test ratings for firewalls are H-0, H-60, and H-120; all designations require stability and integrity be maintained for 120 at least minutes. In addition, H-60 and H-120 impose temerature rise limitations on the unexposed face for 60 minute and 120 minute exposures respectively.

75 American Petroleum Institute, API Publication 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*, First Edition, July, 1988

76 AAmerican Petroleum Institute, Recommended Practice 500B (RP 500B), *Recommended Practice for Classification of Locations for Electrical Installation at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms*, Third Edition, October 1, 1987, p.9

77 Note that API RP 500B was combined with RP 500A and RP 500C into a unitized API recommended practice, RP 500, *Recommended Practice for Classification of Location for Electrical Installations at*

Petroleum Facilities, First Edition, June 1, 1991. Revisions made at this time were primarily editorial and do not affect technical considerations as contained in previous practices

78 API RP 500B, op.cit., Section 4, Classification Criteria, pp. 12-18

79 Based on information from WOAD [ref. Veritec, *Worldwide Offshore Accident Databank, Statistical Report, 1988,* Hovik, 1988, ISSN 0801-5929] data for the period of 1980-1987 (pre-Piper Alpha) for fixed platform operations. It was found that the number of accidents for GOM platforms was almost exactly one order of magnitude lower than that for North Sea platforms (8.7 v. 87.05 accidents/1000 operating years), and that lives lost was lower by a factor of more than 12. As discussed in Chapter 3 of this present work, the Marine Board has found that differences in ventilation is a primary contributing factor to higher loss rates

80 API RP 500B, op.cit., p. 7 & 14

81 See NFPA 30, *Flammable and Combustible Liquids Code,* National Fire Protection Association, Definitions (page varies with edition, for example NFPA 30-1983, p. 30-16)

82 U.S. Code of Federal Regulations, 30CFR250.123, July, 1992

83 The 1986 edition of API RP 14C calls for either 12 air changes per minute or 1.5 cfm/ft^2 of floor area, whichever is greater [ref.: API RP 14C, *Recommended Practice for Analysis, Design, Installatin and Testing of basic Surface Safety Systems for Offshore ProductinPlatforms* (RP 14C), American Petroleum Institute, Fourth Edition, September 1986, p.82

84 Gale, Jr., W., *Module Ventilation Rates Quantified,* Oil and Gas Journal, December 23, 1985, pp. 39-42

85 Experience has shown that, regardless of ventilation rate, the occurrence of flammagle gas or vapor liberation from some apparatus is so infrequent that such locations may be unclassified. For example, locations where flammable substances are contained in all-welded closed piping systems or continuous metallic tubing without valves, flanges, or similar devices. Refer to API RP 500B, Third Edition, Oct., 1987, p. 13 § 4.5 for other examples

86 It is impractical to design mechanical ventilation systems to respond fast enough and with sufficient capacity to handle such occurrances; this is one reason why simple open deck structures will always be inherently safer than enclosed modules. Large uncontrolled releases that occur in the open have a greater likelihood of dissapating harmlessly in the atmosphere than if enclosed in a series of connected modules

87 National Fire Protection Association, NFPA 69, *Explosion Prevention Systems,* 1978 edition, p. 69-38

88 For further information on the use of fugitive emissions as a basis for determining the adequacy of ventilation for petroleum production facilities see Minutes of the Spring Meeting of the API Committee on Safety and Fire Protection, Attachment #7, *API 500B 1987 Revision -- Key Issues Proposed By Chevron Corporate Fire Protection Staff,* March 31-April 2, 1987 in Kansas City

89 Subsequent to API's adoption of the fugitive emission methodology for ventilation rate determination, the Institute of Petroleum (U.K.) and Canadian electrical authorities have also recognized this approach. (See Model Code of Safe Practice in the Petroleum Industry, Part 15, *Area Classidication Code for Petroleum Installations,* Institute of Petroleum, London, March, 1990, pp. 67-68]. In 1989, the Province of Alberta, Electrical Protection Branch, granted Esso Resources Canada Ltd. permission to electrically classify their Leduc Oil Field Gas Compressor Building Class I Division 2 (instead of Division 1) based on fugitive emission calculations. Contrary to API, Alberta authorities denied recognition of "Limited Ventilation" and accepted the fugitive emission calculation methodology as the basis for determining "Adequate Ventilation." (personal correspondence from Sidney Woo to W. Gale, October 5, 1989]

[90] For further information on ventilation rate determination, refer to Appendix A, B and C of API 500B, 1987

[91] National Fire Protection Association, NPFA 68, *Guide to Venting of Deflagrations*, 1988

[92] Offshore module combustion rates and flame speeds during an explosion can be expected to greatly exceed those used by standard empty enclosure venting guidelines which should not be relied on to reduce blast overpressures; see *Interim Guidance Notes for the Design and Protection of Topside Structures Aganist Explosion and Fire,* Steel Construction Institute (U.K.), First Edition, January, 1992, p 3.3

[93] Much as been written on UVCEs, their cause and effects. See, for example: Gugan, K. Unconfined Vapor Cloud Explosions, Institute of Chemical Engineers, (U.K.), George Godwin Ltd., Reading, U.K., 1979; also Prugh, R. et al., Guidelines for Vapor Release Mitigation, Center for Chemical Process Safety, American Institute of Chemical Engineers, N.Y., 1988

[94] American Petroleum Institute, Recommended Practice 750 (RP 750), Management of Process Hazards, First Edition, January, 1990, Appendix A, p.11

[95] Davenport, J., and Lenoir, E., A Survey of Vapor Cloud Explosions, Process Safety Progress, Vol. 12, No. 1, American Institute of Chemical Engineers, January, 1993, pp.12-33; note that this is an update of the previous surveys performed and published in 1977 and 1983, as referred to in API RP 750.

[96] Under the right conditions, as the reaction proceeds with ever increasing speed, subsequently generated pressure waves traveling faster than previously generated waves, overtake the earlier waves and form a pile-up, e.g, a moving pressure step or shock wave traveling at sonic speed. This is commonly considered the transition point of a deflagration into a detonation. Detonations propagate at supersonic velocities and can produce pressures 60-100 times above the initial pressure. Detonations are promoted by vessels, pipelines and ducts with high length-to-diameter ratios, e.g, above 10. See Hazards of Air in Refinery Process Systems, Standard Oil Company (Indiana) Booklet No. 2, Third Edition, 1959, pp.21-38

[97] *Special panels relieve explosion pressure,* Ocean Industry, April/May, 1990, p. 62

[98] Stephens, M., *Minimizing Damage to Refineries from Nuclear Attack, Natural, and Other Disasters,* The Office of Oil and Gas, U.S. Department of the Interior, February, 1970, pp. 116-134

[99] Tunkel, S., *Estimating Blast Effects from Explosion,* API Committee on Safety and Fire Protection Paper No. 31, presented at the Spring Meeting of the American Petroleum Institute, April 10, 1985, Nashville, TN, p.2

[100] Minimizing Damage to Refineries from Nuclear Attack, Natural and Other Disasters, op. cit., p. 75

[101] DuPont Fire Protection Engineering Standard, F1K, Explosion Fundamentals, Subcommittee No. 28, Issued January, 1978, Reaffirmed June, 1982, p. 7 of 25

[102] Tunkel, S., *Estimating Blast Effects from Explosion*, op. cit.

[103] DuPont Fire Protection Engineering Standard, op. cit., Table 4, p. 17 of 25

[104] Research being conducted by the Joint Industry Project on Blast and Fire Engineering for Topside Structures indicates that, in an offshore platform module, the combustion rate and flame speeds of vapor cloud explosions may be far greater than that expected for a comparative empty enclosure due to the pronounced effects that obstacles and congestion has on inducing turbulence. Flame speeds may be so high that the inertia of the surrounding atmosphere and the drag effects on module piping and equipment is

sufficient to generate severe overpressures, **even in the absense of confining walls.** See Interim Guidance Notes for the Design and Protection of Topside Structures Against Explosion and Fire, Steel Construction Institute (U.K.), Document No. 243, First Edition, January, 1992, p. 3.3

105 Tunkel, S., *Estimating Blast Effects from Explosion*, op. cit., p.3

106 Allan, D, et al., Influence of Explosions on Design, Loss Prevention, American Institute of Chemical Engineers, Volume 2, 1968

107 personal correspondence to W. Gale, Jr. from B. Hjertager, August 3, 1987

108 For further information on the computational basis of FLACS, see Three-Dimensional Modeling of Flow, Heat Transfer, and Combustion, Bjorn H. Hjertager, (Chapter 41), Handbook of Heat and Mass Transfer, Gulf Publishing Co., 1986, pp. 1303 - 1350

109 For a review of empirical, phenomenological (integral) and numerical models currently in use to predict blast overpressures and loadings, see See Interim Guidance Notes for the Design and Protection of Topside Structures Against Explosion and Fire, Steel Construction Institute (U.K.), Document No. 243, First Edition, January, 1992, pp. 3.4 - 3.9

110 Bakke, J. and Storvik, I., *Simulation of Gas Explosions in Module C, Piper Alpha*, Chr. Michelsen Institute, Report CMI No. 25218-1, October 27, 1988, comprising Annex No. 3 of Piper Alpha Technical Investigation, Further Report, J.R. Petrie, Director of Safety, Department of Energy (U.K.), December, 1988

111 Levine, R. et al., Guidelines for Safe Storage and Handling of High Toxic Hazard Materials, American Institute of Chemical Engineers, Center for Chemical Process Safety, 1988, p.76

112 Veritec, Offshore Reliability Data Handbook (OREDA), Pennwell Books, First Edition, 1984

113 Balkey, K., *ASME Research Project on Risk-Based Inspection Guidelines,* American Petroleum Institute Committee on Safety and Fire Protection, Technical Paper #2366, presented at the spring meeting on April, 13, 1989, Tulsa, Oklahoma

Chapter 10

SAFETY MANAGEMENT SYSTEM ASSESSMENT (SAMSA)

As discussed in Chapter One and illustrated in **Figure 1-1**, the Safety Management System provides the means to integrate and execute those aspects of platform design and operations that directly and indirectly influence meeting safe operating goals. Chapter 10 further describes how FLAIM assesses the adequacy of the Safety Management System and explains why SAMSA is considered to be among the most important component of platform safety assessment.

Bea and Moore[1] have described what has come to be known as the "80-80" rule, i.e., as previously discussed herein, over 80% of all high consequence accidents that occur offshore are the result of compounded human and organizational error (HOE), and of these, 80% occur during or as a result of ongoing operations. SAMSA complements and completes the assessment of those vitally important human and organizational risk factors that go beyond those already discussed in Chapter 7, Operational/Human Factors Assessment (OHFA).

Figure 10-1 below, illustrates the relationship of HOE factors to accident causations in an offshore environment. It is important to understand that errors (leading to accidents) not only occur discretely, e.g., within any given error category, such as the result of system faults or procedural errors, but also frequently occur at boundary interfaces.

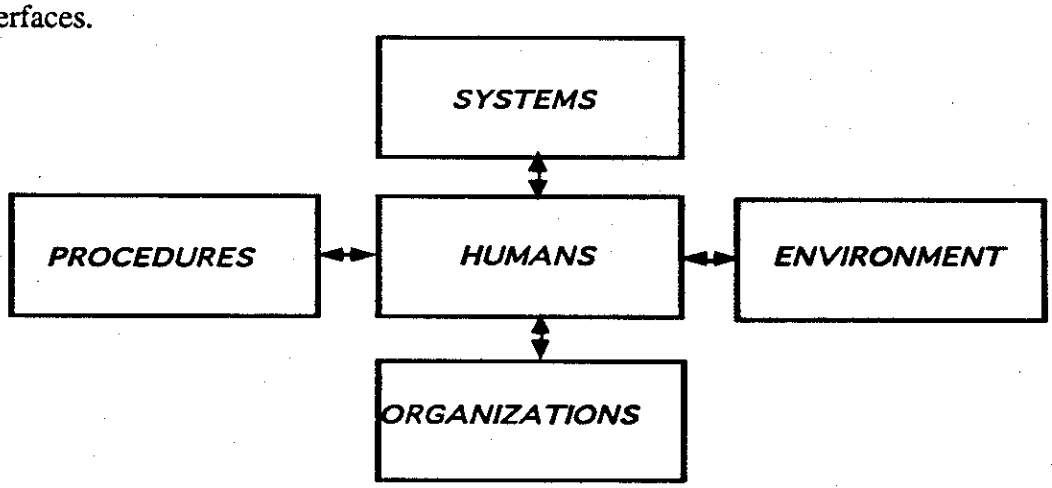

Figure 10-1
Relational Influence of HOE

The Safety Management System Assessment seeks to assess the adequacy of management's ability to identify and respond to root-cause errors stemming from human and organizational factors, such as those leading to the Piper Alpha loss. Bea and Moore[2] have developed a taxonomy of human and organizational errors for marine related accidents. Preceded by early research by Paté-Cornell & Bea (1989)[3] and Reason (1990),[4] the HOE taxonomy addresses both error types and underlying/compounding causes. Thirteen error classifications have been identified by Bea and Moore that can be subdivided into four general categories, all of which are subject to external environmental influences. In FLAIM's SAMSA component, factors identified in the HOE taxonomy not previously addressed in OHFA (Chapter 7) are accounted for using four general assessment categories as described below.

Figure 10-2 illustrates the process of assessing the adequacy of the Safety Management System (SAMSA) developed for FLAIM. The four general areas of evaluation identified for assessment are: **Management Systems, Fire (Emergency) Preparedness, Training, and Management of Change.** Each of these aspects of SAMSA are considered in the FLAIM methodology to be interdependent and essential to achieving fire and life safety operating goals.

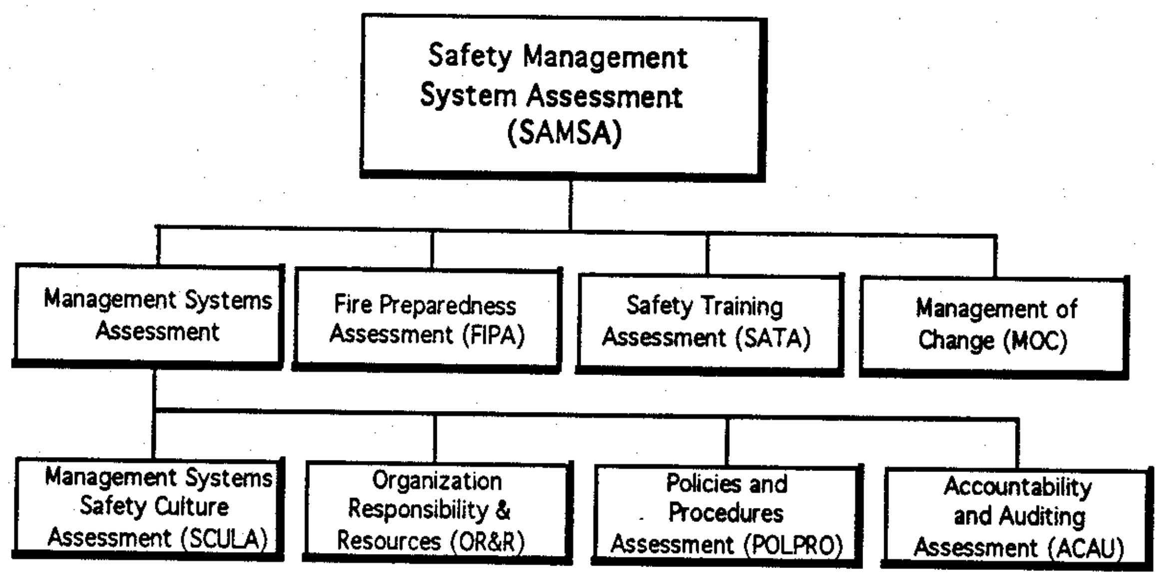

Figure 10-2
Safety Management System Assessment Modules

10.1 *MANAGEMENT SYSTEMS ASSESSMENT*

Management Systems evaluates the efficacy in which corporate safety policies and plans are executed by management, recognizing that if risk management is to be effective, it must be effectively communicated to and carried out by line management.[5] Assessment of Management Systems evaluates organizational components affecting management's ability to execute its risk management program.

Four sub components have been identified in FLAIM as the most significant factors relevant to the assessment of Management Systems: management systems safety culture (SCULA); organization responsibility & resources (OR&R), including assessment of budget allocations for safety management functions; policies and procedures assessment (POLPRO); and accountability and auditing assessment (ACAU). These four areas together are considered pivotal to a successful risk reduction and management program, and in fact, are a compilation of the (fourteen) essential elements of Total Quality Management (TQM) as expounded by Deming.[6] They are the sole responsibility of top management and can only be carried out by top management; they serve as direct indicators of management's awareness of and commitment to continued safe operations.[7]

10.1.1 Management Systems Safety Culture Assessment (SCULA)

The overall "safety culture" or attitude that permeates throughout the organization, from upper management to shift foremen, is crucial to safe operations.[8] The safety culture of an organization can be expressed in terms of its commitment to safety and the resources that are made available to meet this commitment. This in turn affects all other aspects of safety management, as classified by Bea and Moore, [9] and as discussed by Deming.

The single most essential element stressed by Deming's fourteen point approach to Total Quality Management is his last program element[10] -- creating a structure and environment in top management that is conducive to continually cultivating and building upon on the other thirteen points, e.g., develop a "corporate culture" of quality that permeates down and throughout the entire organization. He seeks to develop a "constancy of purpose towards improvement" in which management's (new) philosophy embraces bold (new) concepts aimed at empowering the worker, creating organizational incentives encouraging and rewarding self-improvement, eliminating worker fear (to do the right thing) and removing barriers to improving quality and safety, e.g., imposed production quotas. FLAIM's SCULA component, together with OR&R and the other Management System components, identify and assess key indicators of management's awareness and commitment to these ideals.

10.1.2 Organizational Responsibility & Resources (OR&R)

As demonstrated by the current trend in the GOM, large offshore leaseholders (major oil companies) tend to sublet (farm out) older fields with declining production rates and rising maintenance costs to smaller operators who can continue to realize profitable operations due to lower overhead costs. The Marine Board's Committee on Alternatives for Inspection (CAI) of OCS Operations reported[11] that in a five year period in the mid-1980's, the number of operating companies with less than six leases in the GOM increased more than 325%. This trend is continuing today as many large companies are abandoning their operations in the GOM in favor of overseas opportunities.

The CAI found that the safety implications of this trend is undocumented, but there are certain characteristics of small companies that may affect safety risks:

- small operators typically have no in-house safety staff and minimal technical engineering personnel to support field work or train field personnel in safe operations

- small operators are heavily dependent on contract labor and expertise, and normally provide little or no onsite operator supervision

- many small companies have limited "worry-budgets" (a term coined by Professor R.G. Bea to denote resources for safety expenditures), and may tend to defer costly safety measures, e.g., be less risk-adverse than larger companies.

These considerations tend to make smaller operators more apt to adopt a "compliance mentality" towards safety rather than moving forward with an aggressive, proactive safety management system approach. FLAIM seeks to identify weak safety culture environments by asking questions about: the company's safety and loss prevention staff relevant to the number of platforms being operated; its position in the organization and reporting authority; the percent of operating budget allocated to safety related activities, including training, maintenance, and testing of safety equipment; and the extent to which contract labor is employed to operate and maintain platforms, as well as the degree of supervision and training provided by the operator.

10.1.3 Company Policies and Procedures (POLPRO)

An important component of Management Systems is the extent to which the operating company has committed its safety policies and practices to written instruction. Written instructions are the instrument by which safety policies, goals, and management's commitment are communicated throughout and beyond the organization, e.g., the means for articulation of the safety culture. Without written policy goals and explicit instructions on how to achieve those goals, the course of platform safety goes uncharted.

FLAIM was developed with the recognition that attitude alone is not enough to elicit safe behavior.[12] POLPRO asks if the platform operator has a written policy establishing definitive safety objectives, goals, practices and the means to monitor, measure, and improve meeting safety targets.

POLPRO accounts for the status of written, up-to-date operating instructions for all topside systems and process components, including startup procedures, normal and temporary operations, emergency operations including emergency shutdowns (for each level of shutdown), and black-start restarts from complete shutdowns of all platform operations and power sources. Individual startup/shutdown and operating instructions for pumps, compressors, fired heaters, should be explicit to the machine in its "as-built" (as-installed) condition. As required by OSHA for onshore facilities, these procedures should contain information on occupational safety and health considerations.[13, 14]

A written Safe Work Practices (SWP) Manual should cover many routine tasks including: line and vessel opening/entry operations, lockout and tagout procedures, confined space entry, hot work and cutting operations, inerting and purging practices, heavy lifts and crane operations, sampling and sample connections, opening of drains and vents, use of personal protective clothing and gear, etc. The Permit to Work procedure should be clearly explained both in concept and in explicit requirements. In addition, accident investigation instructions and forms may be included in the SWP manual or provided as a separate document in the emergency response plan. FLAIM asks if is there is a SWP Manual and if it is up to date and complete.

Emergency Response Plans are also an important element included in POLPRO. Most platforms will already have written plans for oil spills and for emergency evacuation as required by MMS and the USCG. SCULA seeks to assess the adequacy of these procedures and asks about the frequency of emergency response drills and the provision of improving written plans based on feedback from lessons learned in rehearsals.

10.1.4 Accountability & Auditing (ACAU)

Successful implementation of the platform's safety management program depends to a large extent on the means used to measure progress in meeting safety goals and to effect improvements in program execution. Accountability is required to effect change and realize improvements. The ACAU element of SCULA seeks to determine if the safety program is being effectively carried forward with the requisite level of management support and accountability necessary for meaningful implementation. This includes auditing of the safety assurance and written reports to management.

An important indicator in safety culture evaluation has been identified by FLAIM as an operating company's "lessons-learned" program. ACAU asks the operator about the disposition of information collected in near-miss and accident reports. A pro-active approach taken in analyzing and learning from operational experiences, and then following through by communicating this information and revising company practices accordingly, is one indicator of a strong safety culture. Conversely, compliance with accidents report requirements as mandated by MMS OCS Orders and committing the information to a file cabinet without further thought is clear evidence of a "compliance mentality" as described by the CAI.[15]

10.2 *FIRE PREPAREDNESS ASSESSMENT (FIPA)*

The FIPA is a measure of a operating crew's preparedness and ability to effectively deal with developing emergency situations. FIPA does not address hardware aspects of preparedness; these are accounted for in the Risk Reduction Measures Assessment (RIRA). FIPA is the complementary component to RIRA and evaluates the human and organizational factors deemed critical to controlling a developing fire scenario.

The extent of human intervention necessary to successfully terminate a developing situation depends to a large extent on the platform design, its susceptibility to loss of containment events, provisions for automatic detection, control, and shutdown, and the platform's inherent vulnerability, or conversely, its robustness to resist thermal impact. There are two terms in the equation for assessing fire preparedness, each containing several variables.

The first term evaluates management's understanding of exactly what role the crew is expected to play in any given emergency situation. The assessment seeks to address issues of response expectancy with a view to determining whether or not an unrealistic reliance and dependency has developed on a crew's ability to respond.

For example, identification of critical manual tasks necessary for successful fuel-source isolation in a LOC event, when compared to concurrent demands for fire-fighting, communications, and general platform shutdown, may show an inordinate dependence on human response in some scenarios. Quite often, emergency demands placed on crew members tend to evolve and change in response to platform modifications and expansions. The cumulative effect may exceed reasonable response expectancies, but go unrecognized for lack of an emergency operability study.

The second term in the equation addresses the crew's preparedness and capability to carry out those essential demands placed on it under various emergency scenarios, assuming the demands are reasonable as evaluated above. This requires and assessment of the crew's knowledge and understanding of what is expected for a given situation, their ability and willingness to effect their duties, and the capability to demonstrate this through hands-on hypothetical training exercises for emergency situations.

For example, the operators at the Three Mile Island Nuclear Plant had been trained that the pressurizer on the pressurized water reactor was a valid representation of coolant inventory. Their training had not considered the possibility for a leak on top of the pressurizer, e.g., their training model for emergency events failed to consider all possible event causes and consequences. When the pressurizer leak occurred, the operator's diagnosis of the problem was based on an inaccurate model of what was actually happening -- they interpreted a rise in pressurizer level as an indication of excessive coolant in the system, which caused them to dump coolant, eventually leading to a meltdown.[16]

10.3 Safety Training Assessment (SATA)

Safety Training Assessment is intended to evaluate the overall level of formal personnel training and operator qualifications. Recognizing that human and operational error is the primary cause of offshore accidents, the adequacy of training at all levels throughout the organization is assessed -- both from an operational standpoint and from a risk aversion/cultural standpoint.

Well trained operators, inspectors, maintenance personnel, and supervisors are essential to workplace safety. Further, it is recognized that training must necessarily be viewed as a dynamic process, accounting for an ongoing effort to maintain personnel awareness and cognizance of a safety culture. Beyond this however, the overall attitude and culture of management must necessarily be assessed with regard to the inherent reward system of the organizational structure.

Following a recent major fire loss involving operator error, one major petroleum company undertook an extensive study[17] to better understand the factors contributing to the incident. The loss stemmed from the operators' inability to effectively deal with a large number of incoming alarm signals from a sophisticated distributed control system (DCS) during an emergency. In comparing two similar facilities, it was found that in the facility which suffered the loss, the average experience level of control room operators was only seven years, equivalent to a 14 percent attrition rate, and that operating personnel were only about 50 percent cross-trained in the various duties performed by all operating personnel. This compared to very high levels of experience and cross-training, and a corresponding low attrition rate at the sister facility in which a similar DCS system was installed and operated without problem.

Personnel responsible for platform production operations and for installing, inspecting, testing and maintaining safety devices and systems are required by MMS

Orders[18] to receive formal training from certified instructors. Course content, length, testing and instructional quality, and documentation are prescribed by federal statues. These requirements are based on API RP T-2, *Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work with Anti-Pollution Safety Devices*, which covers instructions on safety equipment and on responding to various LOC events, including fire, as well as use of emergency support equipment and systems.

In addition, platform personnel should be trained to API RP T-4, *Recommended Practice for Training of Offshore Personnel in Non-operating Emergencies,* which covers training for non-process critical emergencies.

Crane operations are a particular high risk activity offshore; crane operators should be trained to API RP 2D, *Recommended Practice for Operation and Maintenance of Offshore Cranes.*

Well control training is covered by API RP T-6, *Recommended Practice for Training and Qualification of Personnel in Well Control Equipment and Techniques for Completion and Workover Operations on Offshore Locations.*

Platforms producing hydrogen sulfide gas should include safe operating procedures specific to H_2S emergencies. These are contained in both the OCS Orders and two API Recommended Practices -- RP 49, *Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide*, and RP 55, *Recommended Practice for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide.*

Training sessions must not only cover normal operating procedures and emergency response planning, but should also include safe work practices. This should include routine review of the work permit system requirements as well as specific training in each work practice, e.g., hot tapping, hot work, lockout/tagout, etc. If contract personnel are used to perform MARW activities, SATA seeks to ensure that these personnel are adequately trained and qualified to perform their assigned duties, as well as being trained for emergency response.

10.4 *MANAGEMENT OF CHANGE (MOC)*

As discussed in § 7.3, *Operational Management of Change*, a typical production platform is subject to continual change driven by a desire to improve efficiency, enhance operability and safety, or implement technical and mechanical innovations as field production characteristics change. New air and water quality standards may be enacted that require modifications of process systems; improvements in equipment may become available that effect operating cost savings, or additional onboard equipment may be needed for enhanced oil recovery programs.

Changes in operations may routinely occur, such as periodic wireline operations or other downhole activities that, in turn, may increase the overall level of LOC and fire risk on the platform until the job is completed. Changes in platform personnel can also increase the likelihood of human error. It can be said that, from a global standpoint, the overall level of platform risk at a particular point in time, e.g., real-time risk at any time $\mathbf{R}_\tau$ or *effective risk*, varies from a normalized baseline risk, $\mathbf{R}_b$, or residual risk, in accordance with nature of the change taking place. $\mathbf{R}_b$ can be expected to vary with time due to aging and deterioration in accordance with the characteristics of the facility. Changes of a permanent nature, such as facility modifications, may ultimately be realized in a new value for $\mathbf{R}_b$, whereas changes of a temporal nature, such as conducting a high risk activity for a finite time period, will cause an aberration of the level of effective risk, $\mathbf{R}_\tau$.

The goal of risk management programs is to manage how risk may change over the operational lifetime of a platform, e.g., <u>the key to successful risk management is successfully managing change</u>. Both physical changes and personnel changes, and operational changes can greatly impact fire and life safety risks. In the recent past, however, the management of change has not been generally recognized as a factor that must be continually and systematically managed.

FLAIM's *SAMSA* component seeks to evaluate the adequacy of the management plan's program for managing change. In Management of Change Management Program (*MOCMAP)*, FLAIM asks if the prerequisite elements of a MOC management program, as identified by API RP 75,[19] are established and implemented in written procedures. This should include the requirement for a hazards analysis of the safety, health and environmental implications of the proposed change, including its direct local impact and global ramifications to the overall risk level of the platform. Such an evaluation may be performed by using FLAIM's methodology to assess these impacts.

[1] Bea, R. and Moore, W., *Management of Human and Organizational Error in Operational Reliability of Marine Structures*, Second SNAME Offshore Symposium: Design Criteria and Codes, Houston, TX, April, 1991

[2] Bea, R. and Moore, W., A Practical Human Error Taxonomy for Marine Related Casualties, Management of Human Error in Operations of Marine Systems -- A Joint Industry Project, Report No. HOE-92-3, Department of Naval Architecture & Offshore Engineering, University of California, Berkeley, June, 1992.

[3] Paté-Cornell, M., & Bea, R., *Management Errors and System Reliability: A Probabilistic Approach and Application to Offshore Platforms*, October, 1989, published in Risk Analysis, Vol. 12, No. 1, March, 1992.

[4] Reason, J. How to Promote Error Tolerance in Complex Systems in the Context of Ships and Aircraft, Department of Psychology, University of Manchester, U.K., (undated); also see Human Error, New York: Cambridge University Press, 1990

[5] Bergmann, E.P., Blaylock, N.W., et al., *Risk management success calls for hard decisions*, Hydrocarbon Processing, Gulf Publishing, August, 1992, p. 90

[6] Deming, W.E., Quality, Productivity, and Competitive Position, Massachusetts Institute of Technology, Center for Advanced Engineering Study, Cambridge, MA, 1982, pp. 16-49.

[7] Ibid., p. 16

[8] Commission on Engineering and Technical Systems, *Alternatives for Inspecting Outer Continental Shelf Operations*, Marine Board, National Research Council, National Academy Press, Washington, D.C., 1990, p. 5

[9] Bea, R. and Moore, W., *Human and Organizational Errors in Operations of Marine Systems: Occidental Piper Alpha and High Pressure Gas Systems on Offshore Platforms*, OTC 7121, Offshore Technology Conference, May, 1993, Houston, p. 4, Figure 1, Human and Organization Error Classification

[10] Deming, W.E., op. cit., pp. 16-17

[11] Alternatives for Inspecting Outer Continental Shelf Operations, Marine Board, Commission on Engineering and Technical Systems, National Research Council, National Academy Press, Washington, D.C., 1990, p. 14

[12] Krause, T, and Sloat, K., *Attitude Alone Is Not Enough*, Occupational Health & Safety, Medical Publishing Inc., Waco, TX, January, 1993, pp. 26-31

[13] Arnold, K., and Roobaert, N., *Actions Needed to Comply With API 750 Management of Process Hazards for Offshore Facilities*, SPE 22803, Society of Petroleum Engineers, presented at the 66th Annual Technical Conference and Exhibition, Dallas, TX, October, 1991, p.447

[14] See API RP - 54, Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Service Operations, American Petroleum Institute, May, 1992, for information addressing drilling and oil well service operations

[15] Alternatives for Inspecting Outer Continental Shelf Operations, op. cit., p.5

[16] Strohbar, D.A., *Human Factors in Distributed Process Control*, paper presented to the American Petroleum Institute Operating Practices Committee Executive Session, Seattle Washington, Oct. 6, 1987

[17] Spurlock, M.G., *Control Operator Overload During Emergency Situations*, paper presented to the American Petroleum Institute Operating Practices Committee Executive Session, Seattle Washington, October 6, 1987

[18] U.S. Code of Federal Regulations, 30 CFR Subchapter B – Offshore, Part 250.214, Oil and Gas and Sulphur Operations in the Outer Continental Shelf, Production Safety System Training, July, 1992

[19] API RP 75, Recommended Practices for Development of A Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities, American Petroleum Institute, Eighth Draft, November, 1992, pp. 11-13

Chapter 11

FLAIM ALGORITHM METHODOLOGY

The actual algorithm used in combining the various risk factors into a single topside risk index is described in this chapter, including a discussion on the relative weighting of each and the rationale used in their combination. Detailed user instructions and an example for running FLAIM on a personal computer are given in Appendices A and C respectively. Appendix C presents an example of FLAIM's implementation on a hypothetical offshore production platform based on an actual design. These appendices address the steps involved in calculating the individual assessment module risk factors and the overall topside risk index. An example of a computer generated spreadsheet is provided for illustration in Appendix C.

Chapter 11 describes the functional structure and rationale of the algorithm derived for driving FLAIM. Section 11.1 addresses the input value forms - how values are presented in the FLAIM input structure (binary - "yes/no"; grade points; grade point credits - "weighting"; and values - numbers of...).

Questions within the model have been categorized in accordance with the influence they bear upon the relative risk of platform fire and life safety. Section 11.2 describes the approach developed to evaluate or "weight" the relative importance of each discretized bit of input data, and how users may adjust the algorithm to reflect the hierarchical importance of data based on the specific regional, operational, and design factors unique to the platform.

Section 11.3 describes the algorithm function development using binary, grade point, value, and weighting input parameters. The functions are the basis from which an overall *grade point average* (GPA) is generated. Section 11.4 illustrates the algorithm function with a short example.

11.1 *FLAIM PRIMARY VALUE INPUT STRUCTURE*

FLAIM's input data is requested in one of three primary forms: (1) binary, (2) qualitative letter grades, and (3) numerical values. The following is an explanation of these input values.

11.1.1 Binary Input Data

The binary value system (β_{ij}) is presented by answering "Yes" or "No" (or "Good" or "Bad" -- see Eqn. 11.1) to the presented questions. The input value returns a value of 0 or 1 dependent upon the assignment of the value to the answer (Eqn. 11.1). Any question that is to be answered "Yes" or "No" in the FLAIM spreadsheet program is followed by - "(Y/N)."

$$\beta_{ij} = \begin{cases} 0 \text{ if "Yes"} \\ 1 \text{ if "No"} \end{cases} \quad \text{or} \quad \beta_{ij} = \begin{cases} 0 \text{ if "No"} \\ 1 \text{ if "Yes"} \end{cases} \tag{11.1}$$

for question i, assessment j.

11.1.2 Letter Grades

The grade point structure follows along the line of the grade point structures used in academia. The grade points range from "A" to "F" and are assigned numbers based upon the same 4.0 point grading system used in many academic grading schemes. The algorithm automatically assigns a numeric value to the grade point input provided by the user in the spreadsheet (see **Table 11-1**). Questions that directly use the grade point scheme in the spreadsheet are provided with a short description of what constitutes the selection of that grade. The grades are represented by $0 \leq \eta_{ij} \leq 4$ (risk assessment i, question j).

Table 11-1

Grade point scheme for platform risk factors and corresponding numeric values

A - "Excellent" condition of the risk contributing factor upon the platform fire and/or life safety **(4.0)**

B - "Good" condition of the risk contributing factor upon platform fire and/or life safety **(3.0)**

C - "Fair" condition of the risk contributing factor upon platform fire and/or life safety **(2.0)**

D - "Poor" condition of the risk contributing factor upon platform fire and/or life safety **(1.0)**

F - "Bad" condition of the risk contributing factor upon platform fire and/or life safety **(0.0)**

11.1.3 Numerical Values

Quantitative values (such as barrels of oil per day (BPD), millions of standard cubic feet of gas produced per day (mmscfd), size of operating crew, etc....) are numeric value inputs. The units prescribed for each input value is provided at the end of each question. This information is used in the assessment of the relative overall consequence level of the platform, as well as for evaluations of specific risk contributing factors.

11.2 *FLAIM WEIGHTING STRUCTURE*

To maintain consistency with the grade point scheme, all default input values are considered to range between 5.0 and 1.0. This is equivalent to the concept of the number of "units" that an academic course is worth. The greater the unit value, the greater the relative importance of that factor to the grading scheme.

The weighting structure of FLAIM's algorithm has two types of value inputs (ω_{ij}) (risk assessment i, question j): (1) direct input value assessment of weighing values, and (2) indirect input value assessment, e.g., values generated as part of the algorithm (see List of Symbols). Direct inputs are provided by the user's assessment of the relative importance of that particular factor to fire and life safety on any given platform. For example, the relative importance of the ability of personnel to escape via the sea for a platform in the Gulf of Mexico (GOM) may be considered a more vital aspect of the overall risk management plan than that of a platform located in the Gulf of Alaska (GOA). Conversely, in areas where weather can be extreme, "safe havens" for personnel may create a greater need (and importance) for firewalls with high levels of fire endurance since escape by water may not be a viable option.

Indirect value assessments can be made through summing the binary input values (β_{ijk}) which are made up of sets of sub-questions (see Appendix A). There can be between 2 and 23 sub-questions dependent upon the importance of the factor in question to fire and/or life safety.

Indirect value assessments are also functions of the numeric input values. These values are used to weigh the relative importance of fire and life safety risk. For example, if there is a small crew contingent aboard the platform, there is a smaller overall risk of injury or loss of life to personnel than if there was a large operating crew.

Or, for example, production rates (high or low) may have a great impact upon the loss of containment risk.

11.3 *THE FLAIM ALGORITHM VALUE STRUCTURE*

The primary algorithm structure is in the form shown in Equation 11.2. This general algorithm structure is similar to that of the academic grading scheme shown in Equation 11.3. The *grade point average* (GPA) is determined by summing the product of the grades and credits for each course (total of *p* courses) and dividing by the total number of credits. This value is the GPA.

$$\eta_j = \frac{\sum_{i}^{n} \omega_{ij}\, \eta_{ij}}{\sum_{i}^{n} \omega_{ij}} \tag{11.2}$$

$$GPA = \frac{\sum_{l}^{p} Credit_l\, Grade_l}{\sum_{l}^{p} Credit_l} \tag{11.3}$$

Sections 11.3.1 through 11.3.3 describe the numeric, binary, and grade point structures for each question used in FLAIM. **Table 11-2** summarizes the grading structure used for each value assignment type.

11.3.1 Numeric Value Range Assignments

The numeric value assignments have a pre-defined "value range" that determine the grading structure. Single-question numeric value assignments have direct value assignments. Multiple-question numeric value assignment questions use an averaging of values obtained from each sub-question. The user is asked to determine the range values that determine the grading structure based on the particular platform design and operation circumstances under scrutiny. FLAIM has been intentionally designed to allow either the user, or the consensus of a user's group,[1] to "calibrate" the risk assessment process.

11.3.2 Binary Value Assignments

The binary input value assignments are given dependent upon whether the question has a positive or negative impact upon fire and life safety values. Multiple-binary value assignments are averaged over the sub-questions to provide an overall grade for that particular question.

11.3.3 Grade Value Assignments

Single grade value assignments are based directly upon the A-F structure described in **Table 11-1**. The multiple sub-question value assignments use the A-F grading scheme. Similar to the numerical and binary multiple sub-question value assignments a mean grade value is used by averaging the grade over the number of sub-questions.

11.3.4 Question Weighting Assignments

According to **Table 11-3**, default values are assigned to the weight of each question dependent upon the level of the assessment. Certain FLAIM questions have already been pre-determined as suggested red-flag or "red-level" questions. These questions have been deemed to be particularly important to the safe operations of any offshore platform. Weighted value assignments for these factors are assigned by the user; those questions identified of particular importance may be assigned weighting values greater than those assigned at the Tiers 1-3 levels. However, FLAIM also allows the user to reassign the suggested default value of any selected question. If the assigned value exceeds the Tier 1 level value of 5, FLAIM automatically designates the question to a "red-level" status.

Factors from Tier 1 (initial screening) assessments are assigned the highest weighted values since they account for the most important contributing fire and life safety factors specific to the platform being assessed.[2] More detailed Tier 2 and Tier 3 questions are weighted correspondingly lower to reflect their <u>relative importance to overall</u> fire and life safety.

Table 11-2
FLAIM Algorithm Value Assignments

Numeric value assignments	Binary value assignments	Grade value assignments
Single question value assignments[3]	**Single question value assignments**	**Single question value assignments**
$\xi_{ij}(x) = \begin{cases} 4.0 & x < x_{ij}^1 \\ 3.0 & x_{ij}^1 \le x < x_{ij}^2 \\ 2.0 & x_{ij}^2 \le x < x_{ij}^3 \\ 1.0 & x_{ij}^3 \le x < x_{ij}^4 \\ 0.0 & x > x_{ij}^4 \end{cases}$	$\beta_{ij} = \begin{cases} 4.0 & \text{"positive impact"(Y / N)} \\ 0.0 & \text{"negative impact"(Y / N)} \end{cases}$	$\varepsilon_{ij} = \begin{cases} 4.0 & \text{if grade "A"} \\ 3.0 & \text{if grade "B"} \\ 2.0 & \text{if grade "C"} \\ 1.0 & \text{if grade "D"} \\ 0.0 & \text{if grade "F"} \end{cases}$
Multiple sub-question value assigments[4]	**Multiple sub-question value assigments**	**Multiple sub-question value assigments**
$\delta_{ijk}(y) = \begin{cases} 4.0 & y < y_{ijk}^1 \\ 3.0 & y_{ijk}^1 \le y < y_{ijk}^2 \\ 2.0 & y_{ijk}^2 \le y < y_{ijk}^3 \\ 1.0 & y_{ijk}^3 \le y < y_{ijk}^4 \\ 0.0 & y > y_{ijk}^4 \end{cases}$	$\rho_{ijm} = \begin{cases} 4.0 & \text{"positive impact"(Y / N)} \\ 0.0 & \text{"negative impact"(Y / N)} \end{cases}$	$\gamma_{ijn} = \begin{cases} 4.0 & \text{if grade "A"} \\ 3.0 & \text{if grade "B"} \\ 2.0 & \text{if grade "C"} \\ 1.0 & \text{if grade "D"} \\ 0.0 & \text{if grade "F"} \end{cases}$
$\delta_{ij} = \frac{1}{k}\sum_k \delta_{ijk}$	$\rho_{ij} = \frac{1}{m}\sum_m \rho_{ijm}$	$\gamma_{ij} = \frac{1}{n}\sum_n \gamma_{ijn}$

Table 11-3

Value Weighting Assignments According To Relative Importance

Relative Importance of Assessment to Fire or Life Safety	Assessment Level Assignment	Default* Weighting Value Assignment - ω_{ij}
Red-Level	Initial	Assigned by users
High	Tier 1	5 (5-4)
Moderate	Tier 2	3 (3-2)
Low	Tier 3	1 (2-1)

* Values in parentheses are value assignment ranges for each assessment level.

Though default values are assigned, FLAIM allows users to modify the value to reflect their preferences and experiences. Should a Tier 2 or Tier 3 factor be assigned a higher weight value comparable to that at a level higher than originally assigned, the user may reevaluate whether that contributing factor should be reassigned to a higher Tier level. At the user's discretion, these values may be changed to account for the relative importance of the question as determined by a consensus of the user group performing the analysis.

11.3.5 The FLAIM Algorithm

11.3.5.1 Individual FLAIM Assessment Grades

Equation 11.2 is used to determine the GPA for any assessment j (η_j). As shown in Equation 11.5, the grade value is assigned according to the question type. Each question is weighted according to its Tier level assignment except for the critical level where the weighted value is assigned by the users (τ_{ij}).

$$\eta_j = \frac{\sum_i^n \omega_{ij}\eta_{ij}}{\sum_i^n \omega_{ij}} \qquad (11.2)$$

where

$$
\eta_{ij} = \begin{cases} \xi_{ij} & \text{if question i, assessment j is single question numeric} \\ \delta_{ij} & \text{if question i, assessment j is sub - question numeric} \\ \beta_{ij} & \text{if question i, assessment j is single question binary} \\ \rho_{ij} & \text{if question i, assessment j is sub - question binary} \\ \varepsilon_{ij} & \text{if question i, assessment j is single question grade value} \\ \gamma_{ij} & \text{if question i, assessment j is sub - question grade value} \end{cases} \tag{11.4}
$$

$$
\omega_{ij} = \begin{cases} \tau_{ij} & \textit{if} \text{ "Red - Level"} \\ 5 & \textit{if} \text{ Tier 1} \\ 3 & \textit{if} \text{ Tier 2} \\ 1 & \textit{if} \text{ Tier 3} \end{cases} \tag{11.5}
$$

11.3.5.2 FLAIM's Overall Fire and Life Safety Index

To determine the platform's overall Fire and Life Safety Index a weighted sum of all risk assessment modules is made to determine the index value. Equation 11.6 is the weighted assessment used to calculate the overall Fire and Life Safety Index. The weighted assessment procedures allows the user to take into account the overall relative importance on any single risk assessment module relative to each other, e.g., how GEFA, LOCA, VESA, LACA, OHFA, RIRA, LISA and SAMSA should be considered on a comparative basis.

$$
GPA_{\text{overall}} = \textit{Overall Fire and Safety Index} = \sum_{j=1}^{5} \sigma_j \, \eta_j \tag{11.6}
$$

where

$$
\sum_{j=1}^{5} \sigma_j = 1.
$$

FLAIM calculates the overall Fire and Life Safety Index using risk equal weighting among all assessment modules. This is in recognition of the need to assess each module's relative weighting value based on the particular platform under consideration; not because of any implied level of equivalency. For example, on newer platforms the risk of LOC events due to mechanical failure may be judged to be relatively low, while the likelihood of a human error caused accident may be high due to simultaneous drilling, production, and construction activities. In this regard, it is important for the user to seek to establish a uniform application of weighting values among groups of similar platforms in order to derive meaningful results from this procedure. It is suggested that operators can meet this objective by establishing their own application criteria that will ensure consistency and uniformity in the application of FLAIM (refer to Chapter 13, Conclusions and Recommendations).

11.4 *ILLUSTRATION OF FLAIM ALGORITHM*

It is important that the user understand how the FLAIM algorithm is functionally arranged in order to facilitate future modifications and customizing as may be appropriate for the intended application. Each question within any given assessment module question worksheet (e.g., LOCA Factors, etc.) is assigned a numeric code. This code is used to identify the type of question being asked which, in turn, determines how the question is handled by the algorithm. **Table 11-4** lists the question code keys used by FLAIM.

Table 11-4
FLAIM Question Code Key

Code	Description
1	denotes a single numeric question where a larger value is good
2	denotes a multiple numeric question where larger values are good
3	denotes a single yes/no question where yes is considered good
4	denotes a multiple yes/no question where yes is considered good
5	denotes a single question with multiple choice answers (A, B, C, D, F)
6	denotes a multiple question with multiple choice answers as above (5)
7	denotes a single yes/no question where no is considered good
8	denotes a multiple yes/no question where no is considered good
9	denotes a single numeric question where a smaller value is good
10	denotes a miltiple numeric question where smaller values are good

The code keys (cell types) are normally out of view of the user when the question worksheet is being displayed; however, by scrolling to the right, the user will note that the next column to appear on the monitor screen contains the appropriate key code for each question. It should be understood that in the event the user desires to modify a question in such a way so as to change the basic form of the inquiry, e.g., such as changing a yes/no question to one requiring a numeric value input, it is necessary to change the key code accordingly.

To illustrate how FLAIM's algorithm operates, consider the following questions:

Table 11-5

Sample Questions

1	What is the capacity of the Living Quarters LQ :	
*	Is the LQ equipped with an automatic smoke detection and alarm system? Y/N	
1	Is the LQ fabricated from noncombustible materials? Y/N	
1	The number of levels of the LQ:	
2	Time rating of LQ exterior walls in accordance w/ recognized fire test -- ASTM E-119 IMO or UL1709: hrs	
2	Are vertical openings between floors, e.g., stairwells, service chases, etc., enclosed by fire rated construction and equipped w/ self closing fire doors? All: A, Most: B, Some: C, Few: D, None: F	

The column to the left of each question indicates the assigned Tier level value selected by a hypothetical users group during the initial FLAIM worksheet setup session. Note that the second question is marked with an "*" indicating that it has been given the status of a red-level question. For the purposes of illustration, assume that the users group determined that for the platform under review, the second question was more important or of more immediate concern than Tier 1 level questions by a factor of two, and that the last two questions were of a level of detail suitable for a Tier 2 review. Consequently the user group assigned this red-level question a weighting value of 10, or twice that of a Tier 1 level question, and retained the FLAIM default value for Tier 1 and 2 level questions. Thus, the weighting values initially assigned to each question were as shown in **Table 11-6** below.

Note the form of each question. The first question is a single numeric input question where a smaller value answer is considered good, e.g., code key (cell type) "9" question since a lower capacity living quarters presents an inherently lower overall risk to life safety. This type of question requires the user to establish a relative value range; for this example, it was the user group's consensus that platforms with living quarters having ten or less bunks should be rated as Excellent (A); those with between ten and twenty bunks should be considered Good (B), and those with between twenty to thirty bunks were considered Fair (C). Platforms with more than thirty bunks were considered Poor (D) with regards to inherent life safety risk, and those with more than fifty bunks were rated as Bad (F).

Table 11-6

Sample Questions Illustrating Weighting Values

Wt.	Question
5	What is the capacity of the Living Quarters LQ :
10	Is the LQ equipped with an automatic smoke detection and alarm system? Y/N
5	Is the LQ fabricated from noncombustible materials? Y/N
3	The number of levels of the LQ:
3	Time rating of LQ exterior walls in accordance w/ recognized fire test -- ASTM E-119 IMO or UL1709: hrs
3	Are vertical openings between floors, e.g., stairwells, service chases, etc., enclosed by fire rated construction and equipped w/ self closing fire doors? All: A, Most: B, Some: C, Few: D, None: F

For this illustration, the subject platform had twenty five bunks which was directly entered as an input to the algorithm. Therefore, when the risk index is calculated for the assessment module (LISA in this example), FLAIM's algorithm reads the question code key to determine how to discritize the input within the assigned range values. Since in this case a smaller value is better, FLAIM determines that a value of twenty five is not better than twenty (the specified range value for Good (B)) and selects a value of 2 or (C) for the question grade. Next, as shown in **Table 11-7**, FLAIM multiplies the grade by the question weight to arrive at a numerical equivalent score for the answered question -- which in this case is ten.

The next question, as already discussed, is considered particularly important to the assessors. It is a single binary question in which an affirmative input is considered favorable; the appropriate code key value assigned is "3." This tells FLAIM's algorithm to multiple the weighted value of this question by a grade value of four, yielding a numerical equivalent score of 20 as shown in **Table 11-7**

Table 11-7

Sample Questions Illustrating FLAIM Algorithm

TIER	QUESTIONS	grade/ value	cell type	cell rng	wt	num equiv	wt* num equiv	N_1	N_2	N_3	N_4	N_5
1	What is the capacity of the Living Quarters LQ:	25	9	0	5	2.0	10.0	10	20	30	50	51
*	Is the LQ equipped with an automatic smoke detection and alarm system? Y/N	Y	3	0	10	4.0	40.0					
1	Is the LQ fabricated from noncombustible materials? Y/N	Y	3	0	5	4.0	20.0					
1	The number of levels of the LQ:	2	9	0	5	3.0	15.0	1	2	3	4	5
2	Time rating of LQ exterior walls in accordance w/ recognized fire test -- ASTM E-119 IMO or UL1709: hrs	0	1	0	3	0.0	0.0	4	3	2	1	0
2	Are vertical openings between floors, e.g., stairwells, service chases, etc., enclosed by fire rated construction and equipped w/ self closing fire doors? All: A, Most: B, Some: C, Few: D, None: F	B	5	0	3	3.0	9.0					

The overall assessment grade is calculated by taking the quotient between the sum product of the weights (**wts**) and numerical equivalence (**num equiv**) and the sum of the weights. For the following example above, the grade assessement of 3.03 (approximately a "B" average) is equated.

$$\eta_j = \frac{\sum_i^n \omega_{ij}\eta_{ij}}{\sum_i^n \omega_{ij}}$$

$$= \frac{5*2.0+10*4.0+5*4.0+5*3.0+3*0.0+3*3.0}{5+10+5+5+3+3}$$

$$= 3.03$$

Each of the subsequent questions are answered accordingly to generate a numerical equivalent score. As already discussed, single binary questions are graded either as 4 points or 0 points. The algorithm process for the sample questions yields a total numerical equivalent score of 3.03 or, in terms of an overall letter grade, a solid "B."

---

[1] FLAIM was designed in contemplation of a review group performing the initial worksheet calibration process, much as a HazOp is performed by a selected group of experienced personnel representing engineering, operations, maintenance and inspection, safety, etc. In this manner, both the rangevalues and weights of critical questions may be determined as deemed appropriated for the specific region of operations and platform design factors.

[2] The basic difference between red-level and Tier 1 questions is that the former are considered to be questions which are generally important to the operations of all offshore structures, whereas Tier 1 level questions may be specific to the platform being analyzed

[3] x^t_{ij}: pre-defined range value for question i, assessment j, and range value t

[4] y^t_{ijk}: pre-defined range value for question i, assessment j, sub-question k and range value t

Chapter 12

MANAGING RISK USING FLAIM

Using FLAIM's risk factors as meaningful risk management tools depends to a large extent on how the user ultimately "calibrates the risk meter." Chapter twelve discusses the application of FLAIM's outputs and describes how users can best apply them for improving platform safety. Understanding that, much like more complicated quantified risk assessment techniques, the main benefit to be derived is a relative understanding of risk on a comparative basis. Chapter 12 encourages the user to consider FLAIM as a basis from which to build and mold in accordance with the experience and service demands of the platforms under consideration. In addition a procedure for performing cost-benefit analysis to evaluate fire and life safety risk management alternatives has been developed. The procedure incorporates the risk index methodology with decision making analysis techniques to provide the user with an effective decision support tool to optimize topside safety as illustrated in § 12.4.

12.1 *CALIBRATION AND APPLICATION OF RISK INDEX*

Bea[1] has described three basic approaches that can be used to develop insights for decision analysis concerning issues of risk and reliability for coastal and offshore structures. They are the historical-calibration approach which relies on the past experience of similar platforms operating under similar conditions; the code-calibration approach, such as developed by Nelson and Shibe[2] to determine the code-equivalency of performance-based designs to meet minimum life safety prescriptions; and the cost-utility approach (using a multiattribute utility function) which relies on assessing total cost, including the cost of failure or "risk cost" associated with various attributes, in order to identify the most attractive choice, e.g., the choice of highest utility, with deference to management's persuasion toward risk aversion.

FLAIM's quasi-quantitative-qualitative derived risk indices allows the user a choice of decision making approaches. Correlation of risk indices to potential platform consequence levels and likelihood can be accomplished by calibrating FLAIM using available historical databases in order to access acceptable levels of risks and appropriate risk reduction measures. However, as Jasanoff has eloquently expressed, there is room for a more radically integrated approach to thinking about risk analysis then the dominate decision-making model fostered by the National Research Council's "Red Book."[3] As

Campbell opines, "the real object of RA (risk assessment) is risk management, not just assessment of risk....the aim is to manage all risks through allocation of resources to various competing demands such that profitability is maximized...until this objective is demonstrated in practice, discussions of RA's contribution to offshore design methodology is a red herring."[4]

The petroleum and petrochemical industries[5] have traditionally relied primarily on an experienced-based historical approach to make risk management decisions. This practice has started to change recently with the growing use of predictive hazard analysis techniques fostered by federal[6] and state legislation, Gretener[7] believed that determining fire risk by statistical methods alone had several shortcomings, including reliance on inadequate analysis of causal factors impacting the severity of the loss and thereby distorting the statistical data, and failure to consider the effect of technological advances that can invalidate past experience. Statistical records may also fail to reflect the operator's perception of risk and how this influences decisions in the organization.[8]

Such concerns led Gretener to develop a risk-indexing approach using empirically derived numerical values to characterize fire risk and fire protection measures. He found that the relative fire hazard of a facility could be characterized by dividing the potential hazard factors by protective measure factors, where the potential hazard factors account for the probability that a fire will start and its likely severity.[9]

In the context of risk management decision analysis, FLAIM may be used as a measure of a platform's expected disutility[10] resulting from fire and life safety risks as they are characterized by the derived risk contributing factors described herein. As explained throughout this dissertation, FLAIM purposefully encompasses both intrinsic and extrinsic aspects of platform operations, and consequently, its risk indices may be directly used to determine the minimum value of expected disutility, reflecting both physical and cultural (risk aversion) aspects of safe operations.

A multiattribute disutility function is appropriate for comparing risk attributes in terms of the cost of fire (including physical damage and business interruption/deferred production), loss of life, and environmental damage. Both the individual disutility functions [$u_i(x_i)$] and scaling constants (k_i) can be assessed directly from FLAIM's algorithm as derived from the responses to key questions addressing or otherwise indicative of various levels of risk aversion for each attribute. According to Bea,[11] the identified attributes may be considered reasonably representative of preferential independence conditions, and one of two model forms can be used to assess utility, or in this case disutility.

The multiplicative multiattribute disutility model takes the form:

$$1 + ku(x_1, x_2, x_3) = \prod_{i=1}^{3} 1 + kk_i u_i(x_i) \tag{12.1}$$

and the additive multiattribute disutility model takes the form:

$$u(x_1, x_2, x_3) = \sum_{i=1}^{3} k_i u_i(x_i) \tag{12.2}$$

where $u(x_1, x_2, x_3)$ = multiattribute disutility, $u_i(x_i)$ = value of the i^{th} attribute, k_i = individual disutility for the i^{th} attribute, and k_i = a scaling constant expressing tradeoffs between attributes, and k = a normalizing constant

If $\sum k_i \neq 1$, then equation (12.1) is used, whereas if $\sum k_i = 1$, then equation (12.2) is appropriate.

The shape of the utility function depends on the preferences of the decision makers. An unbiased risk-neutral utility function is linear whereas a risk averse or risk prone utility function is nonlinear as illustrated in **Figure 12-1**.

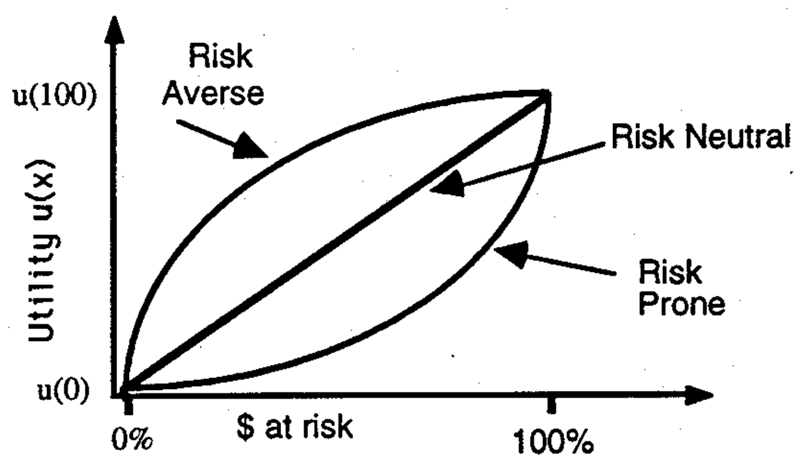

Figure 12-1
Risk Effects on Form of Utility Function

Risk preferences may change however depending on the severity of the consequences and the perception of the relative degree of risk as perceived by management. For example, Ramachandan[12] suggests a Sigmoid utility function to describe risk prone decision preferences for low consequence events and risk averse decision preferences for large consequence events.

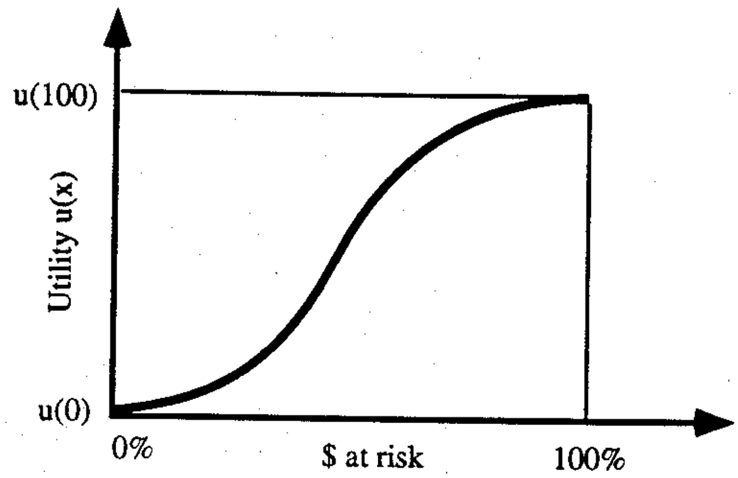

Figure 12-2
Effect of Variable Risk Attitude as a Function of Consequence

This type of utility function (**Figure 12-2**) would be appropriate for use by platform operators who may be willing to budget greater funds and resources for controlling high consequence -- low frequency events as opposed to low-consequence -- high frequency events (nuisance events), even if the absolute risk[13] of either kind of event is identical. The influence of risk aversion to large losses may in fact at times seemingly result in a misapplication of company resources (e.g., poor risk management) in terms of investment, as it is often more cost-effective to reduce high frequency events, which are generally directly responsive to management controls, than to try to control rare events that have a large degree of uncertainty[14] and which may require the expenditure of large sums of money to attempt to mitigate, e.g., have highly uncertain cost-benefit ratios.

Ramachandran[15], et al., have observed that the probability distribution of losses caused by fire is skewed and may be generally represented as a log-normal distribution. If a log-normal probability distribution is used as representative of platform disutility, the normal loss expectancy (NLE) for the platform may be calculated as:

$$\bar{x} = e^{\left(\mu + \frac{\sigma^2}{2}\right)} \tag{12.3}$$

where σ is the standard deviation and μ is the mean of $z = \ln x$

For risk averse decision makers, Ramachandran suggests the following disutility function:

$$D(x) = e^{\theta x} \tag{12.4}$$

for $\theta > 0$ where θ is a measure of risk aversion ($\theta = 1$ for risk neutral or indifferent decisions) based on the value of the asset and the concern over consequences, and x is the fire loss

The benefit of a risk reduction measure may be expressed in terms of reduction of the NLE for any given platform or group of similar platforms operating under similar conditions. For risk-neutral decisions, this amounts to a straight forward cost-benefit analysis, assuming the decrease in the NLE can be reasonably quantified for each proposed risk reduction measure; which obviously is highly problematic. Consideration of the relevant factors affecting fire loss and their interaction is really the crux of the problem. One approach developed by Ramachandran[16] uses a multiple regression model based on extreme order theory and assigned numerical values to factors judged to affect the severity of damage. Similarly, platform operators may chose to calibrate FLAIM's risk indices using proprietary fire loss databases so as to develop a direct correlation to cost-benefit decisions within the framework of the decision maker's own risk preferences, while also accounting for highly variable localized conditions and associated regional variations in human factors as noted by Jansnoff.

12.2 *SCREENING PLATFORM RISK FACTORS*

FLAIM has been designed to accommodate the user in two ways. First, it allows the user to examine platform fire and life safety issues in increasingly higher degrees of analysis (see **Figure 12-3**). The screening procedure described below follows the same general procedure established for structural requalification of offshore platforms proposed by Williamson and Bea (1992).[17] Tier 1 is the initial screening procedure designed to assess the general state of platform risk with regard to both level of consequence and the likelihood of incident occurrence. Tier 1 consists of sets of questions that are considered to be basic but, at the same time, the most important questions relevant to overall platform operations and potential for loss. Depending of the results of initial screening, a Tier 2 or Tier 3 screening may be warranted for any given assessment under consideration.

Tiers 2 and 3 consists of supplemental questions intended to further delineate the state of operations and the relative risk-state of the platform. Tier 2 and 3 questions have been weighted at correspondingly lower values than those of Tier 1, and are increasingly more comprehensive and detailed. Consequently, as FLAIM is applied in higher screening levels, a more detailed level of understanding and assessment of platform risk is derived.

Throughout the process, the user performs two vital roles. First, the user checks and verifies the applicability of questions identified for each screening level in accordance with user preferences and experiences, e.g., FLAIM is interactive in both its content and in its application. Second, input to FLAIM is intended to represent a consensus of opinion, derived from a collective response from those individuals most familiar with the design and operation of the platform and its present exposure to loss. In this sense, FLAIM draws on industry's present familiarity with the HazOp procedure, e.g., Hazard and Operability Study, to ensure validity of response input, but without the cumbersome technical analysis procedures demanded by HazOp.

Questions have been developed reflecting offshore fire and life safety experiences, and professional expertise, case histories, API RP's, regulatory requirements, and other relevant sources. Default weightings for the questions have been assigned without regard to regional factors or unique considerations that may significantly influence the evaluation. In recognition of this, FLAIM has been specifically developed for the users to modify the weighting values and suggested tier level in order to account for unique design operating conditions.

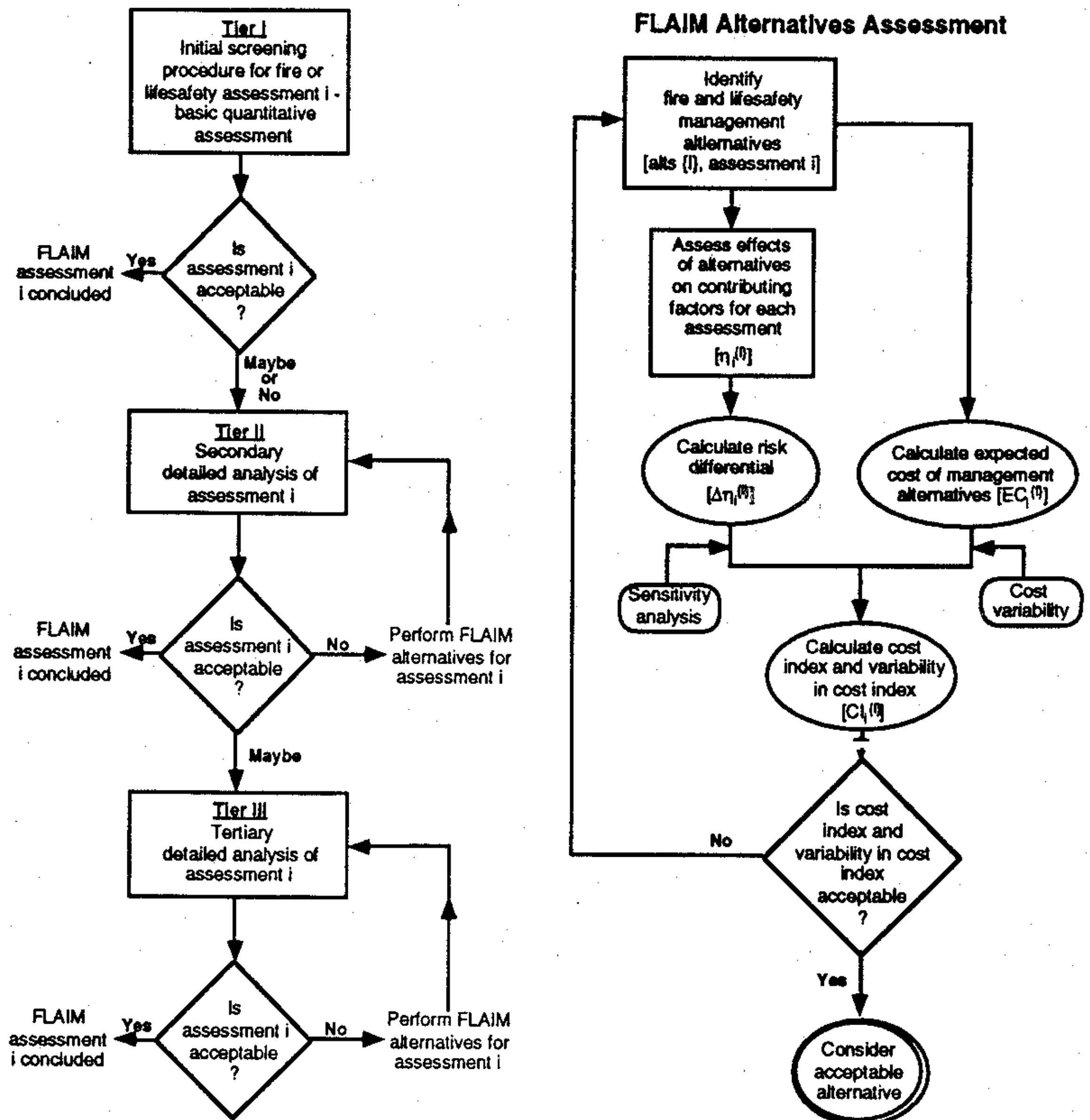

Figure 12-3

FLAIM Screening Procedure

12.2.1 FLAIM Screening Process

Tier 1 analysis primarily seeks to establish the design, operating factors, and level of potential consequences. The function of the Tier 1 analysis is to determine the platform consequence levels and potential exposure to loss. The most critical factors are identified by the user and assessments are made as to the state of the system. The Tier 1 assessment is a screening procedure used to determine if a Tier 2 or eventually Tier 3 analysis is necessary (see **Figure 12-3**). If the Tier 1 assessment is acceptable (Yes), the assessment is concluded, if the assessment is unacceptable or uncertain (Maybe or No), a Tier 2 screening procedure is necessary. Note that a unique feature of FLAIM allows for the user to decide the appropriate tier level for implementation for any given assessment being performed (e.g. LOCA, VESA, etc.). This allows those areas deemed to be of greatest concern to be more fully explored on an as needed basis.

The Tier 2 and Tier 3 screening procedures are used to describe detailed information of particular fire and life safety factors. Uncertainty and non-consensus between users as to the state of the system leads to a more detailed analysis. If a Tier 2 analysis is acceptable, then the assessment is concluded. If it is not acceptable, fire and life safety management alternatives are identified, their effects upon the system assessed, and considered for implementation (see Section 12.3). Another assessment is performed to determine if a Tier 3 analysis is needed to assess the direct and indirect effects of the alternatives upon the operating system.

If a Tier 2 assessment is insufficient to capture the important contributing fire and life safety factors, then a Tier 3 assessment is performed. The purpose of a Tier 3 analysis is to capture the exceptionally detailed factors related to an fire and life safety analysis. If the Tier 3 is accepted, the assessment is concluded. If the assessment is not accepted, fire mitigation and prevention procedures are evaluated. Acceptable alternatives are identified, their effects upon the system assessed, and considered for implementation (see Section 12.3). The chosen alternatives are assessed in a Tier 3 analysis and determined if acceptable.

12.3 *FLAIM's RISK MANAGEMENT ALTERNATIVES COST-BENEFIT MODEL (ACBM) PROCEDURE*

First, it should be made clear that the purpose of *Alternatives Cost-Benefit Modeling* (ACBM) is to assist offshore operators in (1) identifying possible fire and accident prevention and mitigation procedures, and (2) assessing their cost-benefit (economic and the FLAIM safety index) to the safety of the operating system. The general ACBM procedure is described in **Figure 12-4.**

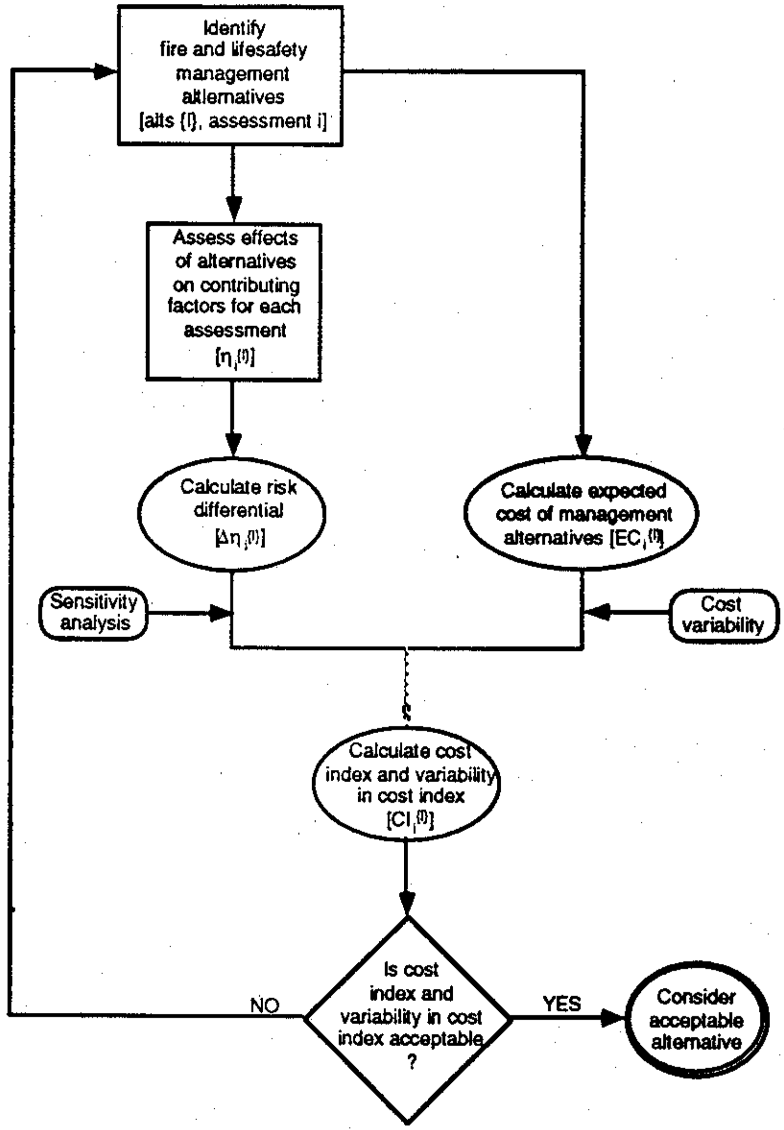

Figure 12-4

<u>**ACBM Procedure for FLAIM**</u>

The framework of the ACBM procedure includes steps to determine whether alternatives are "acceptable". Acceptable would be a decision which is made by the operators, society, regulatory agencies, etc. Section 12.3.1 is a basic explanation of the ACBM procedure (**Figure 12-4**) and how it is used to address fire and life safety management alternatives for FLAIM. Section 12.3.2 is the mathematical description for how the ACBM is integrated into the FLAIM algorithm (mathematical description).

12.3.1 The ACBM Procedure

(1) Identify management alternatives which affect technical, human, or management related change. Once alternatives are identified, they may be consolidated together into different sets constrained by economics, levels of importance, "logic", etc.... For example, installing firewalls (passive fire protection) and a deluge system (active fire protection) may be a set of alternatives to ensure passive and active fire protection.

(2) Assess the effects of a set of management alternatives[18] on fire and life safety factors for each assessment i (LOCA, VESA, LACA, etc.). The effects on each fire and life safety contributing factor may (or may not) have the same relative effect. For example, the installation of firewalls has a direct effect upon the factors in the vulnerability to escalation (VESA) factors, though an indirect effect upon life safety factors with regard to protection (escape or "safe haven"). Therefore, multiple alternatives should be addressed in sets to determine the marginal effect upon that fire or life safety contributing factor.

The fire and life safety assessments should be assessed as a set and not by assessing the marginal effects of each alternative separately, e.g., the effects of each alternative may not necessarily be directly additive. For example, the risk index value of constructing a firewall separating a wellbay from a gas compression module and upgrading the deluge system in the wellbay may be different than just calculating each separately and then adding the effects together (see Section 12.3.2). The impact of one alternative to fire or life safety may have an effect upon the need or reliability of the other.

(3) The next step is to directly calculate the *risk index differential* ($\Delta\eta_i^{\{1\}}$). The risk index differential is the difference between implementing the set of management alternatives and not implementing any management alternatives ($\Delta\eta_i^{\{1\}} = \eta_i^{\{1\}} - \eta_i$).

(4) Uncertainty in the effect of management alternatives on the system is an issue that may warrant further consideration. FLAIM is considered as a screening procedure and as such largely depends upon the accuracy and thoroughness of its users. Uncertainty may be the result of both the effects of management alternatives and in the values selected in the screening process. If

appropriate based on initial feedback, future versions of the FLAIM algorithm can incorporate a sub-routine in its macro that allows the user to account for uncertainties in the modeling procedure using the @ *Risk* program[19] in Excel). Distributions can be then estimated (e.g. log normal, uniform, normal, etc.) to assess the effects of management alternatives on fire and life safety risk factors. Monte Carlo simulations may be performed to arrive at a distribution for each risk index assessment.

(5) The cost of management alternatives is also determined. The cost for implementing management alternatives can be derived by a deterministic cost assessment or by an expected cost estimate. The simplest method would be to use nominal cost estimates for implementing a management program (human and organizational related) or construction - retrofitting (technical change). However, there could be uncertainty involved in the cost estimating (location, unexpected or indirect costs, time, inflation, foreign exchange, etc.).

Historical data can be studied to determine the variability of costs of implementing the management alternatives. This leads to calculating a distribution of costs. A cost standard deviation (or variance) is then calculated ($\sigma_{EC_i}{}^{\{1\}}$).

(6) The next step is to calculate a *cost index* ($CI_i{}^{\{1\}}$) and the standard deviation of the cost index ($\sigma_{CI_i}{}^{\{1\}}$). The cost index is the product of the cost of implementing the management alternatives, the risk index differential, and a *platform consequence factor*. The platform consequence factor is a value used to determine the difference between platforms with regard to the impact of losing the platform. For example, the platform consequence level of a new $2 billion dollar gravity structure in the North Sea with a crew of 300 men would be higher than that of an unmanned 30 year old platform in the GOM. The consequence factor used can be the normal loss expectancy (NLE) or probable maximum loss (PML) for the platform.

The standard deviation (variance) of the cost index can be calculated in any one of a variety of ways, such as by using the @ *Risk* program[20] which performs a Monte Carlo simulation to produce a distribution of values for the cost index ($CI_i{}^{\{1\}}$). This component of FLAIM is for future development.

(7) The next step is to examine the cost index and the variability in the cost index to determine whether the values are acceptable. For example, the mean or median and the standard deviation can be examined to determine acceptability. A large standard deviation may lead to a reevaluation of the alternative or a search for ways to reduce the level of uncertainty (reduce the standard deviation) such as by collecting more information.

(8) If the set of management alternatives is acceptable, the alternatives can be considered as viable options to reduce risks of fire and life safety. After all alternatives of interest have been evaluated, a final choice of alternatives is made. The values arrived at through this cost index are used as a decision support to the management alternative selection process. They should not be used as the only criteria from which alternatives are selected.

12.3.2 ACBM Format For FLAIM's Algorithm

As shown in Equation 12.5 this is the Grade Point Average (GPA) for assessment i (where the assessments are the LOCA, VESA, LACA, etc.).

$$\eta_i = \frac{\omega_{i1}\,\eta_{i1} + \omega_{i2}\,\eta_{i2} + \cdots + \omega_{in}\,\eta_{in}}{\omega_{i1} + \omega_{i2} + \cdots + \omega_{in}} = \frac{\sum_j^n \omega_{ij}\,\eta_{ij}}{\sum_j^n \omega_{ij}} \tag{12.5}$$

Equation 12.6 is the new GPA value for the assessment i with the set of management alternatives {1} ($\eta_i^{\{1\}}$). The *weighing change parameter* ($\alpha_{ij\{1\}}$) is the ratio between of the new weighting value (assessment i, question j) and the prior weighting value ω_{ij} with no management alternatives.[21] The *grading change parameter* ($\gamma_{ij\{1\}}$) is the ratio between of the new grade value (assessment i, question j) and the prior grade value η_{ij} with no management alternatives.[22]

$$\eta_i^{\{l\}} = \frac{\alpha_{i1\{l\}}\,\omega_{i1}\,\gamma_{i1\{l\}}\,\eta_{i1} + \alpha_{i2\{l\}}\,\omega_{i2}\,\gamma_{i2\{l\}}\,\eta_{i2} + \cdots + \alpha_{in\{l\}}\,\omega_{in}\,\gamma_{in\{l\}}\,\eta_{in}}{\alpha_{i1\{l\}}\,\omega_{i1} + \alpha_{i2\{l\}}\,\omega_{i2} + \cdots + \alpha_{in\{l\}}\,\omega_{in}} \tag{12.6}$$

$$= \frac{\sum_{j}^{n} \alpha_{ij\{l\}}\, \omega_{ij}\, \gamma_{ij\{l\}}\, \eta_{ij}}{\sum_{j}^{n} \alpha_{in\{l\}}\, \omega_{in}}$$

The risk index differential ($\Delta\eta_i^{\{l\}}$) is the difference in GPA's between implementing the set of alternatives {l} and not implementing any management alternatives (Equation 12.7).

$$\Delta\eta_i^{\{l\}} = \eta_i^{\{l\}} - \eta_i = \frac{\sum_{j}^{n} (\alpha_{ij\{l\}}\, \omega_{ij}\, \gamma_{ij\{l\}}\, \eta_{ij} - \omega_{ij}\, \eta_{ij})}{\sum_{j}^{n} (\alpha_{in\{l\}}\, \omega_{in} - \omega_{ij})} = \frac{\sum_{j}^{n} (\alpha_{ij\{l\}}\, \gamma_{ij\{l\}} - 1)\omega_{ij}\, \eta_{ij}}{\sum_{j}^{n} (\alpha_{in\{l\}} - 1)\omega_{ij}} \quad (12.7)$$

As described above (Section 12.3.1) the impacts upon fire and life safety risk assessments of the set of management alternatives {l} can be different than if each assessment was measured marginally and summing over each alternative l. As described in Equations 12.8 and 12.9, the weighing and grading change parameters have a minimum constraint by having no effect upon assessment i, question j ($\alpha_{ij\{l\}} = \gamma_{ij\{l\}} = 1$). On the other hand, the maximum parameter values would be realized if each alternative l was assessed separately and summed over the entire set.

$$1 \le \alpha_{ij\{l\}} \le \sum_{l}^{m} \alpha_{ijl} \quad (12.8)$$

$$1 \le \gamma_{ij\{l\}} \le \sum_{l}^{m} \gamma_{ijl} \quad (12.9)$$

To calculate the cost index ($CI_i^{\{l\}}$) for assessment i, alternatives {l}, the cost of implementing management alternatives {l} ($EC^{\{l\}}$) is divided by the product of the*consequence factor*[23] κ_h and the risk differential ($\Delta\eta_i^{\{l\}}$), and as shown in Eqn. 12.10.

$$CI_i^{\{l\}} = \frac{EC^{\{l\}}}{\kappa_\eta \Delta\eta_i^{\{l\}}} \quad (12.10)$$

The standard deviation (variance) in the cost index ($CI_i^{\{l\}}$), is shown in Equation 12.11. This would be the product of the consequence level, and variances of the risk differential and cost.

$$
\begin{aligned}
\sigma_{CI_i^{(j)}} &= \sqrt{\sigma^2_{CI_i^{(j)}}} \\
&= \sqrt{\kappa_h^2 \sigma^2_{\Delta\eta_i^{(j)}} \sigma^2_{EC_i^{(j)}}} \\
&= \kappa_h \ \sigma_{\Delta\eta_i^{(j)}} \ \sigma_{EC_i^{(j)}}
\end{aligned} \tag{12.11}
$$

12.4 *ILLUSTRATION OF FLAIM ACBM PROCEDURE*

To illustrate the ACBM procedure, consider the following example. A leaseholder recently completed a FLAIM Tier 1 screening assessment of several older production platforms and identified one high consequence[24] platform on which the overall topside risk index was deemed to be sufficiently low so as to warrant further review. After performing a Tier 2 assessment, several potential problems were identified in greater detail together with possible approaches for mitigating topside fire and life safety risks.

In order to extend the operating life of topsides production systems and achieve an acceptable level of risk, (e.g., a minimum risk index of 2.5) management deemed that it would be necessary to 1) provide structural fireproofing for all main support members throughout the open deck process areas, or alternatively 2) provide a fixed water spray system in order to provide exposure protection to structural steel supports as well as the process equipment. This second alternative required upgrading of the existing platform fire pumps. As a third alternative, managment wished to evaluate if there was sufficient justification for implementing both alternatives under consideration.

To decide which alternative was most cost effective, the previously run FLAIM assessment was modified to determine the risk index for each alternative was well as the corresponding risk differential. In this case, based on the weighting values assigned by the reviewers, it was determined that providing fireproofing yielded a risk differential +0.82. This was due in part to recognition of the inherently higher reliability and greater endurance of a passive fire protection system over that of an active system.

The initial capital cost of providing fireproofing was estimated to be $300,000, and the average annual operating and maintenance costs, e.g., lifecycle costs, were determined to be about $5000/ year. Similarly, the capital costs for a new water spray system was estimated at $200,000 with an average annual operating and maintenance cost of $25,000. The expected life-extension of the platform was based on continued operations for another ten years, and the maximum probable loss (MPL) based on insurance underwriters' surverys was estimated to be $15,000,000.

12.4.1 *Application of the ACBM Procedure*

The first step in the procedure is to calculate the net present worth or value (NPV) of the cost for each alternative as well as their combined sum.[25]

Alternative 1: Fireproofing ($300,000 + $5000/yr.)
Alternative 2: Water Spray ($200,000 + $25,000/yr.)
Alternative 3: Fireproofing and Water Spray ($500,000 + $30,000/yr.)

Expected cost of alternative 1 (NVP @ 6% discount rate): EC_1 = **$336,800.43**
Expected cost of alternative 2 (NVP @ 6% discount rate): EC_2 = **$384,002.17**
Expected cost of alternative 3 (NVP @ 6% discount rate): $EC_3 = EC_1 + EC_2$
EC_3 = **$720,802.60**

Alternative 1 risk index diferential: $\Delta\eta_i^1 = \eta_i^1 - \eta_i = +0.82$

Alternative 2 risk index diferential: $\Delta\eta_i^2 = \eta_i^2 - \eta_i = +0.38$

Alternative 3 risk index diferential: $\Delta\eta_i^3 = \eta_i^{(1,2)} - \eta_i = +1.07$ [26]

The Consequence Factor (K):

The consequence factor is normally used only when the choice of alternatives involves more than one platform, each having differing consequence levels. In this example, management elected to utilize the Normal Loss Expectancy that was previously estimated by insurance underwriters at $1,000,000.00.

Calculating the Cost Index Using Equation 12.10:

$$CI_i^{(l)} = \frac{EC^{(l)}}{\kappa_\eta \Delta\eta_i^{(l)}}$$

$$CI_i^1 = \frac{(336,800.43)}{(1,000,000)(0.82)} = 0.41$$

$$CI_i^2 = \frac{(384002.17)}{(1,000,000)(0.38)} = 1.01$$

$$CI_i^3 = \frac{(720,802.60)}{(1,000,000)(1.07)} = 0.67$$

In this example, management felt sufficiently confident in the alternative cost estimates based on past experience to forego an uncertainty analysis to determine the expected cost distribution and variance. Based on this analysis, management concluded that alternative 1 (fireproofing) was clearly the most cost effective risk reduction measure to implement -- more that two and one half times as effective as installing a water spray system. Moreover, it was unexpectedly realized that a combination of both water spray and fireproofing was significantly more effective from a risk-cost management prespective than installing a water spray system by itself.

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[1] Bea, R.G., *Reliability Based Design Criteria For Coastal And Ocean Structures*, Design Criteria for Marine Structures, NA 290C, Department of Naval Architecture and Offshore Engineering, University of California, Berkeley, 1990, p. 062 of course syllabus

[2] Nelson, H. and Shibe, A, *A System for Fire Safety Evaluation of Health Care Facilities*, NBSIR 78-1555, Center for Fire Research, National Bureau of Standards, November, 1978 pp. 1-45

[3] According to Jasanoff, 1983 NRC's Red Book (*Risk Assessment in the Federal Government, Managing the Process*), which still largely dominates the thinking of risk analysis experts today, calls for a stringent separation between the risk assessment based on quantified risk assessment principles and "the value-laden process of risk management." Jasanoff suggests that qualitative studies that focus on ethical, legal, political, and cultural aspects of risk exist conceptually on a single continuum with quantitative, model-and-measure-oriented analyses of risk. She explains that each approach is needed to comprehensively treat the nature and extent of risk in a technological society. For example, Jansnoff points out that pictures we construct of risk are always under inclusive, e.g., key elements will be left out of consideration if the scale of the analysis is too small or too large. Risk assessment models tend to be extraordinarily compact; constraining assumptions that are built into procedures for assessing risk are recurrent, and can cause quantitative risk scenarios to be unduly biased, vis-a-via the oil fires in Kuwait did not in fact lead to a localized "Nuclear Winter" as some modelers had warned. Jansnoff points out that failure to account for highly variable, localized environmental conditions and associated variations in human behavior have been the frequent cause of inaccurate predictions. For example, she uses the Bhopal catastrophe to illustrate a technological example of material thing s interacting with people and institutions to produce consequences that no one had thought to predict, and argues that the "culture" of qualitative risk analysis offers at least a partial antidote to such surprises, because it provides a relatively systematic approach to thinking about the constraining assumptions and pitfalls of approaches that are based solely on regimented quantified "scientific" methodologies [ref. Jasanoff, S., *Bridging the Two Cultures of Risk Analysis*, Risk Analysis, Vol. 13, No. 2, April, 1993, pp. 123-129

[4] Campbell, J.M., *Review of Applications and Limitations or Risk Assessment in Offshore Exploration and Production for AMOCO Production Company*, John M. Campbell & Company, Norman, OK, November 29, 1984, p. 5

[5] A notable exception is the Dow Fire and Explosion Index methodology. See § 2.3

[6] e.g., U.S. Code of Federal Regulations, 29CFR1910.119 re: Process Safety Management

[7] see § 2.2.4

[8] Decision analysis depends on two aspects of risk: (1) possible consequences associated with alternative choices and their associated likelihoods, and (2) the decision maker's preferences for the consequences [see, Bea, R.G., *Decision Analysis Approach to Offshore Platform Design*, Design Criteria for Marine Structures, NA 290C, Department of Naval Architecture and Offshore Engineering, University of California, Berkeley, 1990, p. 231 of course syllabus]. For example, Arendt, et al. performed a hazard analysis and risk assessment of a large petroleum refinery in order to examine ecomomic risk due to loss of containment events. A preliminary hazards analysis (PHA) was performed to identify important risk contributors associated with loss of containment, and a risk based analysis was performed on those items identified in the PHA. A detailed assessment of the expected frequencies and consequences of potential accidents was made to assess "absolute risk" levels. However, to account for the level of concern that the operator had for some types of accidents (consequences), the "concern risk" (preceived risk) was also estimated. In this example, it was found that refinery unit compressors accounted for approximately 36% of the absoulute risk, but 54% of the concern risk; conversely, fired heaters accounted for 17% of the absolute risk, but 25% of the concern risk. See Arendt, J.S., et al., *Improving Refinery Availability Through Ecomomic Risk Assessment*, JBF Associates, Inc. Knoxville, TN., presented at the API Committee on Safety and Fire Protection Spring Meeting (Paper # 28), April, 1985; also see by the same authors *A Risk-Based Analysis of a Petroleum Refinery* (Part 1 of 2 parts), Hazard/Prevention, January/February, 1985; and *Preliminary hazards analysis conducted on FCCU complex*, Oil & Gas Journal, August 8, 1988, pp 60-66

[9] Watts, J., Fire Risk Assessment Schedules, The SFPE Handbook of Fire Protection Engineering, Society of Fire Protection Engineers, National Fire Protection Association, Quincy, MA. 1988, p. 4-91

[10] *Disutility* is used herein in the negative context of *Utility* in the analysis of decisions involving negative outcomes such as fire loss or the cost of fire protection. See Ramachandran, G., *Utility Theory*, The SFPE Handbook of Fire Protection Engineering, Society of Fire Protection Engineers, National Fire Protection Association, Quincy, MA. 1988, p. 4-64 -- 4-73

[11] Bea, R.G., *Decision Analysis Approach to Offshore Platform Design*, Design Criteria for Marine Structures, NA 290C, Department of Naval Architecture and Offshore Engineering, University of California, Berkeley, 1990, p. 239 of course syllabus]

[12] Ramachandran, G., *Extreme Value Theory*, The SFPE Handbook of Fire Protection Engineering, Society of Fire Protection Engineers, National Fire Protection Association, Quincy, MA. 1988, pp. 4-28 -- 4-29 and p. 4-67

[13] Absolute risk, R_a, is used here to denote the product of probability of failure, P_f, and severity of consequence, C_s

[14] e.g., those events falling in the tails of ill-defined probability distribution functions. For example, the absolute annual risk of one crew member being killed every year for a period of 100 years is the same as that in which a single event kills 100 people each 100 years; however, the impact of the latter is generally of much greater concern to management, irrespective of cost issues.

[15] Ramachandran, G., *Extreme Value Theory*, op. cit.

[16] Ibid., pp. 4-30 -- 4-31

[17] Williamson, R.B. & Bea, R.G. (1992) *Firesafety Assessment for Existing Offshore Platforms*. Proposal: College of Engineering, University of California at Berkeley. UCB Eng - 8330.

[18] The set of management alternatives l are represented by the superscript "{l}". A single management alternative is represented by "l".

[19] The feature is planned for future versions of FLAIM

[20] The feature is planned for future versions of FLAIM

[21] $\alpha_{ij\{1\}} = \dfrac{\text{new weight value for management alternatives \{1\}}}{\omega_{ij}}$

[22] $\gamma_{ij\{1\}} = \dfrac{\text{new grade value for management alternatives \{1\}}}{\eta_{ij}}$

[23] κ_h = Consequence factor for platform h.

[24] Based on a Probable Maximum Loss (PML) extimate exceeding ten million dollars as determined by management

[25] For the sake of illustration, it is assumed that total cost of implementing both alternatives is the sum of their indivudual NPV; however, in actual practice, the total cost of implementing both alternatives would be expected to be higher due to constructability factors and time delays incurred in a combined project.

[26] Notice that the risk index differential for implementing both alternatives together, i.e., $\Delta\eta_i^3$, does not equal the sum of each individual alternatives differential risk index when implemented exclusive of each other.

Chapter Thirteen

CONCLUSIONS AND RECOMMENDATIONS

The focus of this work has been safety management on offshore hydrocarbon production platforms. The fundamental objective was to arrive at a practical and effective procedure for assessing and managing fire and life safety risks onboard existing offshore oil and gas production platforms located on the U.S. Outer Continental Shelf (OCS). Successful implementation of FLAIM, as does the safe operation of offshore production platforms, largely depends on the skill and knowledge of people effecting it, e.g., human and organizational factors. FLAIM has been designed to serve as a risk assessment and management tool to be used by informed people; if applied with forethought and consistency, it should prove to be a valuable aid in the decision making process.

The cause and consequence of fires and explosions on offshore production platforms are extremely complex and highly dependent events that may have only indirectly related precedents. Lack of comprehensive and meaningful statistical data and models on offshore system failures, human error, organizational factors, consequence analysis, etc. create a large uncertainty inherent in applying any predictive hazard analysis technique to a production platform. FLAIM has drawn on many resources in an effort to combine deterministic and heuristic considerations into a unified approach for managing offshore fire and life safety risk. While FLAIM may be particularly helpful in identifying important considerations heretofore overlooked in the risk assessment process, it ultimately relies on the subjective probability and judgment of its users' input to assess relative states of risk.

Although the legitimacy of subjective probability[1] has come to be widely accepted, as has the use of indexing methodologies as discussed in Chapter Two, care is needed in the process of quantifying expert opinion and group consensus. Several techniques have been developed, such as the widely known Delphi technique[2] developed by researchers at the RAND corporation, which strives to avoid problems associated with group interactions such as personality conflicts and peer pressure that may introduce a bias in the collective response.

It has been observed[3] that objective probability, based on statistical data, is believed by everyone except by the statistician; whereas subjective probability, based on

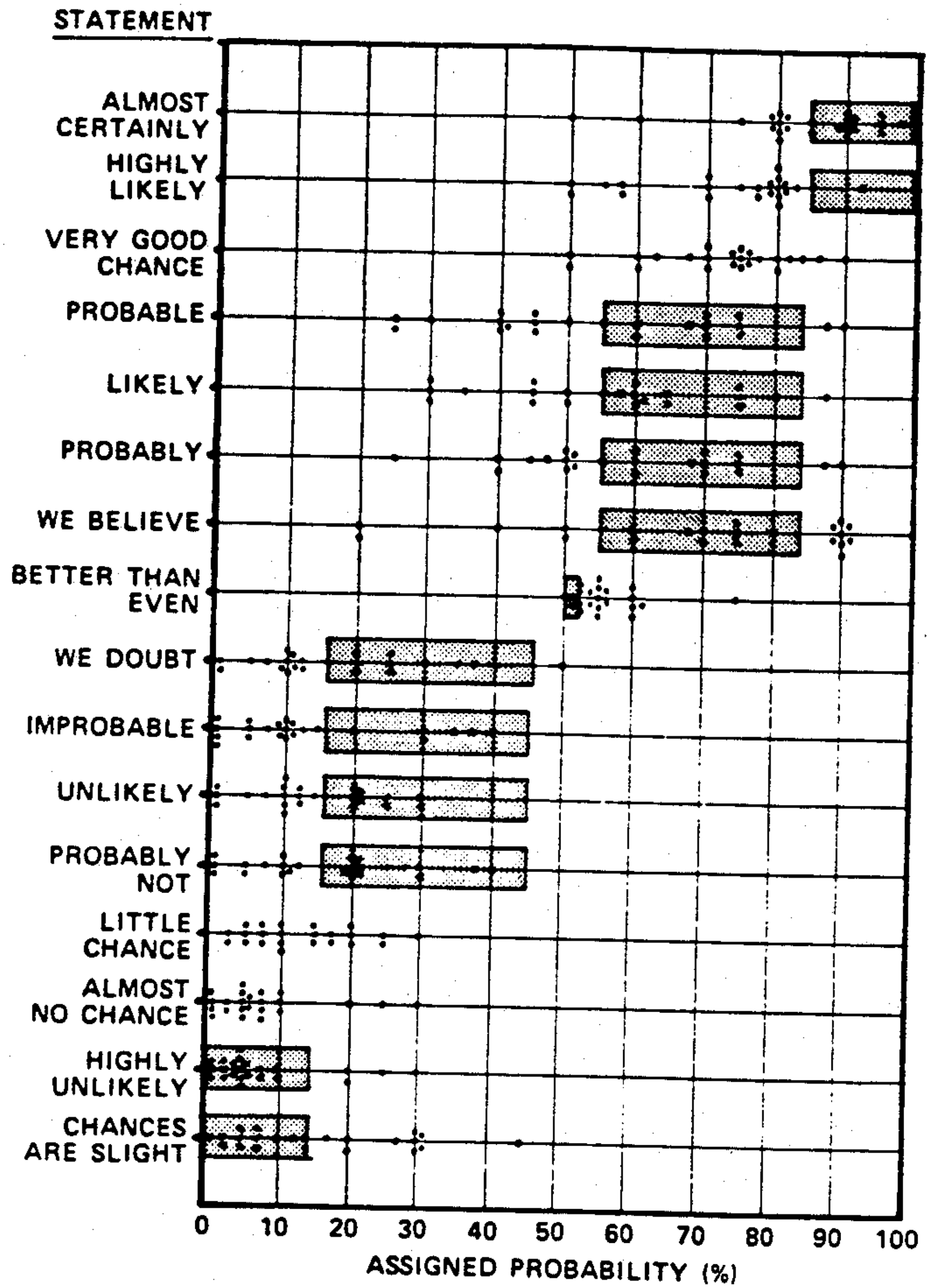

Figure 13-1
Illustration of Value Range of Expert Opinion Using Qualitative Descriptors

Source: Risk Assessment Techniques, A Handbook for Program Management Personnel, Defense Systems Management College, Fort Belvoir, Virginia, available from the U.S. Government Printing Office, First Edition, July, 1983, p. D-2, "What Uncertainty Statements Mean to Different Readers" experience and judgment, is held in contempt by everyone except the evaluator performing the analysis. The key to successful use of FLAIM lies in the selection and training of the assessors to ensure consistency and uniformity of evaluations.

Based on the author's own experience as both a participant and facilitator in several Hazard and Operability (HazOp) studies on various petroleum processing units and chemical plants, it is recognized that ensuring consistency in the approach taken to estimate uncertain values, such as when defining range values, is important.

FLAIM was designed to permit quantification of a mixture of qualitative and quantitative responses to selected assessment questions. If there is not a clear understanding of what is meant by a particular qualitative descriptor, e.g., *high, frequently, low*, etc., then the validity of that input response is suspect. **Figure 13-1** illustrates this problem with regard to the possible value range assigned to qualitative descriptors when expert opinion is quantified.

FLAIM's design has sought to minimize this problem insofar as possible by frequent use of multiple choice questions that have specified a value range selection. However, other questions necessarily ask for the users' general assessment using non-defined qualitative descriptors. To facilitate a general understanding of such terms and reduce possible errors due of a risk-communication nature, it is recommended that each user group define criteria for applications of these qualitative descriptors as part of the FLAIM worksheet setup process.

For example, when addressing a question involving the frequency of occurrence of a particular event or action, it is suggested that criteria such as that presented in **Table 13-1** be established and used throughout the assessment process.

As part of FLAIM's implementation plan, it is recommended that all user group-leaders undergo a basic leadership orientation and training course (i.e., similar to a HazOp leader training course) that addresses, *inter alia,* issues of risk communication and the meanings of commonly used descriptors and criteria employed to characterize risk and the risk assessment process. User workshops designed to educate assessors and surveyors in application of the FLAIM software package is also suggested.

Table 13-1
Illustration of Suggested Criteria for Qualitative Descriptors

Descriptor	Criteria
Never/Negligible/Rarely	once in 100,000 years
Possible/Improbable/Doubtful	once in 10,000 years
Occasionally/Sometimes	once in 1000 years
Likely/Expected	once in 100 years
Highly likely	once during the design life
Frequently	once or more each year
Almost certainly/Ongoing	once each day or work shift

The descriptors used and suggested criteria will depend on both the particular question being asked and the users'/operators' risk preferences. This analogy also applies to consequence level descriptions such as when the severity of an oil spill is quantified using qualitative descriptors, i.e., negligible, small, minor, large, catastrophic, etc.

Table 13-2
Illustration of Consequence Criteria Using Qualitative Descriptors

Negligible	No effect on public health or safety; no damage to facilities; oil spill of 10 bbl's (420 gallons) or less
Minor	No serious injuries or loss of life; little damage to facilities, no out-of-service time; oil spill of 420 to 10, 000 gallons
Major	Possible serious injuries or loss of life to some working facilities-related personnel, but no injury or loss of life to public; oil spill of 10,000 to 100,000 gallons; limited damage ashore to non-facility areas
Severe	Injury or loss of life to small number of public, or injuries or loss of life to substantial number of facility personnel; substantial facility damage, results in out-of-service condition for major part of system; oil spill of 100,000 to 15,000,000 gallons; substantial onshore damage to non-facility areas (i.e., substantial environmental damage)
Catastrophic	Substantial loss of life to public; facility damage essentially eliminating major part of system; extreme irreversible environmental damage that could not be mitigated oil spill greater than 15,000,000 gallons

Notes: Estimates of volume of oil spill up to category of severe are based on definitions in National Oil and Hazardous Substances Contingency Plan, (Council on Environmental Quality, February 1975; EPA July 1982) and on California's Oil Spill Contingency Plan (State of California May 1983). Oil spills are unconfined and reach either a body of water or unpaved ground.

For example, in the Environmental Impact Report prepared for a production platform[4] planned for the Pacific OCS region during the mid-1980's, the definitions of consequence severity as shown in **Table 13-2** were used.

The quantification of human and organizational error has only recently begun to receive the serious attention of researchers. Bea and Moore[5] have made significant progress over the past three years in developing quantitative models and methodologies for examining human and organizational errors (HOE) in the operation of marine systems. It is now generally recognized that only through improving the characterization and management of HOE risk factors can further strides be made to improve the offshore safety record. In this regard many opportunities exist for further research and development.

At present, there is insufficient data to develop meaningful objective probabilistic forecasts for offshore fires and explosions. It is believed that FLAIM can provide a basis for development of such data if used to assist accident and near-miss investigations. In this regard, it is recommended that further research be devoted towards developing a protocol and software interface with FLAIM to facilitate capturing vital information on platform accidents and near-misses. It is believed that such information could easily be incorporated into the existing structure of FLAIM's architecture in order to provide interactive access to new or existing proprietary databases.

Continued work is needed in refining and optimizing FLAIM; as mentioned in the introductory chapters, this will no doubt occur as part of its natural evolution through increased usage. However, it is also believed that a demonstration and validation study should be performed in the near future that involves several representative production platforms from different geographical locations, e.g., GOM, Pacific Region, GOA, etc. In this manner, FLAIM's utility and adaptability can be effectively tested and improved. In this regard, more attention is also warranted for developing a formal technique for updating FLAIM with a view towards continually improving reliability with each successive use.

The addition of an assessment module addressing life safety risk factors specific to those platforms handling hydrogen sulfide containing production fluids would be useful. In addition, further development of an economic analysis component of the software package incorporating the ACBM procedure as presented herein would assist users in the decision making process.

One area of further research having immediate interest is the possibility of combining FLAIM with the Human and Organizational Error Data Quantification System (HOEDQS) developed by Moore[6] and Bea. It is believed that as research progresses on identifying and characterizing human and organizational errors in meaningful ways, an immediate benefit will be realized in decreased loss rates and improved safety awareness. Combining the best features of FLAIM and HOEDQS would also serve to promote further research in the integration of human and organizational considerations in the application of the traditional engineering disciplines. Such research is considered essential in order to arrive at truly multi-disciplinary systems engineering solutions to the continuing problems of safe operations offshore.

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[1] Risk Assessment Techniques, A Handbook for Program Management Personnel, Defense Systems Management College, Fort Belvoir, Virginia, available from the U.S. Government Printing Office, First Edition, July, 1983, pp. II-2 -- II-4

[2] Dalkey, N., *The Delphi Method: An Experimental Study of Group Opinion*, The RAND Corporation, Santa Monica, CA, 1968,

[3] Personal correspondence from Professor R.G. Bea to W.E. Gale, Jr.

[4] Platform Julius was originally designed for Occidential Petroleum Company for the San Miguel lease in Southern California. The project was later taken over by Cities Services who sold their interests to Shell Oil. The design was complete but the platform was never constructed due to permitting problems.

[5] Bea, R.G., Moore, W.H. (1993) Operational reliability and marine systems. *New Challenges to Understanding Organizations.* In K.H. Roberts (ed.). Macmillan: New York. pp. 199-229.

[6] Moore, W.H. (1993) Management of human and organizational error in operations of marine systems. Doctor of Engineering Thesis, *Naval Architecture and Offshore Engineering*, University of California at Berkeley. (In prep.)

APPENDIX A

FLAIM USER INSTRUCTIONS

This first version of FLAIM has been designed to run in an Apple Macintosh II domain using Microsoft Excel, (version 4) software. At least four megabytes of RAM and a math co-processor is recommended. A color monitor is preferred but not necessary. Future versions of FLAIM will be designed for use in both PC-DOS and Macintosh environments.

To engage FLAIM:

1. Open "FLAIM" Disk by double clicking on the FLAIM Icon or name

2. Open the "FLAIM" application file

3. The startup window appears; click on the "START" button to engage FLAIM

4. A window will appear entitled "Platform Identification Information".

   4.1 Enter requested information as applicable.

   4.2 Type in all the important information before you click on "OKAY" or press the Return key. To move between input boxes, use the mouse and click in the box you wish to put information in.

   4.3 Click "OKAY" or press Return.

   4.4 Platform ID information cannot include "", /, - , +, = signs. A "bottom line" "___" is suggested to separate words or phrases.

5. A window will appear asking whether the user is performing a new platform assessment or modifying an previously run platform assessment. Click on the appropriate button and click "OKAY" or press Return. If it is a new assessment, FLAIM will create a new template. If it is a modified assessment, FLAIM will search for the platform assessment selected, and recall that information.

6. Another window will appear asking if you wish to setup a FLAIM input spreadsheet or perform a FLAIM assessment.

7. If the user is modifying or working with a previously performed assessment, a window will appear asking if you would like to Modify FLAIM input spreadsheet or perform a FLAIM assessment.

7.1 If Modify FLAIM input spreadsheet is chosen, it allows the user to select further questions at whatever tier level desired to be transferred to specified FLAIM assessment worksheet.

7.2 If Perform FLAIM assessment is chosen, it will directly go to the FLAIM assessment sheet for data input. This is based upon a previously established set of questions from the FLAIM spreadsheet.

8. The next window asks if the H_2S levels are higher than 20 ppm. If yes, it will halt the Macro and notify the user that a separate lifesafety assessment is necessary which is beyond the scope of FLAIM but will be included in subsequent versions of FLAIM.

9. Fire and Life Safety Assessment Options Window: The next window that appears allows the user to select the particular assessment of interest: General factors, LOCA, VESA, LACA, OHFA, RIRA, LISA, or SAMSA. The user selects the assessment that they wish to perform and clicks "OK". This window can be recalled upon completion of any particular section to allow the user to select another assessment to be performed.

A new assessment would normally begin with "General factors" and proceeds through each subsequent assessment module as listed in the options menu.

10. The next window will let you know that you can begin your FLAIM assessment.

11. A prior window asked whether a new or modified assessment is to be performed. If the assessment is new, then FLAIM has been designed to provide the user with the list of questions within the assessment category chosen (General, LOCA, etc.) from which the user is asked to make specific selections appropriate for the platform under consideration.

Each question can be assigned a corresponding tier level indicative of the assessor's perceived importance of each question (See Chapter 11 and Chapter 12: Tier 1, Tier 2, Tier

3). Upon selection of the tier level, FLAIM automatically assigns a default weighted value (See Table 11-3).

The user has the option of performing the assessment either at a Tier 1, Tier 2, or Tier 3 level of detail. In the question selection process, the user may elect to identify questions in either a single tier group or for all 3 tier levels depending upon the assessment needs of the platform.

A Word Bbout Tier Level Selection and Assessments

FLAIM has been designed to permit the user to increase the detail and depth of an assessment by selecting a higher tier level. For example a user performing a Tier 1 assessment may find sufficient cause to warrant a more in depth review of the platform e.g. in greater detail. This may be done by selecting a Tier 2 or Tier 3 assessment level by clicking upon the appropriate button in the window. When the user decides to perform a higher tier level assessment all of the questions of the preceding tier level assessments are automatically included in the new assessment.

Another unique feature included in FLAIM's design permits the user to modify the weighted value of any single question independent of chosen tier value. The way to accomplish this is addressed below in the description of the FLAIM assessment sheet.

12. Two methods are available to select questions to be assigned to each tier level. By directly entering the value into the appropriate cell under the heading of "TIER" or by clicking on the "Select Tier Level" button. If the "Select Tier Level" button is chosen, a window will appear asking the user to select the tier level that the user wishes to choose questions for. For example, if Tier 1 is selected in the "Select Tier Level" window, double-clicking the tier cell of the question list will automatically enter the value of "1" representing "Tier "1 into the cell.

The only purpose of this spreadsheet is to select questions for inclusion in the platform assessment process. Questions are selected by assigning a tier value. Any question, in which the tier value remains blank is excluded from the assessment process.

Any questions that have an "*" in the tier level cell and are shown in red shading, have been already identified as highly relevant to the importance of platform safety in all cases and are automatically included in the assessment sheets on a default basis. These questions need not be selected at any tier level since they are automatically included in the assessment sheet.

13. The user selects the appropriate questions by indicating their tier value. The next step is to copy these questions to the assessment worksheet by clicking on the green button entitled "Copy Questions to Assessment Sheet". Normally the first assessment performed by the user is a Tier 1 assessment (e.g. initial screening). Therefore, it is anticipated that the user would first select all Tier 1 questions to be copied to the assessment sheet and to then perform the assessment before selecting and copying Tier 2 and/or Tier 3 questions. If a user wishes to include Tier 2 and/or Tier 3 questions in the assessment, it is important that they have previously copied the preceding tier level questions to the assessment sheet.

14. Once the "Copy Questions to Assessment Sheet" button is pressed a window appears asking the user to input the tier level that is to be copied to the assessment sheet. Upon selection, press "OKAY". (Note: The user has the option of running each FLAIM assessment category at a different tier level in accordance with the perceived needs of the platform. For example, it may be decided that a Tier 3 Level Assessment is appropriate for evaluating LOC events, whereas, a Tier 2 level assessment is adequate to assess LACA.)

Upon completion of the copying process, FLAIM returns the user to the question selection sheet. It is then the users option to:

(1) select further questions of a different Tier value to copy to the assessment sheet,
(2) to return to the FLAIM assessment menu click on the red button entitled "Return to FLAIM Assessment Menu" in order to select a different category of questions
(3) activate the assessment sheet to begin the assessment process by clicking on the yellow button entitled "GOTO Assessment Sheet".

15. **GOTO Assessment Sheet:** Beginning the Assessment Process

The "GOTO Assessment Sheet" button on the question spreadsheet activates and sends the user to the assessment spreadsheet. The assessment sheet contains all of the previously selected Tier 1 through Tier 3 questions and default questions identified as "red-level" questions.

The first step in the assessment process is to assign weights to "red-level" questions and range limits for numerical questions (see Section 11.1.3 and Section 11.3.1). The column to the right of the FLAIM questions are where the user inputs the value, grade, or binary input to the question (see Chapter 11).

Each input cell is color coded to indicate the type of data required and the status of the cell. Red cells are "red level" questions that require the user to input a corresponding weighting value. The weighting value is relevant to the perceived importance of the question. Yellow cells indicate numerical questions that require the user to input the range limits for the variable of interest. By double clicking on yellow cells, a range window is called up that allows discretization of a continuous variable in qualitative levels from excellent to bad.

For example, platform age is discretized by double clicking on the yellow input cell to the right of the age question which brings up a range limit window. The user in this case selected five grading levels that correspond to a qualitative rating from "Excellent" to "Bad" reflecting concern over this risk factor. A platform less than five years old may be considered "Excellent", between 5-10 years "Good", between 10-15 years is "Fair", between 15-20 years is "Poor", and platforms greater than 20 years old are rated as "Bad" with respect to this risk factor (e.g. no age credit is given to a platform more than 20 years old). Similarly, other numerical variables for each question requiring discretization are assigned range limits in accordance with the user's judgment. Once the value range has been entered and the "OKAY" button has been clicked, the user will note that the yellow cell has turned to white.

Certain questions have been designated as "red-level" questions that may warrant a higher weighting value than Tier 1 questions due to their relative importance to overall platform fire and life safety. The user has the option of assigning a unique weighting value to this question that reflects its importance. The user indicates the perceived relative value of these questions by inserting a suggested weighted value with a higher number for more important questions. A value of 5 means that the user considers this question to be the same as a Tier 1 level question, e.g., the question is at least as important as a Tier 1 question but not more so. Higher values indicate that user believes the question to be particularly significant. See Table 11.3 for default and suggested relative values of Tier level questions. Once weighting values have been assigned to a red-level question, the input cell color changes from red to white for non-numerical questions, or to yellow if the question requires setting the value range.

Any white colored input cell to the immediate right of a question (column C on the Assessment Worksheet), when double clicked, results in a window message that instructs the user in how to change the weighted value of the question from its default value. This applies to all input cells that are initially white in color as well as previously colored red and yellow cells.

Black colored cells to the right of a questions (column C on the Assessment Worksheet) indicate that no input is required in that cell.

16. Once all of the input cells are white in color (except for black colored cells), the questions are ready to be answered. If an input is not entered into a white input cell, an alert window appears indicating that the user has overlooked or otherwise failed to answer a question. FLAIM will automatically activate the cell or cells requiring input for user convenience. Once all of the questions have been answered, FLAIM is ready to perform its assessment of the information provided. This is accomplished by clicking on the green button labeled "Calculate Assessment Risk Index."

17. The procedure is repeated for each of the risk assessment modules contained in FLAIM, e.g., General, Loss of Containment Assessment (LOCA), Vulnerability to Escalation Assessment (VESA), etc. After each of the assessment modules has been completed, the user can calculate the Overall Fire and Life Safety Indices by clicking the magenta colored button labeled FLAIM Summary. The FLAIM Summary window displays the risk indices from each individual assessment module and the overall composite fire and life safety indices

It should be noted that in keeping the intent for flexibility, FLAIM's algorithm for calculating the overall fire and life safety indices can be adjusted by the user to permit high or lower weighting value assignments of any particular assessment module. Hence, in the event that, for example, the user believes that Layout and Configuration Assessment is significantly less important than for example, Vulnerability to Escalation Assessment, the relative weighting values for these may be adjusted accordingly in order to arrive at a meaningful composite index.

APPENDIX B

ASSESSMENT OF RISK CONTRIBUTORS

APPENDIX B1

GENERAL FACTORS ASSESSMENT

B1.1 Platform Description

Physical Description:

Age of platform

Months since last complete turnaround

Has major modifications been performed to platform process systems subsequent to first oil (initial startup)?

Are there special requirements for materials of construction for piping and equipment, e.g., NACE MR-01-75, *Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment*, etc.

Age of production trains (average)

Age of gas compression equipment (average)

Age of combustion gas turbines (average)

Deck area

Number of drilling rigs

active development drilling taking place?

average persistence of workover operations† (usually ongoing, frequent - 1/month, occasional - 3 or more annually, infrequently

Number of deck levels

Number of Jacket Legs

Water Depth

Distance from Shore

Approximate response time for emergency service vessel assistance

Deck height above sea level

Number in normal crew contingent

Number of contract personnel routinely onboard

Size of Living Quarters

Helideck Provided?

† Including removal and testing of downhole safety valves

Open or Enclosed Decks

open on all sides

open on sea sides with longitudinal separation w/ bulkhead walls

open between decks (grating)

enclosed modules

negative mechanical ventilation provided in process areas?

positive mechanical ventilation provided in electrical equipment areas?

Wellhead Breakdown:

Number of completed production wells

Oil, Gas, and

Dual Completions

Number of completed water injection wells

Number of completed gas injection wells

Number of production wells capable of unassisted flow

Number of well flowing unassisted with wellhead pressures above:

500 psi

1000 psi

5000 psi

Number of wells with downhole pumps (electrical and hydraulic)

Number of wells on gas lift

Number, Size, and Normal operating pressure of export risers:

Oil

Gas

Number, Size, and Normal operating pressure of import risers:

Oil

Gas

Process Description:

Number of Production separator trains

Number of Production test trains

Total Onboard Production Compressor Horsepower

Total Onboard Gas Injection Compressor HP

Diesel driven, Gas Turbines, or other?

Daily Average Throughput:

Crude Oil (bpd)

Gas (mmcfm)

Condensate (bpd)

Mole % H_2S in gas, first stage separator

Mole % H_2S in gas, first stage of compression

Mole % H_2S in gas, import and export risers

Onboard fire heaters?

direct fired process treaters?

indirect fired treaters?

direct fired Glycol regenerator?

steam generators on board?

Utility Description

Onboard Power Generation Horsepower, Production and Drilling

Onboard Water Injection Horsepower

Diesel Engine, Gas turbine, or other driver

General Control Description:

highly automated computer based distributed/PLC control

limited automation, manual control from control room

primarily local pneumatic control

Fully Compliant with API RP 14C

Does the production system lack safety and backup (redundant) systems and devices normally provided for other similar platforms?

Would any aspect of design or construction be prohibited by current codes, regulations, standards, or are otherwise not in compliance with recommended practices? Specify

Does this contribute to an increased risk of fire, explosion, or risk of injury to personnel

Date of Last MMS and USCG inspections?

General Condition of Platform:

Excellent, Good, Fair, Poor, unknown

are topside safety systems and equipment outmoded?

are topside safety systems and equipment reliable are safety and control systems designed to facilitate full functional testing without interruption of production?

if not, are safety and control systems fully tested, even though platform production is shut-in

General Assessment of Crew Makeup:

experienced, highly qualified and trained Company employees

newly trained and qualified company employees

inexperienced and newly recruited employees

trained and experienced contractor employees

unknown

frequency of crew change/length of towers

are shift supervisors/foremen experienced, highly qualified and trained Company employees? minimum 10 years, 5 years, less than 5 years experience.

Operational Considerations

Perceived Consequence Level of platform:*

High

Average

Lower than average

Unknown

Have any fatal accidents ever been experienced?

Number or accidents involving fatalities

Number of fatalities/operating years

Were any of these caused by other than human error?

If yes, was mechanical/material failure on onboard equipment involved

Have any major fires and/or explosions occurred on the platform

Number of major fires and explosion

Were any of these caused by other than human error?

If yes, was mechanical/material failure on onboard equipment involved

* FLAIM considers all normally attended production platforms that are provided with a Living Quarters (LQs) as "High Consequence Platforms" with regard to lifesafety. Manned production platforms not equipped with LQs are deemed to be "Moderate Consequence Platforms;" and those facilities that do not meet the criteria for being manned are judged to be "Low Consequence Platforms" with regard to lifesafety

Have any major oil spills occurred on the platform
Is either internal or external corrosion a significant LOC factor
Does welding and other hot work routinely occur on the platform
Does the production process have more than one operating mode requiring different operating procedures and emergency response actions?
Are alternative operating modes followed: frequently, occasionally, rarely, never.
Do service conditions change substantially from mode to mode
Are any of these conditions not part of the original design
Have control systems been changed from initial design
Have any emergency shutdown (ESD) valves (process isolation valves) been removed from service
Have additional bypass, feed, interconnects, crossover/jumpover lines been added to the process system
Are Piping and Instrument Diagrams up to date
Do reservoir production characteristics make it difficult to maintain target production levels
Does the platform have problem wells that require special attention to avoid process upsets
Are there particularly hazardous operating conditions that are occasionally or routinely encountered
Do process excursions routinely occur which require timely intervention to prevent unsafe conditions: often, occasionally, rarely, never
In a typical process upset, will an unsafe condition result if operator response does not include doing at least one action, two actions, three actions, more than three actions.
To prevent an unsafe condition, operator response must occur within one minute, two minutes, five minutes, ten minutes, within thirty minutes, from time of first alarm in the event of:

High level alarm in flare knockout
High level alarm in compressor scrubbers (any stage)
High level alarm in first stage separators
Fire alarm, wellbay

Can operator control and shutdown/depressure process for the control room

Do instrumentation and control systems frequently malfunction

Are there frequent operational problems affecting platform safe operating conditions

In general is equipment reliability a problem

Are operators required to routinely perform testing/sampling/gauging functions that require opening sample/vent valves and drains, fill connections, or use of transfer hoses to perform duties.

Do personnel other than operators routinely work in and around wellheads and process equipment

Do non-operators become involved in opening process equipment or lines containing hydrocarbons?

Are temporary repairs frequently made between turnarounds: often, occasionally, rarely, never

Do contractors routinely work in and around operating process equipment and piping

APPENDIX B2

LOSS OF CONTAINMENT ASSESSMENT (LOCA) FACTORS

A Loss of Containment (LOC) event is a precursor to most anticipated fire scenario* involving flammable liquids or gases. The potential resultant fire scenario depends both on the fuel characteristics and the amount of fuel that may be initially released.

B2.1 FUEL FACTORS

Total inventory of flammable hydrocarbon liquids resident within the process system, including topside storage of crude, condensate/natural gas liquids (NGLs), diesel fuel, aviation fuels, methanol, ethylene glycol, and other flammable liquids that are present onboard the platform.

Fuel Types -- Production Fluids

Pressurized Natural Gas -- Predominately Methane (CH_4)†

- Wet, untreated production gas containing condensables
- Dry, dehydrated/treated sales gas for export
- Dry, dehydrated/treated reinjection gas for pressure maintenance
- Dry, dehydrated/treated gas-lift gas for recovery assistance
- Dry, dehydrated/treated fuel gas for platform utilities

Natural Gas Liquids (NGL)†† -- Predominately and C_5+ (natural gasoline)

- Unstabilized Gas Condensates containing C_2, C_3 & C_4
- Stabilized Gas Condensate (light ends removed)

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* Exceptions include fires in atmospheric storage tanks and vessels in which the vapor space is normally within the flammable region or otherwise comes to be within the flammable range due to , for example liquid withdrawal resulting in air intake. If a source of ignition is present, or introduced, under such conditions, such as pyrophoric iron sulfide or lightning, an explosion and/or fire may result, without having been preceded by an LOC event.

† Characterized as lighter-than-air flammable gas

Liquefied Petroleum Gases (LPG)[††]

- Pressurized liquid propane and butane recovered from NGL

Crude Oil

- Live Crude (light crudes containing dissolved gases and volatile components)
- Dead Crude (heavy, viscous crudes with low volatility)

Fuel Types -- Non-production Fluids

- methanol
- ethylene glycol
- diesel
- oil-based drilling mud additives
- lubricants
- aviation gasoline/kerosene
- fuel oil
- motor gasoline
- hydraulic fluids
- lubricants

Fuel Containment Conditions

Process System Inventory (Pressurized Production Fluids)

The amount of potential fuel (produced hydrocarbons) resident within topside process systems, assuming all riser and wellhead safety valves are closed and topside process systems are isolated (blocked-in). Including production separators, slug catchers, test separators, heater treaters, and headers and manifolds. Also include topside pressure storage of NGL and LPG. Gaseous production inventory may be excluded if the process system has a depressuring system that meets API RP 521 criteria.

[††] Characterized as heavier-than-air flammable gases when vaporized; liquids such as butane, ethane, propane, and natural gas liquids (NGL) and mixtures thereof with vapor pressures exceeding 40 psia @ 100°F are termed "Highly Volatile Liquids" or HVLs. These materials vaporize at low temperatures, e.g., have low flash points, and when released to the atmosphere, will rapidly vaporize to form large volumes of cooled gases with densities exceeding air density, e.g., they present a high fire and explosion risk. [See API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, American Petroleum Institute, First Edition, June, 1991, p. 11].

Process System Inventory (Non-pressurized Production Fluids)

The amount of above deck crude oil and storage at atmospheric pressure.

Process System Inventory (Pressurized Production Fluids

The amount of above deck pressurized storage of natural gas liquids/condensate and LPG.

> [Note that unpressurized storage of natural gasoline and other lower vapor pressure natural gas liquids should be specified separately with Non-pressurized Production Fluids]

Non-process System Inventory (Non-pressurized Non-production Fluids)

The amount of above deck flammable & combustible liquids in storage at atmospheric pressure.

Storage Conditions

Are storage tanks well maintained

Are flammable liquid storage tanks made of fiberglass or other plastic materials; or are tanks that have been erected using sectionalized bolted steel plate present on the platform.

Have high level alarms and overflows been provided to prevent overfills

Are all drain valves double blocked with plugs or a second valve?

B2.2 Wellbay LOC Factors

Number of high pressure wellheads (above 1000 psi) within the wellbay

Spacing between wellheads (LACA)

Pressure Drop across Choke

Average Operating Time-to-Closure of Surface Safety Valves

Surface controlled subsurface safety valve installed?

B2.3 Import/Export Risers

Operating pressures and flow rates of platform oil and gas import/export risers

Size and age of platform oil and gas import/export risers

Date of last metallographic inspection/cracking found?

Do export risers have check valves installed

Do risers have underwater safety valves installed?

Forecast remaining service life based on metal loss data trend

Are risers located

below or adjacent to crew quarters

cellar deck storage crude oil tanks

near ignition sources

in an area susceptible to damage from dropped objects or vessel impact

Has/Does a riser:

ever leaked

corroded/pitted

cracked

been dented or impacted

vibrate/suddenly move

been exposed to fire

been welded on

fireproofed

been welded on

B2.4 Platform Design Capacity and Operating Conditions

Does platform crude oil and gas production throughput (actual) exceed original design capacity (as-built)? By what % over initial design?

Was platform process facilities ever expanded to accommodate an increase throughput capacity?

Were platform pressure-relieving systems (pressure relief and depressuring systems) increased in capacity

Were platform drainage systems increased to meet higher flow capacities?

Is any process component operating above its maximum allowable working pressure?

Has the Gas Oil Ratio (GOR) of unstabilized crude changed from initial design conditions?

Has hydrogen sulfide (H_2S) content of production fluids increased above design basis?

Has Basic Sediment & Water (BS&W) levels/sand production increased

Is flowline, choke or header erosion a significant factor

Is platform equipped with Sand Probes

Do separators experience slug-flow

Average operating pressure of first, second, and third stage production separators.
Discharge pressures of crude shipping (pipeline) pumps
Discharge pressure of gas compressors; both shipping and reinjection
Type/number/size (hp) of gas compressors
Number of production separator trains onboard
Number of stages of separation in each train

B2.5 Material compatibility for service conditions

Modifications to the process system during its service life:
Has weld quality been assured by testing and inspection
Have service ratings of piping and equipment components been verified for the service conditions
Do service ratings of these components meets or exceeds those required for the actual service demands for the system
Can all "as-built" materials-of-construction used to fabricate process components for production system modifications be accounted for (are known, documented, and verifiable)
Has material suitability been assured for service conditions
Have all piping components and pressure vessels been post-weld heat treated to reduce cracking susceptibility
Has the production system been reviewed to ensure that:

1) all pressure containing equipment, piping, and piping components meet or exceed the maximum allowable pressure rating specified for that section of the process system within which they are installed

2) all pressure containing equipment, including flowlines, headers, pressure vessels and piping components that are rated for service lower than the maximum wellhead tubing shut-in pressure, pump or compressor discharge pressure, or can otherwise subject to overpressures above their MAWP due to operational upset or instrument failure† are equipped with suitable pressure relieving devices as called for by RP-14C

† For example, low of pressure vessel level control in a high pressure separator allowing high pressure gas to enter a low pressure separator, e.g., "Gas-Blowby." This occurred on March 22, 1987 in British Petroleum's Grangemouth Refinery in which a low pressure separator was severely over pressured and catastrophically failed, killing one man and projecting a three ton piece of the fractured vessel more than 1100 meters. Refer to: Atherton, J., Hydrocracker Explosion & Fire, B.P. Grangemouth Refinery, 22 March, 1987, paper presented at the 1988 mid-year meeting of the American Petroleum Institute Refining Department of the Operating Practices Committee, May 10, 1988.

Have high strength steel/alloys been used for fabricating topside production equipment, e.g. wellheads, pressure vessels (separators), and other system components in wet H_2S service

Have these components been inspected for cracking using wet magnetic particle fluorescent inspection techniques.

Have any failures in production system occurred to SSC or CSC of components

Are such failures are a continuing problem.

Are metal loss corrosion rates negligible, mild, moderate, high, or severe in accordance with table B2-1:

Table B2-1

Annual rate of metal loss v. corrosion severity

Rate of annual metal loss	Corrosion Problem
2 mils or less	negligible
between 2 to 10 mils	mild
11 to 25 mils	moderate
above 25 mils	high -- consider material change
above 100 mils	severe problem/ high LOC risk

Is the quality of a platform's in-place corrosion detection, monitoring and control program excellent, good, fair poor, or unknown.

Is platform gas sour, e.g., do gas systems that are operating at pressures above 65 psia contain H_2S at a partial pressure above 0.05 psia sour.
[Example: a gas stream at 1000 psia that contains 100 ppm of H_2S (0.01 mole %) would have a H_2S partial pressure of 0.1 psia, and therefore is considered sour]

Are corrosion coupons being used

Are corrosion rates trended to predict remaining useful life

Are CIHH pressure vessels inspected at least: once each year, once every two years, once every five years, unknown.

Are CIHH piping systems inspected at least: once each year, once every two years, once every five years, unknown.

Is the inspection interval determined by corrosion rate trending

Have process conditions significantly changed since the last major turnaround

Does the platform have a cathodic protection system

Are corrosion inhibitors being injected into the process systems to control corrosion

Are any high pressure gas piping systems or risers presently in need of (overdue for) inspection

Is erosion a problem in platform piping systems

Are fluid flow line velocities exceeding original design criteria

Are fluid flow line velocities exceeding the recommendations of API RP 14E

Is produced sand in well fluids a contributing factor to erosion

Are sand probes or other active means of detection installed in key segments of the process system where erosion is most likely anticipated.

Have vibration induced fatigue failures occurred in small diameter piping

Is vibration of piping systems: common throughout the platform, occurs only in a few systems, is limited to one or two systems, is not noticeable problem

Are pipe pressure-rated valves freely hung off of small diameter piping without other means of support

Is small piping that is subject to vibration gusseted or otherwise properly supported.

Is small piping in hydrocarbon service: socket welded, or, if threaded, have the threads have been seal-welded -- completely covering all exposed threads.

Are vibration monitors provided on all CIHH rotating equipment such as compressors and shipping pumps

Do vibrations monitors sound alarms and shut down equipment automatically

Is there any large diameter hydrocarbon handling pipeline on the platform that is subjected to vibration from slug flow, surging, or other cyclic force that is causing it to either occasionally or constantly move more from its centerline in any direction more than: 1 inch, 2 inches, 4 inches, 6 inches, more than 8 inches

APPENDIX B3

VULNERABILITY TO ESCALATION (VESA) RISK FACTORS

VESA factors* are designed to assess those features or deficiencies in topside design features and the state of operations that may contribute to the inability to:

1) rapidly control, direct, and stop a LOC incident before ignition occurs,
2) prevent ignition after a release has occurred
3) control the initial fire size and its resulting thermal impact on adjacent equipment and piping, and
4) prevent a further cascading of LOC events and vulnerability to escalation

B3.1 Equipment Risk Factors

General age and state of topsides production systems and equipment:

- uniformly new (less than five years old)
- uniformly used (less than ten years old)
- uniformly old (between ten to twenty years old)
- mixture of new, used, old equipment
- very good condition throughout (reliable, not patched or repaired, no leaks)
- good to fair condition (generally reliable, few to no temporary patches or repairs, minor leakage and emissions common to most operations)
- fair to poor condition (marginally reliable, old equipment, frequent breakdowns and general leakage, extensive repairs)
- uniformly poor condition (routine upsets and breakdowns, mechanical and material failures common, general leakage and extensive repairs)
- Have corrosion trends and life expectancies been established for all process components
- Average remaining life expectancy of equipment based on corrosion half-lives: more than 10 years, 5 to 10 years, less than 5 years, less than 2 years, don't know.

* Some of the data relevant to VESA risk factors is collected in other Appendices

Have critically important hydrocarbon handling (CIHH) equipment items and piping systems been identified based on their potential for LOC events

Are routine inspections performed on critically important hydrocarbon handling (CIHH) equipment items and piping systems

Have process components in wet H_2S service been inspected for cracks using wet fluorescent magnetic particle techniques

How often is CIHH equipment and piping inspected

How is CIHH equipment and piping inspected:

Are small piping systems in high pressure service periodically radiographed?

Rotating Equipment

Flammable Gas Compressors -- General

The risk of fire and explosions from compressors depends on several factors including:

- the type and size of the compressor, driver, and lubrication system, as well as the temperature and pressure of the compressed gas
- the arrangement of the compressor area, spacing between units, the presence of other combustibles/fuels in the area
- adequacy of maintenance and inspection practices, provisions for shutdown, blowdown, (depressuring), and protective instrumentation, e.g., vibration monitors, design of pulsation dampeners and surge control, extent and amplitude of induced vibration in associated piping, provision of adequate ventilation, piping and welding practices
- combustible gas detection and fire detection systems, firewater deluge/water spray systems

Does the platform have onboard gas compressors

type (centrifugal, reciprocating, other)

number

horsepower

discharge pressure -- final stage

Is each suction, interstage, and discharge line equipped with:

Pressure Safety High (PSH)

Pressure Safety Low (PSL)

Pressure Safety Valve (PSV)

Is each suction and interstage scrubber equipped with:

Level Safety High (LSH)

Level Safety Low (LSL)

Are high-high level shutdown (LSHH) provided to automatically shut down the machine should operators fail to respond in sufficient time.

Is there a Temperature Safety High (TSH) on the discharge of each stage

Do the PSH, PSL and LSH on suction and interstage lines and scrubbers actuate automatic shutdown valves (SDVs) on the suction and fuel gas line to isolate the machine from all input sources.

Are vibration shutdown switches provided for each machine

Are SDVs located in a firesafe area

Do the SDVs automatically operate on shutdown of the prime mover

Do the SDVs automatically operate on fire and gas detection

Are SDVs provided automatic shutoff of all sources of hydrocarbons entering the compressor areas in an emergency†

Is a blowdown valve provided on the discharge line of all compressors:

regardless of horsepower

only for those machines above 1000 hp

not provided

Does the blowdown valve open automatically on fire and gas detection

Is the blowdown valve fail-safe, e.g., opens on power loss

Are PSVs set so as to not to exceed the MAWP of the system

Is a check valve provided on each compressor units final discharge line

Is piping designed for actual operating pressures and temperatures, thermal expansion, and vibration --

all 2" and larger piping welded

all 1-1/2" and smaller piping either socket welded or screwed and seal-welded or bridge welded

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† Sometimes small hydrocarbon lines, e.g., side streams, are unintentionally overlooked during facility modifications. In the event of a fire, such lines may quickly fail and escalate the fire scenario if not equipped with automatic shutdowns.

all 1-1/2" and smaller piping at least schedule 80 or heavier
is any threaded piping in hydrocarbon service smaller than 3/4"

Can flammable liquids or lubrication oils accumulate beneath compressor

Does each compressor have automatically operated shutoff valves at all suction and discharge lines that can be actuated from at least two separate and remote emergency shutdown stations/panels in the event of fire.

Does each machine have a remotely operated fail-safe, i.e., fail-open, depressuring system (blowdown valve or BDV) that will vent the machine to flare on actuation of the emergency shutdown system.

Are engine fuel gas valves equipped with automatic fail-safe (fail-closed) shutoff valves actuated via the emergency shutdown system.

Is each machine provided with a vibration monitor and automatic shutdown for run protection, as well as overspeed protection.

Reciprocating Compressors and Drivers

Is the Maximum Safe Working Pressure of the cylinders greater than or equal to the PSV setting

Are cylinder heads made of steel or forged steel and gaskets appropriate for the type of service

If clearance pockets (bottles) are shop fabricated (non-OEM), do they meet ASME specifications

Are threaded clearance pockets utilized

Have PSVs been sized for recycle backflow under all possible conditions

Is rated design temperature above actual operating temperature for all operating conditions such as 100% recycle and low suction pressure

Are spark-ignited internal combustion engine drivers equipped with solid state ignition systems

Is primary ignition wiring high temperature silicon rubber insulation or equal

Are ignition transformers (coils) mounted close to or at spark plugs

Are exhaust manifolds and piping water jacketed or insulated

Are spark arrestors provided on intake and exhaust systems

Have explosion doors been provided on all gas-fueled engines

Are engine drivers located in Class I Division 1 locations

Are engine air intakes located in a vapor-free area and provided with emergency closure devices*

Is there a current predictive maintenance/problem procedure

Are engine analyzers used to predicted maintenance needs and establish deterioration trends and predict major turnaround schedules

If there is a current predictive maintenance/problem procedure, is the procedure is based on manual interpretations of routine engine tests and operating data; or if the procedure incorporates trending analysis based on engine analyzers.

Centrifugal Compressors and Drivers

Is suction piping designed for maximum possible pressures caused by surge valve failure or recycle backflow

Are check valves installed on the discharge of each stage

Are overspeed governors provided

Are overhead seal oil tanks provided with overflows to the drain system

If multiple overhead seal oil tanks are supplied from one seal oil supply pump, are all overhead seal oil tanks designed for maximum seal oil pump discharge pressure, e.g., for the operating pressure of the seal oil tank supplying the highest stage of compression.

Is buffer gas carryover into the lube oil reservoir a frequent occurrence

Are gas turbines provided with splash barriers (walls) to reduce the risk of hot surface ignition in the event of a seal failure leak or similar event involving the release of hydrocarbons

Are gas turbines installed in accordance with the recommendations of API Standard 616, *Combustion Gas Turbines*,?

Are emergency shutdown controls provided for system redundancy, providing backup to primary shutdown functions.

Is an emergency shutdown initiated on: 1) overspeed, 2) flameout, 3) vibration and 4) fire detection/high temperature.

Are safety shutdowns routinely tested on a monthly basis or otherwise in accordance with current recommendations of the manufacturer.

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* Since May 31, 1989, OCS Orders have required that diesel engine air intakes be equipped with a means to automatically or, if normally attended, remotely shut down the engine by cutting of intake air. This can be accomplished by equipping diesel engine air intakes with airtight shutoff valves actuated by engine tachometers.

Has a platform combustion gas turbine ever started a fire on the platform

Has a platform combustion gas turbine ever initiated an explosion on the platform

Are platform gas turbines considered reliable

Do platform gas turbines have their own self contained fire suppression system

Pumps

Have all critically important hydrocarbon handling (CIHH) pumps been identified and categorized as high priority equipment items

Are/Do all CIHH pumps and drivers:

1) included in a preventative maintenance program
2) subject to a vibrational monitoring program that tracks and trends vibration levels for forecasting failures,
3) equipped with vibration alarms
4) equipped with bearing temperature alarms
5) have pump cases and shafts constructed of steel or steel alloy materials
6) have double mechanical shaft seals with seal failure alarms
7) have throat bushings to limit fluid flow in the event of seal failure,
8) have remote pump shutdown controls that can be quickly accessed by operating personnel in the event of a fire.
9) have automatic pump shutdowns switches and SDVs on inlet and outlet lines that are actuated by the ESD and fire detection system

Are motor operated (MOV's) or air operated (AOV's) SDVs either fireproofed or designed for fail-safe operation

Are pump case drain and vent fittings and similar threaded pump case connections have been seal-welded/bridge welded to minimize the risk of vibration induced fatigue failure

Electrical Equipment

Are platform motors, generators, and electrical distribution systems properly installed and protected in accordance with the recommendations of API RP 14F .

Is platform electrical equipment able to be safely and rapidly de-energized from a central location.

Does the platform have multiple electrical switchgear and motor control centers located in or directly adjacent to process areas?

If yes, are the switchgear and MCC equipment installed in Class I enclosures or provided with separate pressurized rooms designed in accordance with NFPA 496?

Fired Heaters

Are fired heaters of any type are located on a production platform containing wellheads and process equipment,

Are the type of **fired heaters** installed: protected,† natural draft v. forced draft, indirect v. direct, convection v. radiant

Are fired heaters separated from all other process equipment and located upwind of potential hydrocarbon releases

Protection provided: curbing and drainage, instrumentation/alarms, combustion controls, ESD, fire detection and suppression, flame arrestors, insulation, water-cooled jacketing, thermocouples

Does the platform have a fired glycol regenerator (reboiler or reconcentrator)

If yes, what the onboard fire experience has been in its operation: frequent fires, occasional fires, rare fires, never had a fire, do not know

Storage Tanks and Pressure Vessels

Do vapor recovery systems have approved flame and detonation arrestors

Have storage tanks been inert gas blanketed

Do all tank nozzles located below the highest possible liquid level have steel block valves located at the nozzle flange

Have thermally actuated automatic closing block valves been installed on all liquid fill and withdrawal lines.

† Are all fired vessels are designed as protected units (Low Ignition Risk) in accordance with the definition of API RP 500B, e.g., protected fired vessels are designed in such a way so as to eliminate the combustion air intake and exhaust stack and other hot surfaces as possible ignition sources.

Do tanks and vessels used for storage have overflows piped to a safe disposal area.

Have high level alarms and high-high level safety switch shutdowns on transfer pumps been installed in accordance with API RP 2350

Are venting provisions and alarm instrumentation in accordance with API RP 14C and API 2000 -- are atmospheric vents provided in accordance with API RP 2000

Are the structural supporting members of elevated storage tanks and vessels fireproofed or otherwise protected with fixed water spray deluge systems so as to retard collapse and allow time for fire-fighting efforts.

Are pressure vessels and their pressure-relieving devices are being inspected and maintained in accordance with Section 6, Alternative Rules for Natural Resource Vessels of API 510

Have pressure vessels in CIHH services been post-weld heat treated (PWHT)

Has documentation on engineering data and inspection results been maintained up to date.

Has wet fluorescence magnetic particle inspection been conducted to determine the extent of stress cracking that may be present in vessels in wet H_2S service.

Have vessels and piping in wet H_2S service been designed to NACE Standard MR-01-75, *Standard Materials Requirements - Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment*

Heat Exchangers

Have shell and tube exchangers been designed to the requirements of the ASME pressure vessel code, API standards 660 and 661, and protected in accordance with API RP 14C.

Has adequate relief capacity to prevent overpressure failures caused by fire exposure been verified to be consistent with the recommendations of API RP 521 [ref.: API RP 521, Guide for Pressure-Relieving and Depressuring Systems

Piping Systems and Components

Have all topside piping systems been constructed of seamless steel or steel alloy pipe

Are valves and fittings used in hydrocarbon handling services made of other than carbon steel, e.g., cast iron, malleable iron, nodular iron,† brass, cooper, aluminum, plastic and rubber and similar materials

Is all topside hydrocarbon piping seamless steel construction

Does all piping meet the requirements of ANSI B-31.3

Are all valves in hydrocarbon service that utilize soft-seating and packing materials tested to and meet the requirements of API Standard 607, *Fire Test for Soft-Seated Quarter Turn Valves*, American Petroleum Institute, Third Edition, November, 1985].

Are quick-connectors and compression sleeve couplings, e.g., Dresser couplings, Victaulic couplings, etc. used in hydrocarbon piping

Are pipe clamps/sleeves that rely on elastomeric materials to retain fluids and prevent leaks used for "temporary" repairs

If yes, how long have such clamps been in place

Have flangeless, wafer-type valves that are designed to be inserted and held in place under compression between two flanges used in hydrocarbon services, such as wafer-type butterfly and check valves.

Are flat face flanges used in hydrocarbon services

Have flanges been fire tested*

Are all flanged connections are provided with spiral wound gaskets

Are thermal relief valves provided in section of piping that could be liquid-packed when isolated by block valves

Are bellows-type expansion joints used in hydrocarbon services.

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† See API RP-14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems* (RP 14E), American Petroleum Institute, Fifth Edition, October 1, 1991, p. 31].

* API Bulletins 6F1 and 6F2 provide additional information fire test performance of API and ANSI flanges. See API Bulletin 6F1, *Fire Resistance of API/ANSI End Connections*, First Edition, November, 1, 1987, and API Bulletin 6F2, *Improved Fire Resistivity of API Connections*, First Edition, November 1, 1987, American Petroleum Institute].

Are vents and drains kept as short as possible and provided with double block and bleeds or bar-stock plugs/bull plugs

Have any sections of hydrocarbon piping systems have welds that were field-fabricated

What percent of the field-fabricated welds have undergone radiographic weld examination: 100%, 50%, 10%, 0%, do not know

Wellheads and Risers

Do wellhead assemblies meet the appropriate PSL specification for the service conditions

Are all Christmas tree valves and end connections certified for maximum leakage under fire conditions in accordance with API SPEC 6FA and API SPEC 6FB†

Is the mechanical integrity of platform risers known: date of last inspection

General condition of risers: excellent, good, fair, marginal, unknown

What is the frequency of detailed full-scope inspections

Are rises checked for cracks with appropriate inspection techniques

Are risers located adjacent to or under crew quarters

Do risers transverse horizontally across the lower (cellar deck)

Do export risers have check valves

Are risers equipped with underwater safety valves (USVs)

Have any platform risers currently in service been physically damaged (dented, etc.) or exposed to high temperatures

Have any platform risers been welded on

If yes, have the welds be radiographed

Have the welds been heat treated

Is any riser subject to slug flow

Is any riser subject to observable vibration

Have all platform risers been hydrostatically tested within the past five years

Is any riser experiencing high rates of corrosion

Is any riser experiencing erosion

Is any riser exceeding its design flow capacity or pressure rating

† See API Specification for Fire Test for Valves (SPEC 6FA), First Edition, May 1, 1985, Reaffirmed May 1, 1990; and API Specification for Fire Test of End Connections (SPEC 6FB), Second Edition, April 1, 1992, American Petroleum Institute.

Is any riser exceeding recommended safe flow velocities

Do all risers have SSVs

will they will close in less than 45 seconds

Surface Safety Valves (SSVs)

Do SSVs and their actuators meet the appropriate service class as specified in API Specification 14D[††]

Are SSVs inspected and maintained in accordance with API RP 14H[*]

Are SSVs tested for operation and for leakage at least once each calendar month, but at no time longer than at more than six week intervals in accordance with MMS OCS Orders

Does closure time for SSVs exceed the maximum 45 seconds allowed from time of actuating the ESD system or automatic detection of an abnormal condition by a safety sensor per MMS OCS Orders

Surface Safety Valves (SSSVs)

Are SSCSVs (storm chokes or velocity type valves) used in place of SCSSVs for any reason

If yes, are SSCSVs routinely removed and tested[++] in accordance with MMS OSC Orders

Are SSSVs in conformance with all testing and maintenance recommendations of API RP 14B[**]

Are SSSVs in conformance with maximum allotted closure times of 2 minutes from time of closure of the SSV

[††] See API *Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service* (SPEC 14D), American Petroleum Institute, Eight Edition, June 1, 1991

[*] See API *Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore* (RP 14H), American Petroleum Institute, Third Edition, Aug. 1, 1991]

[++] SCSSVs are required by OCS Orders to be tested for proper operation and leakage at least once every six months [ref. 30CFR §250.124, (a) (1), July 1, 1992 edition, p.237]. SSCSVs must be removed from the well and inspected on six to twelve month cycles depending on if the valve was installed in a landing nipple.

[**] See API RP 14B, *Recommended Practice for Design Installation, Repair, and Operation of Subsurface Safety Valve Systems* (RP 14B), American Petroleum Institute, Third Edition, January 1, 1990 and Supplement 1, January 1, 1993].

Some SCSSVs are equipped with isolation valves near the control line wellhead outlet. Closure of this valve will isolate the SSSV from the surface control system -- have management controls been put in place to ensure this valve is not accidentally closed or left in a closed position for an extended period.

Instrument & Electrical Systems and Equipment

Are Instrument & Electrical devices reliable: highly reliable, generally reliable -- occasional problems, routinely source of problem, very unreliable -- frequent cause of problems

Condition of wiring and cable: excellent -- no signs of deterioration, good -- occasional repairs required, fair -- showing signs of deterioration, poor -- advanced state of deterioration--frequent shorts, grounds and open circuits.

Are as-built instrument & electrical systems and equipment in conformance with API RP 14F: 100%, 90%, 75%, less than 50%, do not know

Are stray currents a known problem on the platform

Are system grounds difficult to maintain

Have any platform personnel incurred injury due to electrical shock from improperly installed electrical equipment

Have any fires involving electrical equipment been experienced in the past ten years: none, one, two, three, four, more than four.

Are cable trays used in unclassified areas

Are cable trays used in Class I Division 2 areas

Are metal clad and jacketed cables used to for power and instrument wiring.

Do cable trays pass through high fire risk areas

Are cable trays/cables protected from fire exposure

Would loss of any single group of cables cause loss of platform control, i.e., are dual data highways provided and independently routed for redundancy.

Are cables grouped together as they enter the control room

Do any automated safety shutdown valves depend on receiving power or control signals from cabling to function in an emergency, e.g., are not fail safe.

Are polyvinyl chloride (PCV) jacketed or insulated cables used on the platform

Are neoprene, Hypalon®, or polyethylene jacketed/insulated cables used on the platform

Have cable trays been provided with fire stops and fireproofing or water spray protection to prevent fire spread along cable trays and through cable tray penetrations at bulkheads and decks

Compressed Air System -- Explosion Risks

Has the platform every experienced a compressed air system explosion

Is noncombustible (fire-resistant) synthetic lubricating oils instead of conventional combustible lubricants

APPENDIX B4

LAYOUT AND CONFIGURATION ASSESSMENT (LACA) FACTORS

B4.1 *GENERAL ARRANGEMENT CONSIDERATIONS*

FLAIM assess the arrangement and configurations of topside facilities for firesafety and lifesafety risk factors.

General Considerations

Overall description of platform configuration:
- Good: well laid-out with good access to equipment and controls
- Fair: tight spacing and somewhat congested
- Poor: very congested, difficult to perform routine operations, maintenance, and inspections

Location of fire pumps and their placement relative to each other:
- are redundant platform fire pumps located together*

Location and configuration of escape routes and points of embarkation
- influence both travel distance, the time to escape, and the exposure of personnel to thermal impact and smoke:
- are topsides escape routes well marked and free from obstructions
- are escape routes located in a manner to minimize personnel exposure
- are escape routes routed directly to safe areas of embarkation
- are at least two escape routes provided in opposite directions from each high fire risk area on the platform
- are embarkation stations located on opposite sides of the platform

Location of the control room and radio room:
- is the control room/radio room located in a safe area of the platform
- do control instrument and cable home runs pass through high fire risk areas

Fire Compartmentation

* True redundancy requires separate locations segregated from mutual exposures.

Is the platform physically separated into designated zones of fire separation on each deck and between each deck level

Are fire zone separations both vertically and horizontally configured

Are fire zone separations rated assemblies, e.g. are bulkheads and decks fireproofed

Are penetrations in fire separations sealed

Are personnel doorways installed in firewalls

Are doors fire rated

Are access hatches between decks normally open

Are the penetration seals engineered to meet specific fire rating criteria

Are fire separations also designed as vapor barriers.

Are fire separations designed to be blast resistant

Location of Accommodations Module

Location of accommodations module-- exposure to blast, fire and smoke may be directly impacted by module location:

Is the LQ exposed to:

- smoke ingress
- thermal impact
- blast overpressures & shrapnel
- toxic vapor releases (hydrogen sulfide)
- dropped objects via cranes, helicopters, etc.
- ingress of flammable liquids (overhead aviation fuel supplies, deck tank overfill/rupture, etc.)

Is the LQ located near hydrocarbon processing piping and equipment on the same deck level: more than 50 feet away, between 50 and 25 feet, between 25 and 15 feet, less than 10 feet.

Is the distance from the LQ to nearest piece of hydrocarbon handling equipment item, storage tank or pipeline of significance:

Good: no closer than 75 feet

Fair: at least 25 feet

Poor: adjacent to or less than 25 feet from crew quarters.

Distance from LQ to nearest hydrocarbon fire threat, e.g., drill rig, wellbay, etc.: >40m, >30m, >20m, >10m, <10m

Location above any of hydrocarbon handling equipment item or pipeline of significance:

Is the LQ located above hydrocarbon processing piping and equipment installed on lower deck levels: directly above compressors, directly above production separators, directly above oil and gas risers, directly above pig traps, not directly above hydrocarbon handling piping and equipment.

Is the LQ location on opposite side of the platform from the wellbay†

Is the LQ located upwind of potential vapor release sources and smoke evolved from deck fires

Is the LQ provided with positive pressure ventilation system with air inlet located upwind of possible LOC sources

Is the LQ ventilation air supply located upwind of potential vapor release sources

Is the LQ located upwind of all other areas, including flare stack/boom, during conditions of prevailing winds: persistence = 100%, >75%, >50%, >25%

Location of refueling facilities for incoming aircraft:

are onboard aviation fuel storage facilities located above the LQ

Separation of Potential Fuel and Ignition Sources

Are topside areas generally in conformance with API RP 500, Section B.

Are potential ignition sources such as fired heaters, flares and other open flames devices safely located with respect to prevailing winds.

Has equipment handling lighter-than-air vapors been located on upper deck levels.

Has equipment handling heavier-than-air vapors been located on upper deck levels located above potential ignition sources.

† Location of the wellbay: recent innovative platform designs for deepwater operations, e.g., tension leg platforms (TLPs), have resulted in centrally located wellbays. This may result in increased fire exposure risk to the entire platform and especially the crew quarters

Are compressors handling lighter-than-air gases located in the open without potential overhead ignition sources.

Is the Power Generation and Utility (POGU) area (machinery area) separated from wellhead and process areas:

1) by vapor tight firewalls,

2) by firewalls with unsealed penetrations,

3) by at least 50 feet of freely ventilated space from large capacity/high pressure hydrocarbon handling equipment,

4) by at least 25 feet of freely ventilated space from moderate capacity/moderate pressure† hydrocarbon handling equipment,

5) by at least 15 feet of freely ventilated space from small capacity/low pressure† hydrocarbon handling equipment

Is the Fired Equipment Area located so as to pose minimal fire exposure risk to adjacent platform equipment areas and arranged so as to facilitate fire-fighting.

Is fired equipment grouped together is a single area on a production platform that is especially designed and located for firesafety.

If fired equipment is located in several different places on the platform, is the equipment designed as protected* fired equipment

Is the fired equipment area located upwind of the wellbay and process areas

Is the fired equipment area separated from wellhead and process areas:

1) by vapor tight firewalls,

2) by firewalls with unsealed penetrations,

3) by at least 50 feet of freely ventilated space from large capacity/high pressure† hydrocarbon handling equipment,

4) by at least 25 feet of freely ventilated space from moderate capacity/moderate pressure† hydrocarbon handling equipment,

5) by at least 15 feet of freely ventilated space from small capacity/low pressure† hydrocarbon handling equipment

Wellbay Arrangement

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* Protected fired vessels are designed in such a manner as was so as to eliminate the combustion air intake and exhaust stack and other hot surfaces as possible ignition sources. See API RP 500B

Are adjacent wellheads of flowing wells based on 2.5 meters (7.5 feet) of clear space between adjacent Christmas trees (not centerline to centerline).

Are wellheads arranged in a rectangular pattern

Are there more than 36 flowing production wells in a single contiguous grouping.

How many rows of wellheads in a single grouping: 5 or more, four, three, two.

What is the maximum number of wellheads in any one row: more than 12, more than 8, four or less.

For wellheads operating above 5000 psia is the number of wells in a single group no more than 8, 16, 24, more than 24.

For wellheads operating above 5000 psia is the number of rows of wellheads more than 1, 2, 3, 4.

Arrangement of Process Equipment

How congested are process areas:

Extremely congested -- little or no free access space for fire fighting activities; difficult for personnel to reach critical equipment isolation valves under normal (non-fire) operating conditions.

Moderately Congested -- high equipment density and multiple levels of pipe runs make equipment access difficult; little or no room for additional equipment or instrumentation.

Somewhat congested -- typical for offshore operations, but most equipment and isolations valves are readily accessible, adequate space for fire-fighting activities without unduly endangering personnel welfare.

Relatively Uncongested -- low piping and equipment densities, ample room for equipment and valve access and fire fighting activities.

How is deck drainage arranged:

Below Equipment: drip pans and catch basins/sumps are located directly below process equipment. Spilled liquids are collected directly below source of leakage.

Away From Equipment: sloped decks and/or drainage channels/curbs below process equipment is design to drain spilled liquids away from the underside of process equipment.

Is the shell-to-shell spacing between adjacent horizontal production separators at the closest tangential points less than 5 feet, 10 feet, 15 feet, more than 15 feet.

If free-standing atmospheric flammable liquid storage tanks located on the top deck:

are they located away from overhead lifting areas

are they located at least 50 feet away from the crews quarters

are they located at least 50 feet away from potential ignition sources

are the overfill/overflow lines piped to a safe location

Are pipeline scrapper launchers/receivers (pig traps) located in open, freely ventilated areas downwind of potential ignition sources, such as the flare.

Are crude oil metering and shipping facilities and Lease Automatic Custody Transfer (LACT) units located in open, freely ventilated areas downwind of potential ignition sources, such as the flare.

Does the locations of pipeline risers generally afford protection from physical damage -- both on the sea bottom from dragging anchors

Flares and Vent Stacks

Are flare stacks/booms located on the windward side of the deck

Do cantilevered booms extend off to one side of the leading (windward) edge of the platform.

Are elevated flares that are located directly upwind or above the upper deck are also a potential fire hazard from burning hydrocarbon liquids that could be expelled from the flare tip

Are elevated vent stacks located above the upper deck

Has liquid carryover via the flare or vent stack been a problem in the past

Air Intakes

Does the platform have mechanical ventilation and pressurization systems using ducted air

Are air intakes located in electrically unclassified areas

Are air intakes located in areas that could be enveloped by flammable vapor clouds or mists during abnormal conditions.

Are air intakes located in elevated positions on the upwind side (leeward) of the platform

Are air inlets located close to ventilation exhaust/discharge outlets

Are air inlets equipped with combustible gas sensors

Are air inlets equipped with duct-type smoke detectors

Are air inlets equipped with smoke dampers

What actions occur if gas is detected in an inlet duct:

- alarm only
- alarm and damper closure
- alarm and fan shutdown
- alarm, fan shutdown, and damper closure
- alarm, fan shutdown, damper closure, and de-energize all electrical equipment in ventilated/pressurized area
- discharge of fire suppressant/inerting agent

What actions occur if smoke is detected in an inlet duct:

- alarm only
- alarm and damper closure
- alarm and fan shutdown
- alarm, fan shutdown, and damper closure
- alarm, fan shutdown, damper closure, and de-energize all electrical equipment in ventilated/pressurized area
- discharge of fire suppressant/inerting agent

Emergency Shutdown Stations and Devices

Are remote emergency shutdown stations provided in accordance to OCS Order requirements

Are platform manual block (isolation) valves located in readily accessible positions that personnel can be reasonably expected to reach during an emergency condition

Are MOV panels for remotely actuated block valves located in safe areas or otherwise protected/shielded by firewalls/blast walls

How far are compressor shutdown stations located away from the associated compressors and drivers: at least 50 feet, between 25 and 50 feet, less than 25 feet, less than 10 feet.

How far are gas turbine shutdown and control panels located away from the machines: at least 50 feet, between 25 and 50 feet, less than 25 feet, less than 10 feet.

How far are crude oil pump shutdown panels located away from the pumps and drivers: at least 50 feet, between 25 and 50 feet, less than 25 feet, less than 10 feet.

Emergency Escape Capsules/Life-Craft Stations

What is the travel distance to the nearest emergency escape capsule loading stations from:

- the middle of the wellbay -- more than 250 feet, between 200 and 250 feet, between 150 and 100 feet, between 100 and 150 feet, less than 100 feet.
- the middle of the production separator area -- more than 250 feet, between 200 and 250 feet, between 150 and 100 feet, between 100 and 150 feet, less than 100 feet.
- the middle of the gas compression area -- more than 250 feet, between 200 and 250 feet, between 150 and 100 feet, between 100 and 150 feet, less than 100 feet.
- from the upper level of the crews quarters -- more than 250 feet, between 200 and 250 feet, between 150 and 100 feet, between 100 and 150 feet, less than 100 feet.

APPENDIX B5

OPERATIONAL/HUMAN FACTORS ASSESSMENT (OHFA) FACTORS

Appendix B5 focuses on "front-line" operational risk factors of platform activities that directly contribute to increased risk levels.

B5.1 MAINTENANCE AND REPAIR WORK (MARW)

Are any process critical operations† presently underway on the platform (identify):

- process critical - HIGH (pressure exceeds 500 psig)
- process critical - MODERATE (pressure above 100 but less than 500 psig)
- process critical - LOW (pressure 100 psig or less)
- no process critical operations ongoing

Estimate the anticipated frequency at which process critical operations (will) occur on the platform:

- continually -- on an ongoing basis for the next 12 months
- routinely -- on an continuing but periodic basis for the next 12 months
- occasionally -- on an interim basis for the next 12 months
- rarely -- only on an exceptional basis during the next 12 months

Are MARW activities routinely scheduled to occur during normal platform operations, e.g., without shut-down of production and drilling operations.

Estimate the anticipated percentage of process critical operations that (will) involve hotwork (welding, cutting, grinding, etc.) during the next 12 months:

- more than 90% of anticipated operations involve some type of hot work
- more than 75% of anticipated operations involve some type of hot work
- about 50% of anticipated operations involve some type of hot work
- less than 25% of anticipated operations involve some type of hot work

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† Process critical operations are considered to be those activities that involve vessel and/or line entry into hydrocarbon handling systems and equipment, e.g., operations posing an immediate risk of loss of containment. This includes all topsides process systems in which crude oil, natural gas, natural gas liquids (condensate) liquefied petroleum gases, and imported flammable liquids (methanol, glycol, aviation gasoline, etc.) that are either processed, treated or otherwise handled/stored. Major platform turnarounds during which time all well downhole safety valves are closed, and topsides processing equipment is shut-in, depressured, gas-freed, and inspected, are not considered within the scope of normal operations.

- nature of process critical operations over next 12 months unknown

Are process critical operations performed by contractors:

-- always, usually, sometimes, never

Are process critical operations always performed by the same contractor:

-- always, usually, sometimes, never

Is more than one MARW contractor ever present on the platform at the same time:

-- always, usually, sometimes, never

Are more than two contractors ever present on the platform at the same time:

-- always, usually, sometimes, never

Are more than three contractors ever present on the platform at the same time:

-- always, usually, sometimes, never

Are more than four contractors ever present on the platform at the same time:

-- always, usually, sometimes, never

Are workers performing process critical operations qualified to perform the work:

average offshore experience level of crew: more than 10 years, 5-10 years, 3-5 years, under 3 years.

trained in all safe work practices:

-- before start of job

-- within past 6 months

-- within past year, more than one year ago, do not know

Is more than one crew-shift required to complete the work

are shift changes arranged to overlap to allow for orderly turnover

are lock-out, tag-out procedures enforced

are work permit system procedures designed to ensure communication and monitoring of work progress during shift changes

are new members of crews introduced during the execution of a job

Are all contract works trained in emergency procedures

Are special emergency procedures necessary for the job at hand

has a what-if analysis been performed for the job

have all credible accident scenarios been identified

have all potential hazardous consequences been evaluated

Have crew members been instructed in special procedures

Is the required safety equipment readily available and in proper working condition

Is each work crew supervised by an experienced foreman

does the foreman have operating experience
is the foreman a contract employee
is the foreman accountable to the operational shift supervisor

Are non-process critical operations occurring on the platform
do these operations affect safety systems
have compensating measures been taken to mitigate system outages

Are platform personnel trained in emergency medical response procedures

B5..2 *MULTIPLE OPERATIONS ASSESSMENT (MULOPS)*

Anticipated frequency of multiple ongoing MARW concurrent/simultaneous activities of all types:
routinely more than one MARW activity occurring at any time
occasionally more than one MARW activity occurring at any time
rarely more than one MARW activity occurring at any time

Anticipated frequency of multiple ongoing MARW concurrent/simultaneous process critical activities:
routinely more than one process critical activity occurring at same time
occasionally more than one process critical activity occurring at same time

rarely more than one process critical activity occurring at any time

Anticipated maximum number of MARW projects occurring at any one time:
never more than five
never more than four
never more than three
never more than two
more than five

Do multiple MARW projects ever (often, sometimes, never) involve simultaneous hotwork and:
downhole operations (workover or wireline) -- O, S, N
pig launching/receiving operations-- O, S, N
line entry -- O, S, N
vessel entry -- O, S, N
tank entry -- O, S, N
system depressuring -- O, S, N
fuel transfer operations -- O, S, N

B5.3 *OPERATIONAL MANAGEMENT OF CHANGE (OPSMOC)*

Have changes been made to the platform process system that:

1) increase demands on platform operators
2) increase complexity of platform control
3) require more operator response time to react to upset conditions
4) all of the above
5) none of the above

Have temporary field modifications been made on an emergency basis that are still in use to sustain normal operations.

Have temporary changes been in place and operational for > 1 month, >3 months, >6 months, >12 months?

Have any temporary repairs/modifications/connections been made to the production system involving either containment or control of hydrocarbons, e.g., temporary piping bypasses, connections, valving, meters, equipment skid additions, compressors skids, etc.

Do any of the temporary changes involve installation of small diameter (<2 inch) screwed fittings/pipe in hydrocarbon service? <100 psi, <250 psi, <500 psi, <1000 psi?

Do any of the changes use plastic tubing, rubber hoses, or other materials of low melting point temperatures/combustible in hydrocarbon service.

If welding was involved for pipe joints, were the welds inspected and radiographed per ANSI B 31.3.

Were all materials used in the changes verified as correct for the services conditions encountered? Pressure rating, temperature rating, material selection for corrosion (alloys), erosion, etc.

Do any of the temporary repairs utilize compression type pipe clamps/couplings (such as made by "Dresser" or "Victaulic") or other similar fittings that use non-fire resistant elastomeric seals to maintain their integrity and prevent leakage.

Are platform operating procedures in agreement with actual operating requirements.

Does the production system function in more than one general mode of operation, e.g., two or more gas treating modes, or two or more liquid recovery modes

Are operators cross-trained in all operating modes on a routine basis

Have new startup/shutdown procedures been introduced within the past two years

Do platform instrument technicians routinely monitor rotating equipment for the purposes of diagnostic analysis and predictive time to failure calculations.

Is there a quality assurance (QA) program in effect on the platform that includes:

routinely monitoring changes in operating conditions of rotating equipment based on acoustical operating signatures, deviations from normal vibrational characteristics (axial and frame), temperature excursion trends, lubrication usage, etc.

Are operational inspection and monitoring frequencies determined from assigned equipment criticality categories that accounts for:

LOC potential based on pressure, flow rate, material being handled

Exposure potential to personnel and other equipment

Economic value -- loss of production and business interruption potential

Reliance placed on machine, provision of standby equipment, spares and spare parts, replacements, alternative production schemes

Ability of operators to respond and take timely corrective actions,

Consequence of failing to respond.

Are all CIHH rotating equipment items (Category 1) monitored at least once a week or are otherwise equipped with hard-wired probes/sensors that perform monitoring on a continuing basis.

Has the diagnostic analysis and predictive monitoring QA program proven effective

What is the rate of operator attrition on the platform:

High, above 15% on average

Moderate, between 5% and 10% on average

Low, less than 5% on average

What is the average experience level of platform operators:

High, above 10 years

Moderate, above 7 years

Low, less than 5 years

What is the average training level of platform operators:

well trained/highly qualified

adequately trained/ average qualifications

poorly trained/on the job training only

B5.4 *ASSESSMENT OF OPERATOR DEPENDENCE AND RESPONSE (OPSDAR)*

Is the control system functionally compatible with operator needs and capabilities.

- very flexible and compatible
- mostly compatible except in a very few instances
- limited compatibility -- operators must routinely improvise to maintain production levels
- incompatible -- operators cannot rely on control system to perform routine operating functions

Is it generally necessary for operators to incorporate improvised monitoring, measuring, and/or control techniques not presently addressed in operating procedures in order to keep the platform operating smoothly

Is necessary for operators to bypass, jumper, or otherwise defeat platform safety and shutdown signals and alarms in order to avoid frequent false alarms and spurious trips

Do platform operators and engineering technicians communicate openly and freely about needed improvements in system reliability

Have platform instrumentation and control systems in the past been:

- very reliable
- generally reliable, occasional failures
- generally unreliable, frequent failures
- unknown

Have platform safety systems in the past been:

- very reliable
- generally reliable, occasional failures
- generally unreliable, frequent failures
- unknown

How do platform operators assess their ability to respond to process upsets and to developing emergency conditions using the onboard control scheme:

- excellent -- usually ample response time to avoid shutdowns
- good -- occasional problems leading to unwanted shutdowns
- fair -- routine unwanted shutdowns due to demands placed on operators
- poor -- upsets generally result in too many demands placed on operating personnel to allow for prompt and correct response in most cases

Are operating personnel expected to manually fight fires

are they properly staffed, trained and equipped to do so

Has a new control systems been incorporated within the past two years, e.g., a distributed control system or other microprocessor based multiplex system.

Are all platform operators and shift supervisors fully trained in the new control system

Are platform blowdown system valves are automated or must operators manually

open them to depressure system piping;

Are platform water spray/deluge systems automatically actuated or must operators

manually open local control valves

In a fire emergency, are operators expected to fight fires with manually with hand-

hose lines, and other manual fire-fighting means

Is operator intervention required to shutdown and depressure CIHH process system

components:

local manual valve operation

local remote actuation

remote actuation from the control room or staging area

automatic fail-safe shutdown

B5.5 *OPERATIONAL HISTORY (OPHIST)*

General state of platform housekeeping:

excellent, good, fair, poor

Overall fire loss rate for past five years:

excellent, good, fair, poor, unknown

Overall fire loss rate compared to API industry averages:

above average, average, below average, unknown

LOC event frequency:

frequent small (unreportable) spills/releases

occasional small (unreportable) spills/releases

rarely experience an LOC event of any size

routinely incur reportable LOC events

Rank the five most important causes of platform fires reported over the past five years:

___ operator error
___ mechanical/material failure
___ improper procedure
___ improper supervision
___ failure to follow safe work practices
___ external event (lightning, mechanical impact, etc.)
___ inadequate inspection
___ inadequate maintenance
___ hot surface
___ internal combustion engines
___ corrosion
___ erosion
___ poor workmanship
___ hotwork/welding
___ electrical systems
___ smoking
___ failure to inert
___ improper startup
___ lack of job coordination
___ lack of job preplanning
___ lack of adequate training
___ lack of qualified personnel
___ control system failure
___ improper design
___ suspicious origin
___ unknown

Rank the three areas in which fires occur with greatest frequency:

___ wellbays
___ production area
___ gas treating
___ glycol reboiler
___ heater treaters
___ steam generators

___ gas compression
___ shipping and metering
___ power generation and utility area
___ pig launcher and receiving traps
___ flammable liquid storage area
___ bulk storage area
___ drilling area
___ quarters

APPENDIX B6

LIFESAFETY ASSESSMENT (LISA) FACTORS

B6.1 <u>Lifesafety Assessment of Accommodations (LISAA)</u>†

What is the capacity of the Living Quarters (LQ):

more than 50 beds

more than 30 beds

more than 20 beds

15 or less beds

Is the (LQ) intended to serve as a place of temporary safe refuge during fire emergencies

Is the LQ fabricated from noncombustible materials

Is the LQ more a multiple level structure:

one story

2 stories

3 stories

4 stories

more that 4 stories

Are all exterior walls of the LQ fire rated in accordance with a recognized fire test such as ASTM E-119 (IMO) or UL 1709:

one hour

two hour

three hour

four hour

not all walls fire rated

† "LISAA" is executed only if a platform is deemed to be manned, e.g., a platform on which people are routinely accommodated for more than twelve hours per day; further, FLAIM incorporates occupancy criteria to trigger LISSA based on whether the platform is actually and continuously occupied <u>by at least five persons</u>. If the platform is not deemed to be manned nor provided with living quarters (LQ), such as on a platform where the crew is rotated out each tower (work-shift) via helicopter or service vessel, FLAIM forgoes the LISAA component of the lifesafety assessment and evaluates the platforms lifesafety features, e.g., LISAP

Are only the exterior walls facing platform deck areas fire rated in accordance with a recognized fire test such as ASTM E-119 (IMO) or UL 1709:

one hour

two hour

four hour

walls not fire rated

Do these walls have windows facing the platform

Are windows protected by fire shutters

Are interior walls and floor/ceiling assemblies of the LQ fire rated in accordance with a recognized fire test such as ASTM E-119 (IMO) or UL 1709:

one hour

two hour

three hour

four hour

not fire rated

Are vertical openings between floors, e.g., stairwells, service chases, etc., enclosed by fire rated construction and equipped with self closing fire doors.

Is the roof assembly of the LQ a fire rated design

Is the underside of the LQ protected by fireproofing

Is the LQ support system a cantilevered structure outboard of platform legs:

If yes, are primary structural members fireproofed: 4 hr., 3 hr, 2 hr., 1 hr., 0 hr.

Is the LQ air handling system specifically designed for smoke control

Is the LQ air handling system specifically designed for combustible gas control

Is the LQ air handling system equipped with smoke detectors and smoke dampers designed to alarm, shut down supply fans and close inlet damper

Are all air intakes to the LQ provided with combustible gas detectors designed to alarm, shutdown fans, and close inlet dampers

Can ventilation air supply be shifted to alternative safe supply location in an emergency: manually

automatically

Is emergency power backup provided for smoke control/gas control systems

Is the LQ equipped with emergency lighting throughout

Is the emergency power supply for life support systems (including emergency lighting, communication system, etc.) protected from common cause failures†

Are interior areas of the LQ provided with smoke detectors

Is the LQ fully sprinklered in accordance with NFPA 13

Is the LQ provided with a fire alarm system

manual only

automatic and manual

automatic only

no fire alarm

Are mechanical/electrical rooms in the LQ equipped with automatic fire suppression systems

Are interior finishes of the LQ considered low flame spread materials in accordance with ASTM E-84, e.g., flame spread of 25 or less.

Is all wiring enclosed in conduits

Is grouped cabling with combustible jackets, such as PVC or neoprene, installed within the LQ in plenum spaces elsewhere

Are furnishings made of flexible polyurethane foam, such as sofas and chairs, used within the LQ

Do interior walls have textile wall coverings or matting made of combustible materials

Are interior ceilings comprised of acoustical tiles made from pressed vegetable fibers or other combustible materials

Is the galley equipped with an automatic range-top and cooking hood fire protection system in accordance with NFPA 17 or 17A

Does each level of the LQ have direct access to an exterior open air stairway or enclosed fire-resistive stairway that exits to a safe location.

Are there at least two emergency escape ways from the quarters structure connecting directly to life boat stations without exposing personnel to hazardous areas, e.g., from outboard sides of quarters structure.

Has there ever been a fatality in the LQ due to fire

Has there ever been a serious fire in the LQ

Is there a control room/radio room located in the LQ

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† For example, decoupled from common-cause failure events that could cause both loss of normal power and backup power, such as an explosion in the power generation module that damages cable trays carrying both power cables.

can vital platform control functions be initiated from the LQ
is there an emergency communication link in the LQ
are these areas provided with automatic fire detection and suppression

B6.2 Lifesafety Factors for Platform (LISAP)

In the event of a large fire, how difficult (very difficult, average, very easy) would you anticipate it would be to escape from the:

___ wellbay
___ production area
___ gas treating area
___ fired heater area
___ boiler room
___ gas compressor area
___ shipping and metering area
___ power generation and utility area
___ pig launcher and receiving traps
___ flammable liquid storage area
___ bulk storage area
___ drilling area
___ living quarters

Is the platform in compliance with all U.S. Coast Guard lifesafety regulations
Are support members for escape ways/catwalks fireproofed:
4 hr, 3 hr, 2 hr, 1 hr, 0 hr.
Are escape ways shielded from thermal/blast impact.
Are escape ways open or enclosed:
are enclosed escape ways provided with emergency lighting
Do all hazardous (process) areas on the platform have at least two egress routes that are in opposite directions and that are not exposed to the same hazards
Do all escape routes lead to life boat/evacuation stations.
Does the platform have a P/A system in addition to the USCG required fire alarms system

APPENDIX B7

RISK REDUCTION ASSESSMENT (RIRA) FACTORS

B7.1 ACTIVE FIRE PROTECTION & LIFE PROTECTION SYSTEMS

B7.1.1 Platform Firewater Systems

Is fire pump capacity based on probable maximum demand calculations

If yes, what is the probable maximum demand (PMD):

- less than 500 gpm
- between 500-1000 gpm
- between 1000-1500 gpm
- between 1500 and 2000 gpm
- between 2000 and 2500 gpm
- more than 2500 gpm

Is the probable maximum demand based on a fire in:

- the wellbay
- the production area
- the gas treating area
- the flammable liquid storage area
- the drilling area (blowout)
- other
- unknown

Are there more than one fire pump

Is more than one fire pump required to meet the PMD

If yes, are more than two fire pumps required to meet the PMD

Do all pumps required to meet the PMD have dedicated and separate standbys

Are the standby fire pumps located in the same fire zone as the primary fire pumps

Are the standby fire pumps driven by diesel engines

Are the primary fire pumps driven by diesel engines

Do standby fire pumps start automatically if primary pumps fail to start

Are all fire pumps test-run on a weekly basis

What is the general condition of the fire pumps

- excellent
- good

fair

poor

unknown

Is the fire water pumping and distribution system reliable

highly

usually

marginally

unreliable

unknown

Are fire pumps located in a safe area away from fire and blast exposures

Are fire pumps located in a separate fire rated enclosure

Are fire pumps protected by fire walls

Are fire pumps provided with automatic fire protection systems

Is the fire water distribution system arranged in a loop with isolation block valves between at least every five primary takeoffs

Is the fire water distribution system protected from damage caused by blasts

Are fire pumps U.L. listed and/or F.M. approved packages

Indicate number, size, location of fire pumps

Indicate types of pump and type of drivers

Do pumps automatically start on pressure drop?

Are fire pumps subject to common-cause failures

How long can engine driven pumps run without refueling

Are electric driven fire pumps on the emergency generator power bus

How long can the emergency generator run without refueling

Does the emergency generator remain operable during ESD's -- all levels

Does the emergency generator remain operable in event of gas release.

Do emergency generators automatically come on line whenever any electric fire pump starts or when the main generator is down.

Is the emergency generator(s) sized to handle the maximum inrush starting current of all electric fire pumps required to meet 100% of the fire demand.

Do fire pumps tie into different segmented section of fire main

Do fire pumps and drivers meet the requirements of NFPA 20

Are pump and pump motor matched such that under maximum pump discharge conditions the motor cannot be overloaded.

Is all fire pump motor cabling sufficiently fire resistant so as to remain operable for at least thirty minutes under direct flame impingement, including all feeder and control cables, e.g., mineral insulated (MI) cable.

Is stainless steel or other fire resistant materials used to secure motor power and control cables

Are fire pump motor controllers equipped with oversized thermal heaters.

Are power and control cables for each pump should be separately routed and protected from both blast and fire exposure.

Firewater Distribution Systems

Assessment of overall condition of firewater distribution system
excellent, good, fair, poor

Assessment of general reliability of firewater distribution system
excellent, good, fair, poor

Is the firewater system looped and provided with isolation valves to permit damaged sections to be isolated without loss of supply to other parts of the system

Is the firewater distribution system sized to deliver the PMD without exceeding a flow velocity of:
more that 15 feet/second
more than 20 feet/second
more than 25 feet/second
more than 30 feet/second
more than 40 feet/second

Is the firewater system provided with a pressure maintenance pump (jockey pump)

Do the main fire pumps tie into the fire main at different locations separated by isolation valves

What is the expected remaining life expectancy of the firewater system
less than 5 years
less than 10 years
less than 15 years
less than 20 years
unknown

Is the piping rated for a maximum working pressure that exceeds pump shutoff pressure

Are pressure relief valves provided in accordance with the requirements of NFPA 20

Is corrosion inhibitor injected into the system to control corrosion rates

Material specifications of fire main:

plain carbon steel

epoxy coated carbon steel

cement lined carbon steel

copper nickel alloy

carbon steel molybdenum alloy

Have flow tests have been performed on the firewater system to determine the system flow characteristics and the effective "C" factor.

What is the expected flow from the system at the hydraulically most remote location on the platform, e.g., normally the helideck, when flowing firewater at 100 psig residual pressure.

Have temporary repairs made to keep the system operational

When was the system last tested hydraulically

more than 10 years ago

more than 5 years ago

within the past 5 years

do not know

Is the firewater system used for any other purposes beside supplying firewater such as utility wash water or cooling service.

Firewater Hose Stations , Hydrants, and Monitors

Are all areas on the platform reachable by at least two hose streams from opposite directions using no more than 100 feet of hose.

Are ready-connected "live" hard rubber hose reels used for first-aid type response

Is the platform equipped with collapsible fire hose:

one and one-half inch

two inch

two and one-half inch

other

Is the platform equipped with fixed fire water monitors

Are monitors equipped with adjustable spray/straight stream nozzles

Are monitor locations generally free from obstructions

Are portable monitors provided for fire fighting

Are optical fire detectors used for: control room alarm only, local alarm, general alarm, alarm and shutdown, activation of fire suppression systems, other (specify)

Do optical fire detectors initiate closure of surface safety valves

Do optical fire detectors initiate closure of subsurface safety valves

Are electrical-powered heat detectors used on the platform

Are electrical-powered heat detectors located in: wellbays; process areas; utility areas, other (specify)

Are electrical-powered heat detectors considered: highly reliable, fairly reliable, marginally reliable, unreliable

Are smoke detectors used on the platform

Are smoke detectors located in the quarters, control rooms, electrical equipment rooms, other (specify)

Are smoke detectors considered: highly reliable, fairly reliable, marginally reliable, unreliable

Are heat or smoke detectors used for: control room alarm only, local alarm, general alarm, alarm and shutdown, activation of fire suppression systems, other (specify)

Combustible Gas Detection Systems

Are combustible gas detectors installed in all inadequately ventilated, enclosed classified areas, e.g., Class I Division 1 locations.

Have combustible gas detection systems been designed and installed in accordance with API RP 14C and RP 14F

Are combustible gas detection systems considered: highly reliable, fairly reliable, marginally reliable, unreliable

Are combustible gas detectors used for: control room alarm only, local alarm, general alarm, alarm and shutdown, activation of fire suppression systems, other (specify)

Do combustible gas detectors initiate closure of surface safety valves

Do combustible gas detectors initiate closure of subsurface safety valves

Do combustible gas detectors de-energize electrical equipment within the affected area

Do combustible gas detectors shut down engine/turbine-driven equipment within the affected area

Do combustible gas detectors control air handling and ventilation systems

Are all combustible gas sensors calibrated: once a month, once a quarter, once every six months, one a year, do not know

Alarm and Communication Systems

Is the platform provided with a general alarm system in accordance with U.S. Coast Guard Regulations

Are audible alarm signals sufficiently loud so as to be capable of being heard in all areas of the platform during normal operations

Are audible alarm signals distinct for each of the following conditions:

- Abandon Platform
- All-hands to emergency stations
- Fire -- General
- Fire -- Quarters
- High Gas Level Detected
- Low Gas Level Detected
- Other (specify)

Can the abandon platform alarm be initiated manually from emergency stations

Can the fire alarms be initiated from manual stations on the platform and in the quarters

Is there a public address (PA) system installed on the platform

Are platform personnel able to communicate with each other using:

- onboard intercom/telephone systems
- hand held UHF/VHF transceivers
- other (specify)

How would you assess the overall adequacy of platform alarms excellent, good, fair, poor

Is the platform provided with a dedicated radio room

Does the platform have a marine-band ship-to-shore radio link

Is there a telephone land-line service to shore

Have emergency radios been provided on all lifecraft

In the event of a major emergency, is there an automatic call-out message system

How would you assess the overall adequacy of platform emergency communication systems: excellent, good, fair, poor

Emergency Power and Lighting

Is the platform equipped with a UPS/EPS system of sufficient capacity to handle all critical electrical loads without interruption in the event of normal utility power loss

Does the platform have sufficient standby electrical generator capacity to handle all critical electrical loads, including electrically driven fire pumps that may be not have diesel engine-driven spares.

In the event of fire in the power generation area involving the main cable tray systems, would emergency power be disrupted on the platform

Are there any locations on the platform in which a fire could disrupt both normal utility and emergency/standby power sources to critical safety systems

Does the platform load-shedding scheme require any safety systems to be taken off-line in the event of a loss of normal utility power

How would you assess the overall reliability of the emergency/standby power systems on the platform: excellent, good, fair, poor

Is emergency lighting provided in accordance with API RP 14F.

In the event of fire in the power generation area involving the main cable tray systems, would emergency lighting be disrupted on the platform

Emergency Shutdown (ESD) Systems

Does the platform have a ESD system designed in accordance with API RP 14C

Does the ESD system have:

more than one level of shutdown
more than two levels of shutdown
more than three levels of shutdown
other (specify)

Has the ESD system been designed as a fail-safe (normally energized) system:

all levels of shutdown
only selected levels of shutdown (specify)

Are surface controlled subsurface safety valves:

manually operated only
manually operated and automatically operated by the fire detection systems
other (specify)

Is the ESD system interfaced to a platform depressuring system

Is the platform ESD system presently functioning as designed

Have field modifications been made to the ESD system in order to minimize incidents of unwanted shutdowns

Have such modifications bypasses some safety functions to facilitate operations

Have such modifications been reviewed in a HazOp

Is the platform ESD system consider to be:

very reliable, moderately reliable, not very reliable

Pressure Relief and Vapor Depressuring (Blowdown) Systems

Has the capacity of the platform pressure relief system been reviewed:

within the past five years

within the past one year

more than five years ago

not reviewed since platform was built (indicate years)

Is the adequacy of the platform relief system capacity known

Are all platform pressure relief valves routinely tested and inspected

Has new/additional process equipment been added to production systems since the original design and connected to the relief header.

Is the relief header capacity adequate for the present as-built operating conditions

Is the header size based on balanced bellows-type relief valves and, if yes, have all relief valves been audited to meet this requirement

Are adequate liquid knock-out (scrubbing) facilities provide to prevent liquid carryover

Has the relief header been designed for the maximum operating temperatures and thermal stresses possible during credible fire scenarios

Does the platform have a vapor depressuring system

Can all high pressure gas systems on the platform be depressured within 15 minutes of system actuation

Is the depressuring system automatically actuated in the event of

fire in the wellbay

fire in the separator area

fire in the gas compression area

other (specify)

Is the vapor depressuring system sized to handle the maximum possible fluid flow from the largest single fire zone on the platform based on actual area of the module

Are liquid scrubbing provisions adequate to prevent liquid carryover to vent and flare stacks under maximum flow conditions

Liquid Spill Control Provisions

Are platform drainage systems of sufficient capacity to remove both spilled liquids and firewater discharge for credible LOC and fire scenarios

Will deck drains and curbs confine burning liquids to within designated fire zones

Are deck drains provided with gas seals/traps to prevent vapor migration to other areas

Are close-ended sumps/piles provided with level indicators and alarms

Are platform drain systems well maintained and fully functional

Thermal Robustness and Passive Fire Protection Systems

Has the platform structural design been analyzed to assess member criticality, e.g., determine if the failure of any single structural deck member, or adjacent group of members (subject to mutual fire exposure) could cause localized or progressive collapse

Are critical structural members in the wellbay provided with fireproofing

- no
- no -- but protected with water spray/deluge systems
- yes -- one hour hydrocarbon fire
  - two hour hydrocarbon fire
  - more than two hour hydrocarbon fire
  - one hour cellulosic fire
  - two hour cellulosic fire
  - more than two hour cellulosic fire

Are primary critical structural members in process areas provided with fireproofing

- no
- no -- but protected with water spray/deluge systems
- yes -- one hour hydrocarbon fire
  - two hour hydrocarbon fire
  - more than two hour hydrocarbon fire
  - one hour cellulosic fire
  - two hour cellulosic fire
  - more than two hour cellulosic fire

Have secondary structural steel support members in critical services been fireproofed, e.g., cantilever supports for accommodations structures, major equipment items, egress ways, life saving systems,

Is the platform provided with firewalls

to separate the well bay from adjacent areas

to separate the production separators from adjacent areas

to separate the gas compression area from adjacent areas

to separate the gas treating area from adjacent areas

to separate the fired heater hears from adjacent areas

Other firewall locations (specify)

Are firewalls designed to USCG/SOLAS fire test standard ratings:

A0, A30, A60, A120, H0, H30, H60, H120, other

Are personnel access ways located in firewalls

Are such assess ways equipped with rated fire doors equipped with door closers

Are pipe and cable tray penetrations sealed with fire resistive sealing compounds/systems that are rated to the same degree as the firewall

Design for Explosion Protection

Have provisions for blast resistance have been incorporated into the structural design of high risk platform areas

Have firewalls been designed to resist blast effects

Are fire resistive coatings capable of sustaining the same degree of flexure that structural plate walls could incur without spalling

If not, have firewalls been stiffened to prevent failure of protective coatings

Are oil and gas piping systems that penetrate bulkhead walls adequate braced in a latitudinal direction to prevent shear failures from excessive displacement

Are enclosed oil and gas handling areas provided with adequate ventilation

Are ventilation rates sufficient to prevent the accumulation of vapors within enclosed areas under normal operating conditions.

Are process areas maintained at a negative pressure relative to enclosed areas containing ignition sources

Are positive pressure ventilation systems installed in accordance with NFPA 496.

Is the platform equipped with explosion relief (venting) systems

Are explosion vents designed to meet the criteria of NFPA 68

Are explosion venting panels positioned so as to avoid personnel access ways and the means of egress

Are platform fire pumps and their power sources protected from blast effects

Is the living quarters protected from blast damage and projectiles

Have platform risers been designed to account for blast effects and induced displacements

Has the platform ever experienced a loss due to explosion

Were any changes made to the platform design as a result of past explosions; specify

APPENDIX B8

SAFETY MANAGEMENT SYSTEM ASSESSMENT (SAMSA) FACTORS

B8.1 *MANAGEMENT SYSTEMS SAFETY CULTURE ASSESSMENT (SCULA)*

B8.1.1 Organizational Responsibility & Resources

How many production platforms on the U.S. OCS does the operator currently maintain

Does the operator maintain a staff of risk management and loss prevention/safety experts

Is the safety staff comprised of experienced engineers and operating personnel with backgrounds in risk assessment and fire protection

Is there a Manager of Loss Prevention Engineering/Process Safety or equal on the staff

Does the Manager of Loss Prevention Engineering/Process Safety have direct authority to order the shutdown of a platform

Are loss prevention surveys/audits of all platforms routinely conducted

Are loss prevention surveys/audits performs by independent third party experts

Are contract labor and outside consultants being used to provide safety services

Is contract labor properly supervised to ensure compliance with company safety policies?

Are high hazard activities controlled by formal safety systems

Are platform modifications subject to a HazOp before initiated

Percentage of operating budget allocated to:

-maintenance

-inspection & testing

- loss prevention

- training

B8.1.2 Company Policies and Procedures (POLPRO)

Are company safety goals, objectives, programs, and practices defined in a written policy statement and procedure

Are written, up-to-date operating instructions maintained for all topside systems and process components, including

startup procedures

normal and temporary operations,

emergency operations including emergency shutdowns (for each level of shutdown)

black-start restarts from complete shutdowns of all platform operations and power sources

Are individual startup/shutdown and operating instructions for pumps, compressors, fired heaters, etc., explicit for the machine in its "as-built" (as-installed) condition

Is a written Safe Work Practices (SWP) Manual available the covers all safe work practices and policies, including:

a Permit to Work procedure

line and vessel opening/entry operations

lockout and tagout procedures

confined space entry

hot work and cutting operations

inerting and purging practices

heavy lifts and crane operations

sampling and sample connections

opening of drains and vents,

use of personal protective clothing and gear

Are detailed emergency response and contingency plans maintained up-to-date and "evergreen" based on feedback and critiques of hypothetical drills

Are detailed records/documentation being collected in the following areas:

Maintenance

As-built engineering designs (piping, electrical, etc.)

Corrosion records

Operational procedures

Training records

Personnel records (licensing, medical, etc.)

Inspection & tests

Emergency procedures

Accidents & near misses

B8.1.3 Accountability & Auditing (ACAU)

Is a Safety Assurance Program (SAP) in effect on the platform

Does the Safety Assurance Program include written instructions/requirements for detailed auditing of vital safety program elements

Does the SAP cover both design and operating considerations

How often are Process Safety/Loss Prevention Audits performed on the platform: Quarterly, Semi-Annually, Annually, Biannually, Other (specify)

Are the results of audits formulated into specific recommendations and reviewed by management/operating committees

Are audit recommendations prioritized and scheduled for implementation

Are uncompleted recommendations tracked by management until their completion

Are audits performed by teams comprised by both operating and engineering personnel

Are platform auditors experienced personnel knowledgeable about platform safety systems and safe operating practices

Are SAP team members formally trained in conducting safety audits

Are SAP team members informed about the accident history of the platform and similarly platforms in the region

Do SAP team members use a check list of "lessons-learn" from past accidents and near misses in order to identify similar potential problems during their reviews

Is the information collected in the audits communicated back to the platform operators

Have safety audits had any effect on improving the safety culture of the organization: significant effect; moderate effect, little effect, no noticeable effect

How would you rate the overall effectiveness of the SAP: excellent, good, fair, poor, do not have a SAP or equal program in effect

B8.2 *FIRE PREPAREDNESS ASSESSMENT (FIPA)*

Have fire fighting response plans been developed for credible fire scenarios the can be reasonably anticipated on the platform

Are the response plans sufficiently detailed so as to identify each persons responsibilities and duties required to fight any given fire

Have the assigned fire fighting duties also considered other operating demands that may be placed on personnel including, operations and shutdown functions, communications, evacuation and lifecraft manning, etc.

Are fire fighters expected to operate manual block valves in order to isolate critical sections of piping or process equipment?

Have the assigned fire fighting duties been sequentially analyzed for time-demand conflicts with other duties

Does the platform have sufficient personnel onboard to perform the required fire fighting duties

Do platform personnel have a clear understanding of their assigned duties in the event of a fire, and how these duties may change for different fire scenarios

Are there any individual roles that are so vital that, if unfulfilled, could result in an immediate lifesafety threat to other personnel.

Have vitally important fire fighting roles been made known to those individuals assigned with those duties

In the event of injury to any of these vitally important fire fighters, are backup personnel available and trained to assume their duties

Could any of the vitally important duties be eliminated by means of installing fire suppression systems or automatic control equipment

Are all platform personnel that are assigned fire fighting duties fully trained in accordance with OCS Orders

Are all platform personnel that are assigned fire fighting duties fully trained to the specific requirements of their assigned tasks

Does the platform emergency contingency/response plans call for the establishment of a emergency command center on the platform

Are platform fire fighters trained in emergency contingency command center protocol

How often do platform personnel participate in hypothetical fire training exercises on the platform: at least once each month, 3 months, 6 months, one year, other (specify)

Do assigned platform fire fighters participate in oil and gas fire school training: at least annually, biannually, more than biannually

Are platform fire fighters made responsible for the inspection and maintenance of fire fighting equipment

Are platform fire fighters cross trained in safe shutdown procedures

Are platform fire fighters trained in first-aid

Has proper personnel protective and safety equipment been provided for all fire crew members

- turnout gear
- Nomex clothing
- SCBA (air packs)
- first-aid kits
- rescue lines and equipment
- portable ventilation blowers for smoke removal
- portable gas detection equipment (sniffers)

B8.3 Safety Training Assessment (SATA)

Have all platform operators been trained to API RP T-2, *Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work with Anti-Pollution Safety Devices* in accordance with OCS requirements

Have all platform operators been trained to API RP T-4, *Recommended Practice for Training of Offshore Personnel in Non-operating Emergencies*

Have all platform operators been trained to API RP T-6, *Recommended Practice for Training and Qualification of Personnel in Well Control Equipment and Techniques for Completion and Workover Operations on Offshore Locations.*

Have platform crane operators been trained to API RP 2D, *Recommended Practice for Operation and Maintenance of Offshore Cranes*

Are all platform personnel routinely trained in emergency evacuation procedures

Are all platform personnel routinely trained in safe work practices

How would you rate the overall level of training provided to platform personnel: excellent, good, fair, poor, do not know

B8.4 *MANAGEMENT OF CHANGE MANAGEMENT PROGRAM* (MOCMAP)

Has platform management established a formal MOC management program

Does the MOC program address both changes in the facility and in personnel

Does the MOC program establish written procedures that address how to identify and control hazards that may arise from changes in design and operations

Does the MOC program address procedures for managing information and maintaining its accuracy and completeness

Do MOC procedures require a formal analysis of safety, health, and environmental considerations involved in the proposed change based on a recognized hazards analysis procedures such as a Hazard and Operability Study (HazOp)

Does the MOC procedure include instructions and requirements for performing a HazOp or equivalent review

Does the MOC procedure address how to communicate the proposed change and its implications to all personnel affected in the organization

Does the MOC procedure communicate the requisite levels of management approval needed to proceed with implementing the change

Have the temporary changes been made on the platform that have not been subject to a HazOp review or equal.

Does the MOC procedure require a formal analysis of the present status of the platform if such as review has not been made before

Have the temporary changes been field-run without the benefit of full engineering review and approval due to their urgency?

Are the following areas being reviewed and updated with regard to management of change:

-operating procedure

-safe work practices

-training program

-maintenance practices

-emergency procedures

Has the proposed change and consequences of that change been communicated to the appropriate personnel in writing

Is this information documented and retrievable

Have revisions been made to the safety and environmental information systems (material safety data sheets (MSDS), new chemicals, etc.)?

Has the proper procedure been established at the management level to authorize/initiate changes?

Has contractor provided written safety policies endorsed by the contractor's top management?

Has contractor provided a statement of commitment to comply with applicable safety regulations and provisions discussed in API RP 750?

Does the contractor have OSHA defined recordable injury and illness experience?

Has the contractor provided Experience Modification Rates (EMR) for Workman's Compensation Insurance for the previous three years?

Has the contractor provided an outline of their initial employee safety information program?

Is there evidence of disciplinary action procedures dealing with safety related infractions?

Is there a description of the contractors various safety programs:

-accident investigation procedures

-how safety inspections are performed

-safety meetings

-safety incentive programs

-substance abuse programs.

Has each contractor employee received a description of the safety training used by the contractor?

End of Appendix B

APPENDIX C

EXAMPLE PLATFORM

Appendix C illustrates the application of FLAIM on a hypothetical offshore production platform (Example Platform) as described below.

Platform Description

Example Platform is a steel template-type eight leg jacket structure located approximately 25 kilometers offshore in about 25 meters of water on the U.S. outer continental shelf. It was designed and constructed in the early 1980's, based on a limited design life of 10 years for both structure and topsides processing systems. It is now approximately two years beyond its initial design life criteria, and expected to be kept in operation for approximately another ten years based on current enhanced oil recovery (EOR) predictions. The platform is being structurally requalified independently of a topsides risk assessment in which FLAIM has been selected to perform an initial screening of fire and life safety.

The topsides production facilities were initially designed to handle a maximum of 15,000 BPD of crude oil and 48 mmscfd of associated gas, with produced water estimated to average 8500 BPD. Primary phase separation occurs onboard, with gas production being used for gas lift and utility fuel gas supply. Excessive gas is still being flared; the platform does not have a gas riser nor gas pipeline to shore. Crude oil and natural gas liquids are commingled and shipped to shore via a 20 inch subsea liquids pipeline and riser. A pipeline pig launcher/receiver is located below the lower deck level on an access platform. Produced water is treated and injected back into the reservoir for pressure maintenance. The platform is presently producing 18,000 BPD of 35 API gravity sweet crude, 800 BPD of natural gas liquids, 20,000 BPD of produced water, and 20 mmscfd of natural gas. The hydrogen sulfide content of the produced gas was initially negligible, but has risen slightly over the production life of the reservoir and is now slightly sour.

Topsides are arranged in two levels of unenclosed decks or equal areas, typical for warm water GOM designs for the era. Each deck measures approximately 25 meters wide by 40 meters in length. The lift weight of each deck section was approximately 500 tons. The wellbay is located on the lower deck level at the south end of the structure. The wellhead area and the first bay of the deck inboard from the wellbays have been kept to a maximum width of approximately 10 meters in order to provide access for a slot type jack-up drilling rig. The platform jacket and deck design was not designed to support an onboard workover rig.

A total of 12 production wells have been drilled from the platform as originally planned. Of these, three have been converted to water injection wells and one to a gas injection well. Spacing is arranged in three by three configuration, as controlled by the seafloor template, with each well conductor on a center to center spacing of approximately 2.25 meters. The conductors are free-standing from the mudline (@ - 25 meters) to elevation +4.0 meters at which point conductor guides provide lateral support. The conductors continue from this elevation to the second deck level at approximately +17 meters above sea level where they enter the cantilevered well area. The conductors are 20 inch in diameter with a one inch wall thickness.

Production facilities consist of three stages of crude oil separation. The first stage separator operates at 250 psia and 200 °F; the second stage separator operates at 125 psia and 180°F; and the third stage separator operates at 20 psia and 150°F. The third stage separator also serves as a surge vessel for the stabilized crude shipping pumps. All separators are fully equipped and instrumented to perform three phase separation. The first and second stage separators are equipped with remotely operated depressuring valves that discharge to high and intermediate pressure relief headers that vent directly to atmosphere. A gas fired packaged heater is used to increase the oil temperature to the first stage separator to enhance vapor separation. The heater is a indirect fired unit utilizing heat transfer medium to heat the production stream via a shell and tube heat exchanger. Heat is also supplied to the glycol regenerator via this system.

Produced gas is sent to a J-T flash drum where condensable natural gas liquids are recovered for subsequent shipping to shore with the crude. Produced gas is dehydrated in a ethylene glycol contractor for dew point control before going to gas compression. Two gas turbine driven centrifugal compressors boost gas pressure to 1000 psia for reinjection and gas lift. A gas lift manifold complete with meters and chokes is provided to facilitate injection of gas to the respective wellheads. The gas lift control chokes can be controlled from the control room.

Most of the produced water is obtained from the first stage separator and is fed directly to a oily water treatment unit, as is water from the second and third stage separators. Two 100% capacity corrugated plate interceptors (CPI) are provided to separate solids as a sludge from produced water. Oil is coalesced and skimmed off as an overflow steam. Treated water from the CPI flows to the gas flotation unit for further oil removal. Flotation cells remove oil formed as a froth by the action of motor driven agitators. The froth is then recycled to the CPI for processing. Sand and sludge deposits are manually washed and drained from individual floatation cells without overall interruption to operations or reduction of throughput.

Collected oil spillage on decks flows by gravity to a sump tank located below the wellhead deck where pumps can be manually started on high level indication to transfer slop oil back to the first stage separator. Three inch curbing and drip pans are provided around packaged equipment to prevent spills from reaching open grating deck areas and the sea.

Crude oil and natural gas liquids are shipped to shore by two 150 HP electric motor-driven centrifugal pumps. Each pump is rated for 1000 BPH at a discharge pressure of 275 psig. The third stage separator level controller modulates the shipping pump discharge rate. The pumps will automatically shut down on separator low-low liquid level. Controls are local pneumatic, and include high and low level alarms fed to the main control panel.

Power is provided by two gas engine driven generator sets, each rated at 100% of the platform maximum electrical load. Both units are normally run at 50% capacity to ensure maximum power reliability in the event that one unit suddenly fails. Power is generated at 480/240 volts, three phase, four wire, 60 Hz. An emergency diesel generator is also provided, rated at 150 kW, together with a UPS system for emergency power backup to critical alarms and controls. All process areas on the platform have been electrically classified as Class I, Division 2, Group D except for deck sumps which are classified as Division 1. The upper deck is mostly unclassified except for the glycol dehydrator and regenerator area which is classified as Division 2.

Process control and monitoring is designed for local pneumatic operation. Critical flow rates, pressures, temperatures, liquid levels, pump status, alarms and shutdowns are locally monitored to ensure safe and efficient production. Startup and shutdown of individual package units is performed locally and in general only one common trouble alarm and common shutdown alarm signal is sent to the central control panel in the control room. The central annunciator panel has first-out indication capability for all emergency shutdown systems (ESD) trips. Other process information is also monitored from the central panel, but this was done on a very limited basis in an effort to keep capital costs to a minimum.

Well control is comprised of a system of pneumatic/hydraulic control panels. A master panel provides hydraulic pressure for operating the subsurface down-hole safety valves and for controlling the air supply for operating the surface safety valves, e.g., the middle master and wing valves on the Christmas Trees. Fusible plug pneumatic loops are provided throughout the wellhead and production areas. Loss of control line pressure in the loop will result in a platform shutdown, closing both surface and subsurface valves. A platform ESD can also be manually initiated via ESD stations positioned at several places at both deck levels.

Each wellhead is equipped with a manual Willis choke valve and tubing pressure and temperature indicators. The flow of produced fluids to the production separators is controlled by manually setting the Willis chokes on each producing well as well as the gas lift rate to each well. Flow within the production train is maintained by level controllers. Vessel pressure is maintained by a pressure control valve on the overhead line via a PIC. High/Low level and pressure overrides are provided to actuate an ESD shutdown in the event of a process upset. Depressuring can be remotely initiated via MOVs; however, these are normally deenergized valves and require preservation of circuit and power supply integrity in order to operate. Manual bypass valves at each of the first and second stage separators and the two gas compressors have been provided.

No structural fireproofing or passive fire protection for critical instrument, control and power circuits is provided. Unprotected steel plate bulkhead walls (designated as firewalls) separate the well bay area and the production and gas compression areas, all are located on the lower level of the platform. Thermal robustness of the structural design is minimal. All main compression chords and columns were designed for a kl/r of 80, and secondary braces for a kl/r of 120. D/t ratios of 80 for the main legs and between 20 and 1900/Fy for main braces were used. Platform design was predicated on a 50 year return storm, using 1.33 times API RP 2A allowable value (1980). Seismic loading was not considered; structural design was controlled by storm loading.

The topsides is equipped with a 20 bed crew quarters, complete with galley and mess facilities, and a helideck designed for a Bell 412 chopper or equal (impact deck loading of 22,400 lbs.) Helicopter refueling facilities are provided above the quarters, below the helideck. Aviation fuel is stored in a 1000 barrel atmospheric storage tank on the main deck adjacent to the crew quarters. One small boat landing is provided on the north side of the jacket opposite the wellbay. Bulk supplies, water, aviation fuel, and standby fuel for the gas turbines is supplied via services vessels.

Material handling facilities on the upper deck and the lower deck area consists of a pedestal marine crane, monorails, hoists, and a jib crane. Conductors and riser are protected from impact by marine vessels by a three dimensional truss network of tubular steel design. This protection frame extends from elevation -2.0 meters below sea level to +4.0 meters above sea level. However, one conductor casing was moderately dented during an off loading operation involving the platform's pedestal crane. One fatality was reported during the past five years due to improper rigging during a heavy lift. This incident also caused two fuel gas lines to rupture, however there was no ignition prior to shutting-in the fuel system.

The platform is equipped with a firewater system consisting of an eight inch water distribution main and two 500 gpm diesel engine driven fire pumps located on the lower deck near the gas compression area. Water is supplied to hose stations and hydrants located around the perimeter of the deck areas. There are no fixed water spray systems, foam systems or fixed fire detection systems onboard other than the fusible plug ESD system and a heat detection system in the quarters. Dry chemical fire extinguishers are located in all process areas. The gas compression area is also equipped with combustible gas detection sensors; however, reliability of the system has been a problem and the system has been bypassed.

All steel surfaces above the splash zone (about +3 meters) were initially painted with a urethane/epoxy system preceded by zinc primer. However, the paint system has not been well maintained and visible signs of external corrosion are prevalent. Cathodic protection was provided for all submerged jacket members; however, the sacrificial anodes have not been maintained. A 1/4 inch corrosion allowance was provided in the splash zone for all jacket members, pump casings, disposal sumps, risers, conductors protection framing, walkways, and boat landing supports. Advanced corrosion in several areas indicate that this allowance may be exceeded. The state of corrosion beneath insulated process equipment is indeterminate. The is no crack detection program enforce on the platform.

The overall platform safety record has been average; however, record keeping on near misses (if maintained) would show an ever increasing number of incidents over the past four years. The demands on the operating crew to maintain production levels has increased due to the ever growing number of temporary fixes needed to prevent shutdowns. The number of process system leaks has not been tracked, but their frequency has steadily risen largely due to failure of small piping connections. Two surface safety valves have had problems and have been put in bypass until the next scheduled turnaround in approximately 14 months. Preventative maintenance has also been cut back due to a lack of manpower and budget limitations.

Due to increasing budgetary pressures, management has deemed it necessary to cut funding for routine inspection and maintenance activities, as well as in areas of training and other non-essential production activities. The inspection and maintenance crew has also been downsized, and platform operators have been required to work longer shifts and longer rotations. The net result has been a steady decrease in the crew's morale, and many of the more experienced crew members have elected to leave their jobs of opportunities elsewhere. Management has in most cases elected not to seek replacement personnel except in those instances where present staffing levels could not meet operating demands. In those instances, less experienced personnel that could be hired at lower wage rates were selected as replacements. As a consequence, the makeup of the operating crew has changed considerably over the past five years, although, on the surface, platform operations have continued on routinely. Consequently, management is currently looking for additional ways of further optimizing operating and maintenance costs that may have been overlooked in the past.

Assessment Of Fire And Life Safety Using FLAIM

The FLAIM assessment process begins as described by the steps listed in the user instructions given in Appendix A. It was recognized by management that FLAIM created a unique opportunity for improving the overall risk management program and policies within the company as well as providing a power tool for their execution. Based on experience from past Hazard and Operability studies (HazOps), management elected to bring together several senior-level employees with backgrounds in platform operations, maintenance &

inspection, engineering, and operational safety in order to establish a consensus for FLAIM's initial calibration and application.

The group's tasks are 1) to reach a consensus on the level of detail warranted in the screening process (e.g., select an appropriate Tier level for the review), 2) select the appropriate questions relevant to the platform under consideration, 3) determine if any questions have a higher or lower relative importance (weighting value), and 4) for those questions in which a numerical range is involved, assign a value range to each answer selection provided in the question. Once this has been accomplished, the actual assessment process may be completed either onboard the platform or in the field office by one or more persons knowledgeable about platform design and operations.

Calibrating the Worksheets

The session begins with the meeting facilitator loading and opening the FLAIM software package. The first window that appears after FLAIM is started is "Platform Identification Information." In this example, the user enters "Example Platform," its location (GOM), block (ANY) and lease numbers, etc., and clicks OKAY. The next window will appear asking whether a new platform assessment or modification of an existing platform assessment is to be performed. The example is based on a first-time assessment and the user clicks on "NEW."

When the user reaches the "Fire and Life Safety Assessments Options" menu after inputting the preliminary information asked for, eight assessment choices are available corresponding to each assessment modules as described in FLAIM. These are:

- General Factors Assessment (GEFA)
- Loss of Containment Assessment (LOCA)
- Vulnerability to Escalation Assessment (VESA)
- Layout and Configuration Assessment (LACA)
- Operations and Human Factors Assessment (OHFA)
- Risk Reduction Measures Assessment (RIRA)
- Life Safety Assessment (LISA)
- Safety Management Systems Assessment (SAMSA)

For a new assessment, the user begins with General Factors Assessment (GEFA), and then continues down the list until such time that all information has been inputted into each assessment module. In this example, FLAIM's General Factors Assessment Module is illustrated and the GEFA risk index is determined. In an actual application, FLAIM calculates the overall fire and life safety index once all of the appropriate assessment modules have been completed and also determines the difference any changes may make by calculating a differential risk index. A complete example is included on the floppy disk.

After selecting the General Factors Assessment button on the "Fire and Life Safety Assessments Options" menu, another window appears indicating that the FLAIM assessment process is ready to begin. Selecting OKAY brings up the GEFA Question Worksheet. In accordance with the instructions in Appendix A, the user(s) now selects some or all of the questions listed in the work sheet by assigning an appropriate Tier level value as described in Appendix A. The user may also decide to modify existing questions or add new questions in order to customize the assessment process to conform with platform conditions and needs.

In this Appendix, a Tier 1 screening assessment is illustrated for the first section of the General Factors worksheet. A completed Tier 1 evaluation including all FLAIM assessment modules is included on the enclosed 3-1/2" micro floppy disk in the file folder labeled EXAMPLE PLATFORM. This will allow first time users to examine individual questions selected within each assessment module for Tier 1 screening and review how each question was weighted, assigned value ranges when appropriate, and how changing any parameter affects the individual and overall risk indices.

For this hypothetical example, the users have determined that those questions indicated by a 1 (see Figure C-1) should be included in a Tier 1 assessment; these questions were selected by clicking on the gray button labeled "Select Tier Level" and then double clicking in the white (empty) box directly to the left of the question desired, e.g., in the first column of the worksheet. As explained in Appendix A, red-level questions (as indicated by an "*" in the first column of the worksheet and by red shading on a color monitor) are automatically entered into the assessment due to their perceived importance to platform safety. The user is free to add, delete, or modify both red-level and non red-level questions as deemed appropriate for the class of platforms being evaluated.

The General Factors Question worksheet contains approximately 142 questions from which the users may select, modify or add to in order to develop the most relevant information appropriate for the particular platform under consideration. After question selection via Tier level assignment has been complete, the facilitator copies the selected questions to the FLAIM Assessment worksheet by clicking on the green button labeled "Copy Questions to Assessment Sheet."

GENERAL FACTORS ASSESSMENT QUESTION WORKSHEET

Return to FLAIM Assessment Menu (Red)

Select Tier Level (Gray)

Copy Questions to Assessment Sheet (Green)

GOTO Assessment Sheet (Yellow)

Tier	Questions
	1. PLATFORM DESCRIPTION
	1.1 Physical
*	Platform age yrs
*	Last complete turnaround months
*	Have major modifications been performed to process system subsequent to first oil initial startup ? Y/N
	Are there special requirements for materials of construction for piping and equipment? Y/N
1	Age of production trains average yrs
1	Age of gas compression equipment average yrs
1	Age of combustion gas turbines average yrs
1	Deck area sq ft
1	Number of drilling rigs
*	Active development drilling taking place? Y/N
1	Average persistence of workover operations? months
1	Number of deck levels
	Number of jacket legs
	Water depth ft
	Distance from shore miles
	Approximate response time for emergency service vessel assistance min
	Deck height above sea level ft
*	Number of contract personnel routinely onboard
1	Size of living quarter number of beds
1	Helideck provided? Y/N
	How many production platforms on the U.S. OCS does the operator currently maintain?

Figure C-1
Sample of FLAIM General Factors Question Worksheet
(all questions not shown)

Upon completion of the copying process, FLAIM returns the user to Question worksheet. It is then the users option to either:

(1) select further questions of a different Tier level to copy to the assessment sheet,

(2) to return to the FLAIM assessment menu (by clicking on the red button entitled "Return to FLAIM Assessment Menu") in order to select a different category of questions, or to

(3) activate the assessment sheet to begin the assessment process by clicking on the yellow button entitled "GOTO Assessment Sheet."

In this example, the users have determined to perform a Tier 1 level review of General Factors, and therefore select option (3) by clicking on the yellow button entitled "GOTO Assessment Sheet" to begin the assessment process.

The next step in the assessment process is to assign weights to "red-level" questions and range limits for numerical questions (see Section 11.1.3 and Section 11.3.1). The column to the right of the FLAIM questions are where the user inputs the value, grade, or binary input to the question. For all numerical questions selected, and all red-level questions, the user completes the assessment worksheet setup process by inputting range values and/or weight values for each question showing either a red or yellow box to the right of the selected question, e.g., in Column C. This is done by clicking on the red button labeled "Assign Question Weights/Value Ranges."

Red boxes indicated require the user(s) to make an independent judgment on the relative value of the particular risk factor which has been identified as a red level question. If the question is judged to be of no greater importance than any other Tier 1 level question, then a weighting value of 5 is assigned, whereas if the question is deemed to be, for example, twice as important, a value of 10 would be assigned. Once the red-level questions have been weighted, the color of the input box changes from red to yellow (in the case where the question is numerical in nature and requires a value range assignment) or white (in the case where the question is binary in nature).

In this example, after the facilitator clicked on the red button labeled "Assign Question Weights/Value Ranges, the review group addressed the first question which asks about platform age -- a red-level question. Double clicking on the red box to the right of the question brings up a window advising the user that this question may have particular importance to platform fire and life safety, and gives the user the opportunity to change the suggesting default weighting value of 5. The review group determined that platform age was particular significant considering the limited design life criteria originally used as the platform's design basis, and decided that a weighting value of 7.5 was representative of the increased level of concern about this factor, e.g., about 50% greater than other Tier 1 factors.

Upon entering a weighting value of 7.5, the red box changed to yellow, indicating that a value range must now be specified. In this example, the review group decided that the following value ranges were appropriate for grading the age risk factor:

A. zero to five years in age (Excellent)
B. between five and eight years in age (good)
C. between eight and twelve years in age (fair)
D. over twelve years in age (bad/of concern)

This determination was made based on the review group's knowledge and experience with similar platforms operating in the region; it was generally agreed that platforms of this design and around the same era experienced increasing numbers of problems after about eight years of operation, and especially so once they past twelve years in age. One reason for this was thought to be due to the limited corrosion allowances specified in the original design criteria. The control systems engineer also raised concern over increasing rates of failure of pneumatic valve operators due to diaphragm failures attributed to age-cracking of the elastomeric materials generally supplied for similar platforms. It was agreed that should a upper Tier level assessment be performed, the age of specific process components would be addressed in greater detail.

Note that in addition to red-level questions, any other selected question may be assigned a weight value different from the Tier level default value by simply entering the new value using the red button labeled "Assign Question Weights/Value Ranges." If the assigned value exceeds that of a Tier 1 level question, then FLAIM automatically shows it as a new red-level question and shades the question box in red.

Completing the Assessment Process

Once the GEFA assessment module has been calibrated, each subsequent assessment module is taken under consideration by the review group until such time that a consensus has been reached regarding question selection, weighting, and range values. The first-time user may follow this procedure by clicking on the file labeled "EXAMPLE PLATFORM" included on the enclosed floppy disk and paging through the question and assessment worksheets.

The next part of the assessment process is to enter the actual answers to the selected questions in order to perform the assessment. This may be performed in a number of ways, such as on-sight by an inspection team or in the local field office. Hard copy print-outs of the assessment sheet can be produced to use for data collection in the field to facilitate subsequent data input into FLAIM.

During the data entry process, FLAIM has been designed to call up an alert window in the event that a question is unanswered. Upon the user acknowledging the omission by clicking the OKAY button, FLAIM goes directly to the unanswered question for user convenience. Once all questions have been answered in a given risk module, the risk index for that module is calculated by clicking on the green window labeled "Calculate Assessment Risk Indices.

After all risk assessment modules have been completed, the overall fire and life safety index may be determined.

In this example, the following values were calculated for each assessment module:

GEFA	LOCA	VESA	LACA	OHFA	RIRA	LISA	SAMSA
2.29	2.02	1.74	1.83	1.39	2.03	1.89	1.78

The overall Fire and Life Safety Risk Index for the example platform was calculated to be 1.87. This determination was based on a group consensus that individual assessment modules should be weighted equally in the Tier 1 review. Based on the poor results of this initial assessment, the review team deemed it appropriate to recommend that a more detailed assessment be performed on the topsides, e.g., a Tier 2 review.

FLAIM also allows the user to see how changes to one or more question may impact both individual module indices and the overall fire and life safety risk index. Similarly, the user(s) can set individual risk indices target levels to reach a desired overall fire and life safety risk index and then "work-backwards" to determine what changes are necessary to meet the specified targets within each assessment module.

To assist the user in this analysis, FLAIM's design incorporates a display of the risk index differential showing how the index changed from the previous determined value after changes have been made to one or more question responses. This feature permits an understanding of, for example, how different risk reduction options compare with each other in reducing overall platform risk as defined by the review group. It also facilitates performance of cost-benefit analysis as explained in Chapter Twelve.

APPENDIX D

Historical Review of Offshore Development and Selected Accident Case Histories

The history of the offshore oil industry is directly related to issues of risk management. Development of offshore oil and gas deposits began at the turn of the century on the California coast and grew rapidly into a multi-billion dollar international industry upon which the world grew dependent.

In the United States, however, the expansion of offshore development has reversed direction during the last twenty years, and for the past decade, the U.S. Congress has imposed wide-spread moratoriums on offshore development along much of the outer continental shelf (OCS). The decline of the U.S. offshore industry was largely brought about by the 1969 Santa Barbara Channel blowout of Union Oil's Platform A and the subsequent ground swell of increasing environmental and political concern over the safety of offshore operations. Today, public perception of what constitutes and acceptable level of (environmental) risk has resulted in a political paralysis that has essentially stopped future development of offshore reserves in the Pacific and Atlantic coastal regions of the U.S.

Review of U.S.-- O.C.S. Development

A little over one-hundred years ago, in 1887, the first oil well was drilled off the coast of California.[1] Ironically, the birthplace of the offshore industry was in a small Santa Barbara County seaside community called Summerland. Timber wharves were constructed over the coastal waters from the shoreline to support drilling derricks and by the year 1900, drilling was taking place five-hundred feet from shore.[2] The use of timber construction evolved into the accepted method for offshore development that would not significantly change until after World War II.

In the early 1900's, offshore oil and gas development spread to the Gulf of Mexico. Cypress tree pilings were first used to construct wooden offshore drilling platforms on Ferry Lake in Caddo Parish, Louisiana, around 1910.[3] However, it was not until the early 1930's that drilling operations spread from the bayous and marshlands of the lower Mississippi Valley and into the shallow waters of that great sedimentary basin known as the Gulf of Mexico.[4]

The first Gulf of Mexico (GOM) platform was a wooden structure constructed in 1933 in 12 feet of water approximately 1000 yards off the shore of Creole, Louisiana. However, early development efforts were hampered by a lack of infrastructure necessary to support drilling and production operations. It was not until 1937 that the first significant offshore platform was constructed. Built by Brown & Root, Inc., the wooden platform had a base of 100 feet by 300 feet, and was located about 1 mile offshore in the Creole oil field. This platform was among industry's first effort to design for severe wave and wind loadings.

Between 1937 and 1942, about 25 wells were developed in the Gulf coast region. Similarly, California offshore development was proceeding, with Signal Oil and Gas Company leading the way in what is now Long Beach Harbor. However, World War II brought a temporary halt to further offshore development.

Following the War, Mobil Oil Company, then called Magnolia Oil Company, built the first offshore platform that employed the use of steel piles This platform, located off of Eugene Island, Louisiana, was a milestone in several respects: the 174 foot by 77 foot platform was designed for 150 mph winds and 18.5 foot waves; the drilling rig was the first to utilize skid-beams to permit the derrick to relocate to another well slot; and the platform was located five miles from shore, considerably further than anything attempted up to that time.

In 1947, the birth of the template or steel jacket platform occurred with the construction of Superior Oil's Vermilion Block 71 platform in the GOM. This design was to become the industry standard for the next forty years. "Jacket" and "template," are used interchangeably in reference to the use of the tubular platform legs to house and guide (jacket) the pilings that secure the platform structure to the seabed.

The Superior platform was indeed superior to anything designed to date. Located beyond sight of land eighteen miles offshore in twenty feet of water, the self-contained platform measured 173 feet by 108 feet. A separate quarters platform was installed to accommodate crew members who accessed the nearby main drilling platform via a bridge.

In later platforms, the design and economic constraints of moving into deeper waters led to integrating the living quarters with the drilling and production operations on a single platform. As subsequently discussed, concern over fire and explosion exposure to the living quarters became a central issue in the early development of the North Sea sector of the U.K..

Within two years of the installation of the Superior platform there were a total of ten fixed platforms operating in the Gulf of Mexico. However, it was not until passage of the Submerged Lands Act of 1953, settling offshore ownership issues, that the growth of GOM platforms mushroomed. The 100 foot depth milestone was achieved in 1955 by Shell Oil Company with the installation of the Grand Isle Block 47 platform, the first platform to use skirt piles. Only four years later, the 200 foot depth milestone was broken and more than two-hundred platforms were operating in the GOM.

Over the course of the next twenty years, technological improvements in fabrication, design, and transportation allowed ever increasing water depths to be achieved. In the early 1970's, Tenneco Corporation placed a platform in 375 feet of water at a distance of 130 miles from shore, and Shell Oil installed a platform in 373 feet of water. Then in 1977, Shell Oil broke all records by placing the Cognac platform in 1020 feet of water in the GOM.[5] The structural steel for this one-quarter-billion-dollar platform weighs over 59,000 tons. Only the year before, Exxon had held the world record with the Hondo platform which was installed in 850 feet of water in the Santa Barbara Channel.[6]

Both the Hondo and Cognac platforms were unique in that they were the first platforms to employ sectionalized jackets to accommodate the great water depths. The Hondo platform was fabricated in two sections, towed to the launch site by barge, and mated at sea prior to upending; Cognac's jacket was installed in three vertical sections.

In 1988, just one week after the tragic Piper Alpha explosion and fire in the U.K. sector of the North Sea, Shell Oil completed the installation of the world's tallest (deepest) offshore structure, the Bullwinkle Platform in the GOM. This platform rests in 1615 feet of water and the top of the derrick stands 265 feet above the water line.[7]

North Sea O.C.S. Development

The development of North Sea oil and gas began in the mid-1960's and has rapidly expanded since then. Today, Brent Crude is used as an international price benchmark and Britain is a net exporter of crude oil with over 100 offshore platforms.[8]

The first North Sea offshore structures, owned by British Petroleum (BP), were steel jacket platforms located the West Sole gas field in 100 feet of water. By the end of the decade, four offshore gas fields were under development; however, gas prices suppressed further growth of the offshore gas industry.

In the early 1970's the development of offshore crude oil reservoirs in the North Sea began in earnest. Starting in 1972 and, except for a five year slump starting in the 1978, construction activity has been strong both in the Norwegian and U.K. sectors of the North Sea. British Petroleum was one of the industry's leaders with the development of the Forties Field located in over 400 feet of water. The steel jackets fabricated for this development were the world's largest ever constructed up to that time.

Shell closely followed BP with the development of the Auk field and Brent field, the latter being in over 460 feet of water. Numerous other orders for new platforms were placed in the period of 1974-1975, including Occidental's ill-famed Piper Alpha platform. One particularly large steel jacket structure constructed during the late 1970's and worthy of mention is BP's Magnus platform which sits in over 600 feet of water; overall platform weight is approximately 112,000 tons.[9]

Although not reviewed in detail herein, it should be mentioned that 1973 marked the introduction of the first platform designs based on concrete. The Beryl A platform for Mobil Oil and the Brent C platform for Shell were among the earliest concrete designs. For further details on the design and construction of gravity-base concrete structures, the reader is referred to Construction of Offshore Structures, by Professor B.C. Gerwick, Jr. of the University of California.[10]

The Committee on Assessment of Safety (CAS) of OCS Activities, appointed by the Marine Board of the National Research Council, categorized fire and explosion incidents on offshore platforms into two general groups:[11]

1) Fires and explosions caused by loss of well control, i.e., a "blowout."

2) Fires and explosions resulting from operational causes, e.g., from equipment failure, human error, or design that involve drilling or production operations other than blowouts.

The 1970's:

The Committee on Assessment of Safety found that for the period of 1970-1979, a total of 278 fires and explosions occurred in oil and gas operations on the U.S. outer continental shelf of which 270 occurred in the GOM. About 94% of these incidents occurred on fixed drilling and production platforms, and of these, nearly 89% involved (initiate with) production operations.[12]

The CAS further identified that nearly one third of the production incidents involved process equipment, and one half to two thirds of all fires and explosions can be attributed to equipment or mechanical failure, whereas the rest are linked to human error -- mainly poor judgment.[13] (Note: it is now generally recognized that human and organizational error accounts for about two thirds to four fifths of all offshore incidents[14]).

The second most frequent cause of operational-type fires was identified as accumulations of flammable gas within enclosed spaces, particularly during drilling. The CAS identified gas explosions due to entrapment as a significant factor in the difference between the rate at which fires and explosions occurred (for this period) between North Sea platforms and those in U.S. waters.

For example, data from the Norwegian council for Scientific and Industrial Research put the annual risk of fire and explosion at 1.3 for the period of 1976-1978, whereas U.S. platforms showed a comparable annual risk of 0.0204 for the period of 1977-1979.[15] Another way of expressing this is to say that it was approximately 65 times more likely (6500%) that a North Sea platform would experience a fire and explosion during the late 1970's as compared to a platform in the GOM.

The 1980's

Data collected from over 1800 offshore accidents over the last twenty years for the Worldwide Offshore Accident Databank (WOAD) show a reduction in frequency for the major types of accidents in the 1980's. WOAD records indicate[16] that during the 1970's a total of seventeen fixed platforms were totally destroyed. This figure dropped to seven in the 1980's. This improvement was primarily due to improved blowout control, better operator training, and generally a greater emphasis on safety management, improved designs, and, in so far as the North Sea is concerned, the systematic use or risk analysis (introduced in Norway in 1981).

Despite improvements in platform safety during the last decade, data spanning from 1955-1990 clearly shows that blowouts, fires, and explosions account for nearly two thirds of all offshore accidents on fixed platforms.[17,18,19] Arguably, the greatest hazard to production-drilling-quarters (PDQ) platforms are fires and explosions,[20] and that most offshore accidents are due to some form of human failing rather than the lack of technology.[21,22,23]

In order to gain a further understanding of the nature of fire and explosion incidents, and build a framework for the analytical portion of FLAIM, the following section examines selected case histories of major fires and explosion on fixed offshore structures that have occurred over the past twenty years.

Early GOM Fire Incidents

The infamous Santa Barbara Channel blowout on Union Oil's Platform "A" ended the decade of the 1960's and marked a turning point for the offshore oil industry as well as for the environmental protection movement. Shortly thereafter, three major fires and explosions occurred in rapid succession in the GOM that would lead to the formal introduction of system engineering techniques to the platform design process.

Chevron's Main Pass Block 41, Platform C Fire

The year of 1970 was only one month old when a mechanical failure on Chevron's Platform C allowed an uncontrolled flow of hydrocarbon to escape to the atmosphere. Ignition of the ensuing vapor cloud resulted in a fire that lasted throughout the month of February and into March before extinguishment was achieved. It was thought that a pipe failure, due to sand erosion, caused the initial release. The platform was unattended, so that there were no personnel injuries or loss of life, but the platform was a total loss.

In this incident, the automatic shutdown system failed to control the release and fire spread into the wellbay and involved several wellheads. The only way control and extinguishment was eventually achieved was by drilling three relief wells, a time consuming process. A major oil spill resulted from this fire in which over 30,000 barrels of crude reportedly escaped.

Chevron was reportedly found guilty of negligence in this incident and heavily fined on five counts for failure to properly maintain or provide required safety devices. Reportedly some of the downhole safety valves were removed due to sanding problems in order to enhance production. As a result, the emergency shutdown system could not stop the flow of crude and the fire situation quickly escalated into a major conflagration.

Shell's Bay Marchand, Block 26, Platform B Fire

The Offshore industry was still dealing from public outcry caused by the Chevron incident when on December 1, 1970, the Shell Oil Company Platform B in the Bay of Marchand off the Louisiana coast had a blowout and major fire. The incident killed four employees, injured thirty-six, and destroyed the twenty-two well platform.[24]

In order to minimize environmental damage and reduce oil pollution, Shell elected to allow the fire to burn until relief wells could be drilled. This required about four and one-half months to complete, during which time about 53,000 barrels of crude were reportedly spilled (some estimates place this amount much higher due to subsurface flow). Ten of the eleven wild wells were controlled by drilling relief wells, and the last well fire was extinguished by the famous fire fighter, Red Adair, using high pressure water jets on April 16, one hundred and thirty-six days after the initial fire.[25]

The Shell accident occurred during a wireline work-over operation that led to loss of well control. Eleven of twenty-two completed wells became involved in fire. The subsequent investigation identified human error as a contributing factor leading to the initial blowout. This incident led to significant pollution of nearby beaches and fishing grounds.

> [Note: it is of historical interest that Professor Robert Bea of the University of California, Berkeley, Departments of Civil Engineering and Naval Architecture and Offshore Engineering was employed for Shell Oil at the time of this incident and was the design engineer for both the original platform and replacement structure.]

AMOCO's Eugene Island Block 215 Platform B Fire

In mid-October of 1971 yet another major offshore fire occurred in the GOM, involving American Oil Company's Eugene Island Platform B.. Fortunately there were not any fatalities nor injuries, and only a small oil spill resulted. However, the entire platform was involved in fire. The incident began with a mechanical failure in an oil pump and the ensuing fire rapidly escalated into a major conflagration leading to loss of the platform.

There were several other serious platform fires during this same period that, although did not destroy the involved platforms, did result in injuries and loss of life. The Chambers and Kennedy Block 189 Platform A experienced a fire caused by welding that left nine dead. The National Transportation Safety Board concluded that "this casualty poses serious doubt as to the effectiveness of voluntary safety practices in preventing accidents."[26]

Only three weeks earlier, Shell's Eugene Island Block 259 Platform C experienced an explosion involving a water heater that killed three crew members and injured seven. Then in October, Gulf's Block 134 Platform T had a sump tank fire that left one dead and two injured. About five weeks later, Humble's Block 73 Platform C experienced an explosion in a glycol reboiler that killed three men and injured thirteen.[27]

System Design Analysis and API RP 14C

Largely as a result of the aforementioned incidents the American Petroleum Institute developed and introduced in the early 1970's a new recommended practice (RP), API RP-14C, *Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems on Offshore Production Platforms.*[28] This RP was the first attempt by the offshore industry to provide designers with guidelines for the design of topside safety systems based on a systems engineering approach.

API RP 14C found wide acceptance among both designers and regulators, and was soon adopted and mandated by the U.S. Geological Survey (now the Minerals Management Service or MMS) for use on all new OCS platforms. It provided, and still provides, a simplified systems analysis technique, referred to as Systems Design Analysis (SDA), as a tool that designers use to ensure platform production and process systems and equipment are adequately protected with redundant safety devices.

Recent OCS fire incidents

In the December, 1972 safety study published by the Marine Board of the National Academy of Engineers[29] found that in almost all platform fires, other than those resulting from major blowouts, human error has been a factor. The Board sites (1) inadequate preplanning, (2) ineffective supervision, (3) workmen's ignorance of the presence of fire hazards as three prominent human factors. Not surprising, the Board's study identified the time of greatest fire risk was during maintenance and construction work on the platform; especially in cases where more than one job was in progress and under separate supervision.

This finding has not changed during the past two decades, nor has the basic causes of total platform losses significantly changed.[30] Recent tragic platform fires serve to illustrate that fire risk management for offshore structures has not, as yet, effectively deal with the human factor variable.

Arco's South Pass Block 60 Platform B

Human error was the direct cause of a fire that destroyed the Arco South Pass Block 60 Platform on March 19, 1989, leaving seven men dead and several badly injured.[31] Maintenance and construction work was in progress that involved the installation of a gas pipeline. A previous accident caused by a barge anchor chain hooking a two inch gas line and shearing it off necessitated an emergency repair on the main 18 inch gas riser.

When construction workers cut into the 18 inch gas riser, using a cold-cut machine (as opposed to a cutting torch), they discovered that the pipeline had not been completely purged of hydrocarbons, nor had they checked for this possibility prior to beginning work. As a result, high pressure gas and condensate rapidly escaped when the riser was penetrated. The escaping flammable fluids could not be controlled; the resulting vapor cloud found a source of ignition and a large fire ensued.

Intense heat caused subsequent failures of other blocked-in pipelines resulting in explosions and further damage to the platform. The uncontrolled fire spread from the cellar deck to the above production and drilling decks. Attempts to fight the fire from adjacent construction support vessels were unsuccessful and the platform was lost. The vessel Bo-Truc 20 which was moored adjacent to the platform was also severely damaged.

Several human error factors contributed to this incident: 1) workers failed to realize that the pipeline and riser could not be completely purged of hydrocarbons in the manner planned due to high points (traps) in the line, 2) workers failed to check if the line was indeed purged prior to cutting into the riser, 3) the operation was begun without installing an isolating blind flange at the shut-down valve, 4) a check valve that would have limited the amount of escaping fluids had been locked open, and 5) a lack of contractor supervision.

Poor preplanning, inadequate supervision, and ignorance were all prominent contributing factors to the loss of the Arco Platform B and the death of seven men.

Occidental's Block 15/17 Piper Alpha Platform, UKCS

The Piper Alpha conflagration of July 6, 1988 is the offshore industry's worst all-time fire and explosion incident.[32,33,34,35] As in the Arco Platform B incident previously described, human error was a primary aspect contributing to the loss of 167 lives and total destruction of the platform.

Piper Alpha was located on the U.K. continental shelf (UKCS) in the North Sea about 110 miles north-east of Aberdeen. The ten-leg steel jacket platform, installed in 474 feet of water, began production in late 1976. The production facilities onboard were sized to handle 250,000 barrels of oil/day (bpd) -- the equivalent throughput of a moderate size petroleum refinery.

There were many construction and maintenance activities occurring on the platform at the time of the incident in addition to ongoing production operations. Of the 226 people onboard, only 38 were directly employed by the platform operator, Occidental; the other 188 persons were contract employees working on several concurrent modification and maintenance projects.

One of the major modifications involved change out of the gas conservation (recovery) module. This work necessitated modifying the normal mode of production operations from "Phase 2" to "Phase 1", a mode of operations that had not been used since 1984. During the changeover to Phase 1 operation on July 3, several maintenance projects were planned to take advantage of the temporary shutdown of the gas treating section of the production train. On July 4, two days before the incident, several gas leaks occurred as well as upsets to the oil production separators and the gas compressors. In fact, during the three days preceding the incident, numerous reports of gas leaks occurred, and in one case the gas conservation module had to be evacuated -- two days before the incident.

On the evening of the catastrophe, a condensate injection pump in the Gas Compression Module (Module C) had tripped-out (automatically shut down), and the night shift operators, who had just reported for duty, responded by lining-up and starting the spare injection pump which had been previously shut down for preventative maintenance. Apparently the operators did not realize that a pressure relief valve had been earlier removed from the relief line of that pump and a blind flange had been temporarily installed to blank-off the open end of the line. The blind flange however was not made up to be leak tight, and when the operator started the spare pump, a violent spray of highly flammable high pressure hydrocarbon condensate escaped and immediately formed a large vapor cloud.

The initial explosion at 2200 hours killed the lead operator and his assistant (the Phase I operator), and caused extensive damage. The ignition source was thought to be hot work (welding) which was taking place in the east end of Module D, although other possibilities considered include hot surfaces, broken lighting fixtures, and sparks. The blast wave was severe enough to rupture a oil pipeline in the adjacent Production Module (Module B) resulting in a rapidly developing large oil fire engulfing the north end of the platform in dense smoke.

The fire, fed by a leak form the main oil line to shore which was interconnected to the Claymore and Tartan platforms, extended into Module C and down to the lower deck levels where the oil and gas risers enter the platform topsides decks. The Tartan gas pipeline riser failed from fire exposure shortly after the initial start of the incident, causing another huge explosion and engulfing much of the platform's lower deck in flames. At this point the platform was doomed, and subsequent failure of other risers led to the worst offshore platform conflagration in history.

The initial explosion caused failure of the main power supply on Piper, shutting down the control room, as well as disabling the fire protection systems. The diesel fire pumps had been put in manual-start mode due to diving operations, and could not be reached during the fire. It appears that the emergency shutdown valve on the Claymore riser failed to close, providing a huge inventory of high pressure gas to feed the fire. Lord Cullen considered these details as well as the global perspective of safety on the platform in concluding that the failure of management was a key factor in this accident; the safety policies were in place but the practice was not.

Negligence on the part of the platform operator, Occidental, is now being considered as grounds for prosecution by the Lord Advocate.[36] However, poor management of human and organizational errors (HOE) is not necessarily due to a lack of diligence; rather it is due largely to a lack of a formalized method for evaluating and managing them.[37]

---

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APPENDIX E

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APPENDIX F

POTENTIAL LOSS OF CONTAINMENT EVENTS OFFSHORE PRODUCTION PLATFORMS

Loss of Containment (LOC) events may generalized into three causal factor groups:
1) events directly caused by human error,
2) events resulting from mechanical/material failures, and \
3) external events.

The following list† is provided to assist users of FLAIM with assessing those types of LOC events most likely to be experienced on any given platform.

F1.0 HUMAN ERROR RELATED EVENTS

Open discharge pathways to atmosphere in production systems

F1.1 Failure to close:

- operator fails to close drain, vent, bleed or similar valve that discharges to the atmosphere
- operator fails to completely close valve (intentionally or unintentionally)
- worker fails to properly install blind flange, plug, or shutoff valve
- valve actuator connected backwards
- operator fails to close inlet valve to tank resulting in overfill
- workers fail to close all vessel appurtenances before startup

F1.2 Failure to keep closed/contained

- operator opens valve while system is pressured
- workers open system that has not be properly depressured
- improper calibration of pressure relief valve setting (operating pressure point)
- improper maintenance of pump and valve packing glands
- improper selection of gasketing material for service
- piping or process component installed with incorrect materials or rating for service conditions
- improper preventive maintenance and inspection

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† Derived in part from Guidelines for Vapor Release Mitigation, Center for Chemical Process Safety, American Institute of Chemical Engineers, 1988, pp. 123 - 127.

- inadequate safe work practices and operating procedures
- failure to supervise work crews
- failure to properly plan work and analyze hazards
- inadequate training and certification of workers

F2.0 *Equipment Failure*

F2.1 Mechanical/Material failure during normal operations

- control valve failure causes direct overpressure, e.g., choke erosion
- control valve failure causes loss of level allowing gas blowby and overpressure
- control valve closes but fails to seat
- fatigue failure of small piping connections
- sulfide/chloride stress cracking of piping or process components
- sand erosion/corrosion or piping or process components
- welding defects in heat affected zone -- failure to post weld heat treat
- undetected fabrication flaws
- undetected installation flaws
- material fails to meet specification requirements for service conditions

F2.2 Mechanical/Material failure During Abnormal Operations

- loss of power opens all fail-safe vent valves to atmosphere
- excessive pressure exceeds gasket or packing gland ratings
- stress rupture due to hydraulic surge pressures from liquid slugs, sudden valve closures, or large pumps starting without proper line-up.
- thermal stress rupture from loss of circulation in heated streams, loss of coolant, or failure to provide thermal relief in blocked-in liquid packed sections of piping
- compressor failure allowing backflow of high pressure discharge gas into lower pressure rated suction piping

F3.0 External Events

- impact from dropped objects
- hot work
- boat collision
- helicopter crash
- extreme weather conditions
- extreme wave conditions
- seismic activity

- soil failures
- sabotage
- labor disputes
- exposure from adjacent platform events

APPENDIX G

FLAIM SOURCE CODE

FLAIM

```
=ECHO(FALSE)
=HIDE()
=SHOW.TOOLBAR(1,FALSE,1)
=SHOW.TOOLBAR(5,FALSE,1)
=DIALOG.BOX(startup)
=SET.VALUE($L$13:$L$17,"")
=SET.VALUE($L$34,1)
=SET.VALUE($L$27,2)
=SET.VALUE($L$54,1)
=SET.VALUE($L$41,1)
=SET.VALUE($L$61,1)
=SET.VALUE($L$73,1)
=SET.VALUE($L$105:$L$109,0)
=SET.VALUE($L$117,1)
=SET.VALUE($L$87,5)
=DIALOG.BOX(identify)
=DIALOG.BOX(assess)
=IF($L$34=1)
=ELSE()
=   DIALOG.BOX(sprdsht_assess)
=END.IF()
=DIALOG.BOX(h2s)
=IF($L$27=1)
=   ALERT("The user should be aware that separate life safety assessment is
recommended for platforms handling H2S above 20 ppm.  This component of FLAIM is
for future development and is not covered in the scope of this present work.",3)
=ELSE()
=END.IF()
=DIALOG.BOX(assess_type)
=Callshts(call_sprdsht)
=DIALOG.BOX(begin_session)
=RETURN()
```

new_session

```
=DIALOG.BOX(assess_type)
=DIALOG.BOX(assess)
=DIALOG.BOX(sprdsht_assess)
=Callshts(call_sprdsht)
=RETURN()
```

Platid

```
=CREATE.OBJECT(6,"R2C2",175,9,"R3C2",334,11,,TRUE)
=TEXT.BOX("Platform  Name:  "&$L$13)
```

```
=FORMAT.FONT("Geneva",10,FALSE,FALSE,FALSE,FALSE,1,FALSE,FALSE,,1,14)
=CREATE.OBJECT(6,"R4C2",176,7,"R5C2",334,9,,TRUE)
=TEXT.BOX("Platform Lease: "&$L$15)
=FORMAT.FONT("Geneva",10,FALSE,FALSE,FALSE,FALSE,1,FALSE,FALSE,,1,15)
=RETURN()
```

Initial_wts

```
=IF(GET.CELL(5)=1)
=   FORMULA(5,OFFSET(SELECTION(),0,5,1,1))
=ELSE.IF(GET.CELL(5)=2)
=   FORMULA(3,OFFSET(SELECTION(),0,5,1,1))
=ELSE()
=   FORMULA(1,OFFSET(SELECTION(),0,5,1,1))
=END.IF()
=RETURN()
```

Generate_grades

```
=SELECT("grade")
=SELECT(OFFSET(SELECTION(),1,0,1,1))
=WHILE(GET.FORMULA(ACTIVE.CELL())<>"")
=  IF(AND(GET.FORMULA(OFFSET(SELECTION(),0,-
1,1,1))="",GET.CELL(38,OFFSET(SELECTION(),0,-1,1,1))<>1))
=       ALERT("You have not provided a grade for this question.",1)
=      SELECT(OFFSET(SELECTION(),0,-3,1,1))
=      SELECT(OFFSET(SELECTION(),0,2,1,1))
=      HALT()
=  ELSE()
=     IF(OR(GET.CELL(5)=1,GET.CELL(5)=2))
=         Numeric_format1()
=     ELSE.IF(OR(GET.CELL(5)=3,GET.CELL(5)=4))
=         Y_N_format()
=     ELSE.IF(OR(GET.CELL(5)=5,GET.CELL(5)=6))
=         Grade_format()
=     ELSE.IF(OR(GET.CELL(5)=7,GET.CELL(5)=8))
=         N_Y_format()
=     ELSE.IF(OR(GET.CELL(5)=9,GET.CELL(5)=10))
=         Numeric_format2()
=     ELSE()
=     END.IF()
=     SELECT(OFFSET(SELECTION(),1,0,1,1))
=  END.IF()
=NEXT()
=RETURN()
```

Numeric_format1 - low value/bad

```
=IF(OR(GET.CELL(5,OFFSET(SELECTION(),0,-1,1,1))<=OFFSET(SELECTION(),0,9,1,1)))
=   FORMULA(0,OFFSET(SELECTION(),0,3,1,1))
=ELSE.IF(AND(GET.CELL(5,OFFSET(SELECTION(),0,-
1,1,1))<=OFFSET(SELECTION(),0,8,1,1),GET.CELL(5)>=OFFSET(SELECTION(),0,9,1,1))
)
```

```
=   FORMULA(1,OFFSET(SELECTION(),0,3,1,1))
=ELSE.IF(AND(GET.CELL(5,OFFSET(SELECTION(),0,-
1,1,1))<=OFFSET(SELECTION(),0,7,1,1),GET.CELL(5)>=OFFSET(SELECTION(),0,8,1,1))
)
=   FORMULA(2,OFFSET(SELECTION(),0,3,1,1))
=ELSE.IF(AND(GET.CELL(5,OFFSET(SELECTION(),0,-
1,1,1))<=OFFSET(SELECTION(),0,6,1,1),GET.CELL(5)>=OFFSET(SELECTION(),0,7,1,1))
)
=   FORMULA(3,OFFSET(SELECTION(),0,3,1,1))
=ELSE()
=   FORMULA(4,OFFSET(SELECTION(),0,3,1,1))
=END.IF()
=RETURN()
```

Numeric_format2 - low value/good

```
=IF(OR(GET.CELL(5,OFFSET(SELECTION(),0,-1,1,1))>=OFFSET(SELECTION(),0,9,1,1)))
=   FORMULA(0,OFFSET(SELECTION(),0,3,1,1))
=ELSE.IF(AND(GET.CELL(5,OFFSET(SELECTION(),0,-
1,1,1))>=OFFSET(SELECTION(),0,8,1,1),GET.CELL(5)<=OFFSET(SELECTION(),0,9,1,1))
)
=   FORMULA(1,OFFSET(SELECTION(),0,3,1,1))
=ELSE.IF(AND(GET.CELL(5,OFFSET(SELECTION(),0,-1,1,1))
>=OFFSET(SELECTION(),0,7,1,1),GET.CELL(5)<=OFFSET(SELECTION(),0,8,1,1)))
=   FORMULA(2,OFFSET(SELECTION(),0,3,1,1))
=ELSE.IF(AND(GET.CELL(5,OFFSET(SELECTION(),0,-1,1,1))
>=OFFSET(SELECTION(),0,6,1,1),GET.CELL(5)<=OFFSET(SELECTION(),0,7,1,1)))
=   FORMULA(3,OFFSET(SELECTION(),0,3,1,1))
=ELSE()
=   FORMULA(4,OFFSET(SELECTION(),0,3,1,1))
=END.IF()
=RETURN()
```

Y_N_format

```
=IF(GET.FORMULA(OFFSET(ACTIVE.CELL(),0,-1,1,1))="Y")
=   FORMULA(4,OFFSET(ACTIVE.CELL(),0,3,1,1))
=ELSE()
=   FORMULA(0,OFFSET(ACTIVE.CELL(),0,3,1,1))
=END.IF()
=RETURN()
```

N_Y_format

```
=IF(GET.FORMULA(OFFSET(ACTIVE.CELL(),0,-1,1,1))="Y")
=   FORMULA(0,OFFSET(ACTIVE.CELL(),0,3,1,1))
=ELSE()
=   FORMULA(4,OFFSET(ACTIVE.CELL(),0,3,1,1))
=END.IF()
=RETURN()
```

Grade_format

```
=IF(GET.FORMULA(OFFSET(ACTIVE.CELL(),0,-1,1,1))="A")
```

```
=   FORMULA(4,OFFSET(ACTIVE.CELL(),0,3,1,1))
=ELSE.IF(GET.FORMULA(OFFSET(ACTIVE.CELL(),0,-1,1,1))="B")
=   FORMULA(3,OFFSET(ACTIVE.CELL(),0,3,1,1))
=ELSE.IF(GET.FORMULA(OFFSET(ACTIVE.CELL(),0,-1,1,1))="C")
=   FORMULA(2,OFFSET(ACTIVE.CELL(),0,3,1,1))
=ELSE.IF(GET.FORMULA(OFFSET(ACTIVE.CELL(),0,-1,1,1))="D")
=   FORMULA(1,OFFSET(ACTIVE.CELL(),0,3,1,1))
=ELSE()
=   FORMULA(0,OFFSET(ACTIVE.CELL(),0,3,1,1))
=END.IF()
=RETURN()
```

Calculate_risk_index

```
=Generate_grades()
=SELECT("grade")
=SELECT(OFFSET(SELECTION(),1,0,1,1))
=WHILE(GET.FORMULA(ACTIVE.CELL())<>"")
=   IF(OR(GET.CELL(5)=1,GET.CELL(5)=3))
=
FORMULA(PRODUCT(OFFSET(SELECTION(),0,2,1,1),OFFSET(SELECTION(),0,3,1,1)),OF
FSET(SELECTION(),0,4,1,1))
=  ELSE.IF(OR(GET.CELL(5)=5,GET.CELL(5)=7))
=
FORMULA(PRODUCT(OFFSET(SELECTION(),0,2,1,1),OFFSET(SELECTION(),0,3,1,1)),OF
FSET(SELECTION(),0,4,1,1))
=  ELSE.IF(GET.CELL(5)=9)
=    FORMULA(PRODUCT(OFFSET(SELECTION(),0,2,1,1),
OFFSET(SELECTION(),0,3,1,1)),OFFSET(SELECTION(),0,4,1,1))
=   ELSE.IF(AND(GET.CELL(5)=2,GET.FORMULA(OFFSET(ACTIVE.CELL(),0,1,1,1))<>""))
=    FORMULA((SUMPRODUCT(OFFSET(SELECTION(),0,2,
OFFSET(SELECTION(),0,1,1,1)+1,1),OFFSET(SELECTION(),0,3,OFFSET(SELECTION(),0,
1,1,1)+1,1)))/(SUM(OFFSET(SELECTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1))),
OFFSET(SELECTION(),0,4,1,1))
=   ELSE.IF(AND(GET.CELL(5)=4,GET.FORMULA(OFFSET(ACTIVE.CELL(),0,1,1,1))<>""))
=
FORMULA((SUMPRODUCT(OFFSET(SELECTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1
),OFFSET(SELECTION(),0,3,OFFSET(SELECTION(),0,1,1,1)+1,1)))/(SUM(OFFSET(SELE
CTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1))),OFFSET(SELECTION(),0,4,1,1))
=   ELSE.IF(AND(GET.CELL(5)=6,GET.FORMULA(OFFSET(ACTIVE.CELL(),0,1,1,1))<>""))
=
FORMULA((SUMPRODUCT(OFFSET(SELECTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1
),OFFSET(SELECTION(),0,3,OFFSET(SELECTION(),0,1,1,1)+1,1)))/(SUM(OFFSET(SELE
CTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1))),OFFSET(SELECTION(),0,4,1,1))
=   ELSE.IF(AND(GET.CELL(5)=8,GET.FORMULA(OFFSET(ACTIVE.CELL(),0,1,1,1))<>""))
=
FORMULA((SUMPRODUCT(OFFSET(SELECTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1
),OFFSET(SELECTION(),0,3,OFFSET(SELECTION(),0,1,1,1)+1,1)))/(SUM(OFFSET(SELE
CTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1))),OFFSET(SELECTION(),0,4,1,1))
=
ELSE.IF(AND(GET.CELL(5)=10,GET.FORMULA(OFFSET(ACTIVE.CELL(),0,1,1,1))<>""))
```

```
=
FORMULA((SUMPRODUCT(OFFSET(SELECTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1
),OFFSET(SELECTION(),0,3,OFFSET(SELECTION(),0,1,1,1)+1,1)))/(SUM(OFFSET(SELE
CTION(),0,2,OFFSET(SELECTION(),0,1,1,1)+1,1))),OFFSET(SELECTION(),0,4,1,1))
= ELSE()
= END.IF()
= SELECT(OFFSET(SELECTION(),1,0,1,1))
=NEXT()
=transfer_to_show_assessments()
=DIALOG.BOX(show_assessments)
=overall_FLAIM()
=RETURN()
```

transfer_to_show_assessments

```
=IF('Macro1-text format'!$L$41=1)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$K$131)
=   FORMULA('Macro1-text format'!$K$131-'Macro1-text format'!$P$2,'Macro1-
text format'!$K$132)
=   FORMULA("GENERAL",$K$127)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$P$2)
=ELSE.IF('Macro1-text format'!$L$41=2)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$K$131)
=   FORMULA('Macro1-text format'!$K$131-'Macro1-text format'!$Q$2,'Macro1-
text format'!$K$132)
=   FORMULA("LOCA",$K$127)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$Q$2)
=ELSE.IF('Macro1-text format'!$L$41=3)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$K$131)
=   FORMULA('Macro1-text format'!$K$131-'Macro1-text format'!$R$2,'Macro1-
text format'!$K$132)
=   FORMULA("VESA",$K$127)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$R$2)
=ELSE.IF('Macro1-text format'!$L$41=4)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$K$131)
=   FORMULA('Macro1-text format'!$K$131-'Macro1-text format'!$S$2,'Macro1-
text format'!$K$132)
=   FORMULA("LACA",$K$127)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$S$2)
=ELSE.IF('Macro1-text format'!$L$41=5)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$K$131)
=   FORMULA('Macro1-text format'!$K$131-'Macro1-text format'!$T$2,'Macro1-
text format'!$K$132)
=   FORMULA("OHFA",$K$127)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$T$2)
=ELSE.IF('Macro1-text format'!$L$41=6)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$K$131)
=   FORMULA('Macro1-text format'!$K$131-'Macro1-text format'!$U$2,'Macro1-
text format'!$K$132)
=   FORMULA("RIRA",$K$127)
=   FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$U$2)
=ELSE.IF('Macro1-text format'!$L$41=7)
```

```
=     FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$K$131)
=      FORMULA('Macro1-text format'!$K$131-'Macro1-text format'!$V$2,'Macro1-text format'!$K$132)
=    FORMULA("LISA",$K$127)
=    FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$V$2)
=ELSE()
=     FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$K$131)
=      FORMULA('Macro1-text format'!$K$131-'Macro1-text format'!$W$2,'Macro1-text format'!$K$132)
=    FORMULA("SAMSA",$K$127)
=    FORMULA(ROUND(SUM(!$H:$H)/SUM(!$F:$F),2),'Macro1-text format'!$W$2)
=END.IF()
=RETURN()
```

Callshts

```
=IF(AND($L$34=1,$L$54=1))
=   IF($L$41=1)
=     OPEN("General")
=      Platid()
=     SELECT("R7C1")
=         SAVE.AS($L$14&$L$13&"."&$M$42&"_ass")
=    HIDE()
=     OPEN("General factors")
=        SAVE.AS($L$14&$L$13&"."&$M$42)
=     SELECT("R7C1")
=  ELSE.IF($L$41=2)
=    OPEN("LOCA")
=     Platid()
=    SELECT("R7C1")
=        SAVE.AS($L$14&$L$13&"."&$M$43&"_ass")
=    HIDE()
=     OPEN("LOCA factors")
=     Platid()
=       SAVE.AS($L$14&$L$13&"."&$M$43)
=    SELECT("R7C1")
=  ELSE.IF($L$41=3)
=    OPEN("VESA")
=     Platid()
=    SELECT("R7C1")
=        SAVE.AS($L$14&$L$13&"."&$M$44&"_ass")
=    HIDE()
=     OPEN("VESA factors")
=     Platid()
=       SAVE.AS($L$14&$L$13&"."&$M$44)
=    SELECT("R7C1")
=  ELSE.IF($L$41=4)
=    OPEN("LACA")
=     Platid()
=    SELECT("R7C1")
=        SAVE.AS($L$14&$L$13&"."&$M$45&"_ass")
```

```
=     HIDE()
=      OPEN("LACA factors")
=      Platid()
=         SAVE.AS($L$14&$L$13&"."&$M$45)
=     SELECT("R7C1")
=   ELSE.IF($L$41=5)
=     OPEN("OHFA")
=      Platid()
=     SELECT("R7C1")
=         SAVE.AS($L$14&$L$13&"."&$M$46&"_ass")
=     HIDE()
=      OPEN("OHFA factors")
=      Platid()
=         SAVE.AS($L$14&$L$13&"."&$M$46)
=     SELECT("R7C1")
=    ELSE.IF('Macro1-text  format'!$L$41=6)
=     OPEN("RIRA")
=      Platid()
=     SELECT("R7C1")
=         SAVE.AS($L$14&$L$13&"."&$M$47&"_ass")
=    HIDE()
=      OPEN("RIRA factors")
=      Platid()
=         SAVE.AS($L$14&$L$13&"."&$M$47)
=     SELECT("R7C1")
=    ELSE.IF('Macro1-text  format'!$L$41=7)
=     OPEN("LISA")
=      Platid()
=     SELECT("R7C1")
=         SAVE.AS($L$14&$L$13&"."&$M$48&"_ass")
=    HIDE()
=      OPEN("LISA factors")
=      Platid()
=         SAVE.AS($L$14&$L$13&"."&$M$48)
=     SELECT("R7C1")
= ELSE()
=     OPEN("SAMSA")
=      Platid()
=     SELECT("R7C1")
=         SAVE.AS($L$14&$L$13&"."&$M$49&"_ass")
=    HIDE()
=      OPEN("SAMSA factors")
=      Platid()
=         SAVE.AS($L$14&$L$13&"."&$M$49)
=     SELECT("R7C1")
= END.IF()
=ELSE.IF(AND($L$34=2,$L$54=1))
=   IF($L$41=1)
=        OPEN($L$14&$L$13&"."&$M$42)
```

```
=     SELECT("R7C1")
=         OPEN($L$14&$L$13&"."&$M$42&"_ass")
=     SELECT("R7C1")
=     HIDE()
=   ELSE.IF($L$41=2)
=         OPEN($L$14&$L$13&"."&$M$43)
=     SELECT("R7C1")
=         OPEN($L$14&$L$13&"."&$M$43&"_ass")
=     SELECT("R7C1")
=     HIDE()
=   ELSE.IF($L$41=3)
=         OPEN($L$14&$L$13&"."&$M$44)
=     SELECT("R7C1")
=         OPEN($L$14&$L$13&"."&$M$44&"_ass")
=     SELECT("R7C1")
=     HIDE()
=   ELSE.IF($L$41=4)
=         OPEN($L$14&$L$13&"."&$M$45)
=     SELECT("R7C1")
=         OPEN($L$14&$L$13&"."&$M$45&"_ass")
=     SELECT("R7C1")
=     HIDE()
=   ELSE.IF($L$41=5)
=         OPEN($L$14&$L$13&"."&$M$46)
=     SELECT("R7C1")
=         OPEN($L$14&$L$13&"."&$M$46&"_ass")
=     SELECT("R7C1")
=     HIDE()
=   ELSE.IF($L$41=6)
=         OPEN($L$14&$L$13&"."&$M$47)
=     SELECT("R7C1")
=         OPEN($L$14&$L$13&"."&$M$47&"_ass")
=     SELECT("R7C1")
=     HIDE()
=   ELSE.IF($L$41=7)
=         OPEN($L$14&$L$13&"."&$M$48)
=     SELECT("R7C1")
=         OPEN($L$14&$L$13&"."&$M$48&"_ass")
=     SELECT("R7C1")
=     HIDE()
=  ELSE()
=         OPEN($L$14&$L$13&"."&$M$49)
=     SELECT("R7C1")
=         OPEN($L$14&$L$13&"."&$M$49&"_ass")
=     SELECT("R7C1")
=     HIDE()
=  END.IF()
=ELSE.IF(AND($L$34=2,$L$54=2))
=    IF($L$41=1)
```

```
=        OPEN($L$14&$L$13&"."&$M$42&"_ass")
=    SELECT("R7C1")
=       OPEN($L$14&$L$13&"."&$M$42)
=    SELECT("R7C1")
=    HIDE()
=  ELSE.IF($L$41=2)
=        OPEN($L$14&$L$13&"."&$M$43&"_ass")
=    SELECT("R7C1")
=       OPEN($L$14&$L$13&"."&$M$43)
=    SELECT("R7C1")
=    HIDE()
=  ELSE.IF($L$41=3)
=        OPEN($L$14&$L$13&"."&$M$44&"_ass")
=    SELECT("R7C1")
=       OPEN($L$14&$L$13&"."&$M$44)
=    SELECT("R7C1")
=    HIDE()
=  ELSE.IF($L$41=4)
=        OPEN($L$14&$L$13&"."&$M$45&"_ass")
=    SELECT("R7C1")
=       OPEN($L$14&$L$13&"."&$M$45)
=    SELECT("R7C1")
=    HIDE()
=  ELSE.IF($L$41=5)
=        OPEN($L$14&$L$13&"."&$M$46&"_ass")
=    SELECT("R7C1")
=       OPEN($L$14&$L$13&"."&$M$46)
=    SELECT("R7C1")
=    HIDE()
=  ELSE.IF($L$41=6)
=        OPEN($L$14&$L$13&"."&$M$47&"_ass")
=    SELECT("R7C1")
=       OPEN($L$14&$L$13&"."&$M$47)
=    SELECT("R7C1")
=    HIDE()
=  ELSE.IF($L$41=7)
=        OPEN($L$14&$L$13&"."&$M$48&"_ass")
=    SELECT("R7C1")
=       OPEN($L$14&$L$13&"."&$M$48)
=    SELECT("R7C1")
=    HIDE()
= ELSE()
=        OPEN($L$14&$L$13&"."&$M$49&"_ass")
=    SELECT("R7C1")
=       OPEN($L$14&$L$13&"."&$M$49)
=    SELECT("R7C1")
=    HIDE()
= END.IF()
=ELSE()
```

```
=   ALERT("You must create an assessment worksheet prior to performing an
assessment.",3)
=END.IF()
=RETURN()
```

overall_FLAIM

```
=FORMULA($P$2,$K$154)
=FORMULA($Q$2,$K$155)
=FORMULA($R$2,$K$156)
=FORMULA($S$2,$K$157)
=FORMULA($T$2,$K$158)
=FORMULA($U$2,$K$159)
=FORMULA($V$2,$K$160)
=FORMULA($W$2,$K$161)
=IF(COUNTA($P$2:$W$2)=8)
=     FORMULA((0.125*SUM($P$2:$W$2)),$K$162)
=ELSE()
=    FORMULA("",$K$162)
=END.IF()
=DIALOG.BOX(overall_FLAIM_dbox)
=RETURN()
```

tier_filter

```
=DIALOG.BOX(tier_select)
=SELECT("start")
=WHILE(GET.CELL(5)<>100)
=   IF(GET.CELL(5)=$L$61)
=      SELECT(OFFSET(SELECTION(),0,0,1+OFFSET(SELECTION(),0,4,1,1),5))
=      COPY()
=        activate_quests2()
=      SELECT("begin")
=      PASTE()
=        Initial_wts()
=      SELECT(OFFSET(SELECTION(),1,0,1,1))
=      DEFINE.NAME("begin")
=        activate_quests1()
=       SELECT("start")
=      SELECT(OFFSET(SELECTION(),1,0,1,1))
=      DEFINE.NAME("start")
=   ELSE()
=      SELECT("start")
=      SELECT(OFFSET(ACTIVE.CELL(),1,0,1,1))
=      DEFINE.NAME("start")
=   END.IF()
=NEXT()
=activate_quests2()
=SELECT("questions")
=ALIGNMENT(,TRUE,3,0)
=SELECT("R7C1")
```

```
=SAVE()
=activate_quests1()
=SELECT("R7C1")
=DEFINE.NAME("start")
=RETURN()
```

Copycell

```
=IF(GET.CELL(5)=0)
=     COPY("start:RC[-1]")
=ELSE.IF(GET.CELL(5)=1)
=     COPY("start:R[1]C[-1]")
=ELSE.IF(GET.CELL(5)=2)
=     COPY("start:R[2]C[-1]")
=ELSE.IF(GET.CELL(5)=3)
=     COPY("start:R[3]C[-1]")
=ELSE.IF(GET.CELL(5)=4)
=     COPY("start:R[4]C[-1]")
=ELSE.IF(GET.CELL(5)=5)
=     COPY("start:R[5]C[-1]")
=ELSE.IF(GET.CELL(5)=6)
=     COPY("start:R[6]C[-1]")
=ELSE.IF(GET.CELL(5)=7)
=     COPY("start:R[7]C[-1]")
=ELSE.IF(GET.CELL(5)=8)
=     COPY("start:R[8]C[-1]")
=ELSE.IF(GET.CELL(5)=9)
=     COPY("start:R[9]C[-1]")
=ELSE.IF(GET.CELL(5)=10)
=     COPY("start:R[10]C[-1]")
=ELSE.IF(GET.CELL(5)=11)
=     COPY("start:R[11]C[-1]")
=ELSE.IF(GET.CELL(5)=14)
=     COPY("start:R[14]C[-1]")
=ELSE.IF(GET.CELL(5)=15)
=     COPY("start:R[15]C[-1]")
=ELSE.IF(GET.CELL(5)=16)
=     COPY("start:R[16]C[-1]")
=ELSE.IF(GET.CELL(5)=26)
=     COPY("start:R[27]C[-1]")
=ELSE()
=END.IF()
=RETURN()
```

double_click

```
=ECHO(FALSE)
=IF('Macro1-text   format'!$L$41=1)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$42&"_ass","color_scheme")
```

```
=ELSE.IF('Macro1-text  format'!$L$41=2)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$43&"_ass","color_scheme")
=ELSE.IF('Macro1-text  format'!$L$41=3)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$44&"_ass","color_scheme")
=ELSE.IF('Macro1-text  format'!$L$41=4)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$45&"_ass","color_scheme")
=ELSE.IF('Macro1-text  format'!$L$41=5)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$46&"_ass","color_scheme")
=ELSE.IF('Macro1-text  format'!$L$41=6)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$47&"_ass","color_scheme")
=ELSE.IF('Macro1-text  format'!$L$41=7)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$48&"_ass","color_scheme")
=ELSE()
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$49&"_ass","color_scheme")
=END.IF()
=RETURN()
```

color_scheme

```
=ECHO(FALSE)
=IF(GET.CELL(38,ACTIVE.CELL())=3)
=    FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),1,80),'Macro1-text  format'!$K$90)
=    FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),81,80),'Macro1-text  format'!$K$91)
=    FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),1,80),'Macro1-text  format'!$K$97)
=    FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),81,80),'Macro1-text  format'!$K$98)
=  DIALOG.BOX(Red_flag)
=    FORMULA('Macro1-text  format'!$L$87,OFFSET(ACTIVE.CELL(),0,3,1,1))
=    IF('Macro1-text  format'!$L$87>=5)
=      FORMULA("*",OFFSET(ACTIVE.CELL(),0,-2))
=  ELSE()
=  END.IF()
=
IF(OR(GET.CELL(5,OFFSET(ACTIVE.CELL(),0,1,1,1))=1,GET.CELL(5,OFFSET(ACTIVE.CELL(),0,
1,1,1))=2))
=      PATTERNS(1,6,0)
=     GOTO($C$123)
=  ELSE.IF(GET.CELL(5,OFFSET(ACTIVE.CELL(),0,1,1,1))=9)
=      PATTERNS(1,6,0)
=     GOTO($C$123)
=  ELSE.IF(GET.CELL(5,OFFSET(ACTIVE.CELL(),0,1,1,1))=10)
=      PATTERNS(1,6,0)
=     GOTO($C$123)
=  ELSE()
=      PATTERNS(1,2,0)
=     GOTO($C$184)
=  END.IF()
=ELSE.IF(GET.CELL(38,ACTIVE.CELL())=6)
=    FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),1,80),'Macro1-text  format'!$K$97)
=   ACTIVATE("Macro1")
=   SELECT("threshold")
```

```
=  CLEAR()
=   DIALOG.BOX(set_number_levels)
=   SELECT("threshold")
=  COPY()
=    activate_quests2()
=  SELECT(OFFSET(ACTIVE.CELL(),0,6))
=  PASTE.SPECIAL(3,1,TRUE,TRUE)
=   SELECT(OFFSET(ACTIVE.CELL(),0,-8,1,1))
=   SELECT(OFFSET(ACTIVE.CELL(),0,2,1,1))
=   PATTERNS(1,2,0)
=ELSE.IF(GET.CELL(38,ACTIVE.CELL())=1)
=   ALERT("This is an inactive cell.  No inputs are allowed.",1)
=ELSE()
=    FORMULA(OFFSET(ACTIVE.CELL(),0,3),'Macro1-text format'!$L$117)
=     FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),1,80),'Macro1-text format'!$K$120)
=     FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),81,80),'Macro1-text format'!$K$121)
=  DIALOG.BOX(change_wt)
=    FORMULA('Macro1-text format'!$L$117,OFFSET(ACTIVE.CELL(),0,3))
=     IF('Macro1-text format'!$L$117>=5)
=       FORMULA("*",OFFSET(ACTIVE.CELL(),0,-2))
=  ELSE()
=  END.IF()
=
IF(OR(GET.CELL(5,OFFSET(SELECTION(),0,1,1))=1,GET.CELL(5,OFFSET(SELECTION(),0,1,1))=
2))
=        FORMULA(OFFSET(SELECTION(),0,6,1,1),'Macro1-text format'!$L$105)
=        FORMULA(OFFSET(SELECTION(),0,7,1,1),'Macro1-text format'!$L$106)
=        FORMULA(OFFSET(SELECTION(),0,8,1,1),'Macro1-text format'!$L$107)
=        FORMULA(OFFSET(SELECTION(),0,9,1,1),'Macro1-text format'!$L$108)
=        FORMULA(OFFSET(SELECTION(),0,10,1,1),'Macro1-text format'!$L$109)
=        FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),1,80),'Macro1-text format'!$K$97)
=        FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),81,80),'Macro1-text format'!$K$98)
=      DIALOG.BOX(set_number_levels)
=       ACTIVATE("Macro1")
=      SELECT("threshold")
=     COPY()
=       activate_quests2()
=     SELECT(OFFSET(ACTIVE.CELL(),0,6))
=     PASTE.SPECIAL(3,1,TRUE,TRUE)
=      SELECT(OFFSET(ACTIVE.CELL(),0,-8,1,1))
=      SELECT(OFFSET(ACTIVE.CELL(),0,2,1,1))
=  ELSE.IF(OR(GET.CELL(5,OFFSET(SELECTION(),0,1,1))=9,
GET.CELL(5,OFFSET(SELECTION(),0,1,1))=10))
=        FORMULA(OFFSET(SELECTION(),0,6,1,1),'Macro1-text format'!$L$105)
=        FORMULA(OFFSET(SELECTION(),0,7,1,1),'Macro1-text format'!$L$106)
=        FORMULA(OFFSET(SELECTION(),0,8,1,1),'Macro1-text format'!$L$107)
=        FORMULA(OFFSET(SELECTION(),0,9,1,1),'Macro1-text format'!$L$108)
=        FORMULA(OFFSET(SELECTION(),0,10,1,1),'Macro1-text format'!$L$109)
=        FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),1,80),'Macro1-text format'!$K$97)
=        FORMULA(MID(OFFSET(ACTIVE.CELL(),0,-1),81,80),'Macro1-text format'!$K$98)
```

```
=        DIALOG.BOX(set_number_levels)
=        ACTIVATE("Macro1")
=        SELECT("threshold")
=      COPY()
=        activate_quests2()
=      SELECT(OFFSET(ACTIVE.CELL(),0,6))
=      PASTE.SPECIAL(3,1,TRUE,TRUE)
=       SELECT(OFFSET(ACTIVE.CELL(),0,-8,1,1))
=       SELECT(OFFSET(ACTIVE.CELL(),0,2,1,1))
=  ELSE()
=  END.IF()
=END.IF()
=RETURN()
```

activate_quests1

```
=IF('Macro1-text  format'!$L$41=1)
=      ACTIVATE($L$14&$L$13&"."&$M$42)
=ELSE.IF('Macro1-text  format'!$L$41=2)
=      ACTIVATE($L$14&$L$13&"."&$M$43)
=ELSE.IF('Macro1-text  format'!$L$41=3)
=      ACTIVATE($L$14&$L$13&"."&$M$44)
=ELSE.IF('Macro1-text  format'!$L$41=4)
=      ACTIVATE($L$14&$L$13&"."&$M$45)
=ELSE.IF('Macro1-text  format'!$L$41=5)
=      ACTIVATE($L$14&$L$13&"."&$M$46)
=ELSE.IF('Macro1-text  format'!$L$41=6)
=      ACTIVATE($L$14&$L$13&"."&$M$47)
=ELSE.IF('Macro1-text  format'!$L$41=7)
=      ACTIVATE($L$14&$L$13&"."&$M$48)
=ELSE()
=      ACTIVATE($L$14&$L$13&"."&$M$49)
=END.IF()
=RETURN()
```

activate_quests2

```
=IF('Macro1-text  format'!$L$41=1)
=      ACTIVATE($L$14&$L$13&"."&$M$42&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=2)
=      ACTIVATE($L$14&$L$13&"."&$M$43&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=3)
=      ACTIVATE($L$14&$L$13&"."&$M$44&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=4)
=      ACTIVATE($L$14&$L$13&"."&$M$45&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=5)
=      ACTIVATE($L$14&$L$13&"."&$M$46&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=6)
=      ACTIVATE($L$14&$L$13&"."&$M$47&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=7)
=      ACTIVATE($L$14&$L$13&"."&$M$48&"_ass")
```

```
=ELSE()
=      ACTIVATE($L$14&$L$13&"."&$M$49&"_ass")
=END.IF()
=RETURN()
```

unhide_assess

```
=IF('Macro1-text  format'!$L$41=1)
=  HIDE()
=      UNHIDE($L$14&$L$13&"."&$M$42&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=2)
=  HIDE()
=      UNHIDE($L$14&$L$13&"."&$M$43&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=3)
=  HIDE()
=      UNHIDE($L$14&$L$13&"."&$M$44&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=4)
=  HIDE()
=      UNHIDE($L$14&$L$13&"."&$M$45&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=5)
=  HIDE()
=      UNHIDE($L$14&$L$13&"."&$M$46&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=6)
=  HIDE()
=      UNHIDE($L$14&$L$13&"."&$M$47&"_ass")
=ELSE.IF('Macro1-text  format'!$L$41=7)
=  HIDE()
=      UNHIDE($L$14&$L$13&"."&$M$48&"_ass")
=ELSE()
=  HIDE()
=      UNHIDE($L$14&$L$13&"."&$M$49&"_ass")
=END.IF()
=RETURN()
```

unhide_quests

```
=IF('Macro1-text  format'!$L$41=1)
=  HIDE()
=     UNHIDE($L$14&$L$13&"."&$M$42)
=ELSE.IF('Macro1-text  format'!$L$41=2)
=  HIDE()
=     UNHIDE($L$14&$L$13&"."&$M$43)
=ELSE.IF('Macro1-text  format'!$L$41=3)
=  HIDE()
=     UNHIDE($L$14&$L$13&"."&$M$44)
=ELSE.IF('Macro1-text  format'!$L$41=4)
=  HIDE()
=     UNHIDE($L$14&$L$13&"."&$M$45)
=ELSE.IF('Macro1-text  format'!$L$41=5)
=  HIDE()
=     UNHIDE($L$14&$L$13&"."&$M$46)
```

```
=ELSE.IF('Macro1-text  format'!$L$41=6)
=  HIDE()
=    UNHIDE($L$14&$L$13&"."&$M$47)
=ELSE.IF('Macro1-text  format'!$L$41=7)
=  HIDE()
=    UNHIDE($L$14&$L$13&"."&$M$48)
=ELSE()
=  HIDE()
=    UNHIDE($L$14&$L$13&"."&$M$49)
=END.IF()
=RETURN()
```

Doubleclick_Tier

```
=DIALOG.BOX(Choose_tier)
=IF('Macro1-text  format'!$L$41=1)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$42,"Tiers")
=ELSE.IF('Macro1-text  format'!$L$41=2)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$43,"Tiers")
=ELSE.IF('Macro1-text  format'!$L$41=3)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$44,"Tiers")
=ELSE.IF('Macro1-text  format'!$L$41=4)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$45,"Tiers")
=ELSE.IF('Macro1-text  format'!$L$41=5)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$46,"Tiers")
=ELSE.IF('Macro1-text  format'!$L$41=6)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$47,"Tiers")
=ELSE.IF('Macro1-text  format'!$L$41=7)
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$48,"Tiers")
=ELSE()
=ON.DOUBLECLICK($L$14&$L$13&"."&$M$49,"Tiers")
=END.IF()
=RETURN()
```

Tiers

```
=IF('Macro1-text  format'!$L$73=1)
=  FORMULA(1,ACTIVE.CELL())
=ELSE.IF('Macro1-text  format'!$L$73=2)
=  FORMULA(2,ACTIVE.CELL())
=ELSE()
=  FORMULA(3,ACTIVE.CELL())
=END.IF()
=RETURN()
```

FLAIM DIALOG BOXES

startup	5	69	412			
	223	0	2	666	370	Picture 1
	5	300	372			F L A I M ©
	5	125	395			FIRE AND LIFE SAFETY ASSESSMENT AND INDEXING METHODOLOGY
	5	218	419			FOR OFFSHORE PRODUCTION PLATFORMS
	5	322	443			by
	5	210	466			WILLIAM E. GALE, Jr., Ph.C., P.E., C.S.P.
	5	205	487			University of California at Berkeley
	1	567	469	64		START

identify	5	180	-30			PLATFORM IDENTIFICATION INFORMATION
	5	35	5			Platform
	6	34	23	171		
	6	35	79	171		
	6	34	139	171		
	6	35	197	171		
	6	35	255	171		
	5	35	61			Area/Block
	5	34	121			Lease
	5	35	178			Well Number
	5	34	237			Operator
	1	250	260	64		OK

h2s	5	150	50			
	5	17	13			Are H2S levels higher than 20 parts per million
	5	18	34			for hydrocarbon production ?
	11					
	12					Yes
	12					No
	1	276	74	64		OK

assess		180	30	310	110	
	5	6	5			
	11					
	12					New Platform Assessment
	12					Modify Existing Platform Assessment
	1	239	75	64		OK

assess_ type	5	150	-10			FIRE AND LIFE SAFETY ASSESSMENT OPTIONS
	5	4	4			
	11					
	12					GENERAL FACTORS ASSESSMENT (GEFA)
	12					LOSS OF CONTAINMENT ASSESSMENT (LOCA)
	12					VULNERABILITY TO ESCALATION ASSESSMENT (VESA)
	12					LAYOUT AND CONFIGURATION ASSESSMENT (LACA)
	12					OPERATIONS (HUMAN FACTOR) ASSESSMENT (OHFA)
	12					RISK REDUCTION ASSESSMENT (RIRA)
	12					LIFE SAFETY ASSESSMENT (LISA)
	12					SAFETY MANAGEMENT SYSTEM ASSESSMENT (SAMSA)
	1	326	178	64		OK

sprdsht_ assess	5	150	30			
	5	40	21			Which of the following do you wish to perform?
	11					
	12					Setup FLAIM input spreadsheet
	12					Perform FLAIM assessment
	1	333	72	64		OK

tier_select	5	85	60			
	5	50	12			Please identify the level you wish to copy to assessment sheet:
	11					
	12					Tier 1: General Assessment
	12					Tier 2: Detailed Assessment
	12					Tier 3: Further Detailed Assessment
	1	444	66	64		OK

Red_flag	5	9	9			
	5	89	5			Certain questions have been designated as "red-level" questions that
	5	84	25			may warrant a higher weighting value than Tier 1 level questions due to
	5	113	45			their importance to overall platform fire and life safety. The
	5	92	65			user has the option of assigning a unique weighting value to this
	5	68	85			question that reflects its importance. Indicate your preceived weighting
	5	205	105			value for the question below.
	5	6	141			Question:
	8	306	236	171		
	1	594	236	64		OK
	5	171	240			Associated weight
	5	6	161			Do instrumentation and control systems frequently malfunction? Never : A, Rarel
	5	6	181			y: B, Occasionally: C, Often: D, Always: F
	5	6	201			

begin_ session	5	160	32			
	5	20	18			You are now ready to begin your FLAIM session.
	1	150	61	64		OK

Choose_ tier	5	75	100			
	5	1	6			Select the Tier Level that you would like to choose questions for:
	11					
	12					Tier 1: Primary Level
	12					Tier 2: Secondary Level
	12					Tier 3: Tertiary Level
	1	440	61	64		OK

set_number _levels	5	8	1			
	5	18	16			Please identify the minimum value ranges for the following quantitative question:
	5	8	47			Question:
	5	8	70			Approximate response time for emergency service vessel assistance min
	5.5	8	93			
	5	8	116			
	5	180	172			Excellent ("A")
	5	210	205			Good ("B")
	5	218	236			Fair ("C")
	5	211	268			Poor ("D")
	5	218	299			Bad ("F")
	8	287	168	171		A
	8	287	200	171		B
	8	287	232	171		C
	8	287	264	171		D
	8	287	296	171		F
	1	589	289	64		OK

change_wt	5	8	40			
	5	63	4			The following question has an assigned weight shown in the box below.
	5	79	23			If you wish to change the weight of this question, please input the
	5	103	42			the weight that best captures the importance of the question.
	5	5	82			Question:
	8	305	177	171		
	1	569	181	64		OK
	5	170	181			Associated weight
	5	5	102			
	5	5	122			
	5	5	142			

show_ assessments	5	205	40			FLAIM Assessment
	5	23	4			FLAIM Assessment for:
	5	188	4			VESA
	5	101	47			Risk Index:
	5	18	72			Risk Index Differential:
	1	95	118	64		OK
	5	186	48			
	5	190	72			

overall_FLAIM_dbox	5	220	2			
	5	43	11			FLAIM
	5	23	28			Assessment
	5	27	45			Categories
	5	131	45			FLAIM Indices
	5	50	68			General
	5	70	91			LOCA
	5	71	114			VESA
	5	70	137			LACA
	5	70	159			OHFA
	5	71	182			RIRA
	5	74	205			LISA
	5	58	226			SAMSA
	5	17	52			___________
	5	130	52			___________
	1	90	306	64		OK
	5	20	268			OVERALL FLAIM INDEX:
	5	160	68			
	5	160	91			
	5	160	114			
	5	160	137			
	5	160	160			
	5	160	183			
	5	160	206			
	5	160	229			
	5	181	267			

1994 High Consequence Operations Safety Symposium
Sandia National Laboratories, Albuquerque, NM
July 12-14, 1994

A Methodology for Assessing and Managing Fire and Life Safety for Offshore Production Platforms

William E. Gale, Jr., Ph.D., P.E., C.S.P.
Consultant
Novato, CA

William H. Moore, Dr.Eng.
American Bureau of Shipping
New York, NY

Professor Robert G. Bea
Department of Naval Architecture & Offshore Engineering
and Department of Civil Engineering
University of California at Berkeley

Professor Robert B. Williamson
Department of Civil Engineering
University of California at Berkeley

Introduction

Following the 1988 *Piper Alpha* disaster in which 167 people lost their lives in industry's worst offshore platform accident, numerous inquiries and research efforts were set in motion. In the ensuing official investigation, Lord Cullen[1] recognized a principal change was needed in administering U.K. offshore safety regulations-- a move away from prescriptive, mechanistic safety regulations to an approach based on comprehensive goal setting objectives that could accommodate, *inter alia*, the influence of human and organizational factors in managing safety. Within the United States, a similar movement is taking place--both onshore and offshore.

In the wake of the Phillips Petrochemical Complex explosion and fire (October 23, 1989) in which 23 worker were killed, new process safety management (PSM) requirements were promulgated by OSHA.[2] Labor Secretary Dole noted that "the catastrophe at Phillips' complex underscores the need for effective implementation of good safety management systems in the petrochemical industry," and cited as primary contributors to the problem a lack of attention to: 1) recognition of hazards, 2) poorly maintained equipment, 3) poor planning, and 4) unsafe work practices.

Recognizing the importance of addressing human factors and operational errors in process safety management, OSHA's PSM regulations focus attention on the contribution of human factors in process hazard analysis. As pointed out by Fleger,[3] industry is now coping with the problem of how to perform human factors analysis as a part of the mandated process hazard analyses required by 29CFR1910.119. Fleger notes that quantitative techniques, such as *human reliability analysis* (HRA) are even more cumbersome than many types of other quantitative analyses, and suffers from the same limitations of uncertainties due to a lack of specific data or human error probabilities.[3]

In the case of *Piper Alpha*, the Safety Management System, e.g., the means to integrate and execute those aspects of platform design and operations that directly or indirectly influence achieving safe operating goals (Figure 1) was found to be deficient in several respects. This led to the present requirement for a formal safety assessment or "Safety Case," based on *quantified risk assessment* (QRA) tech-

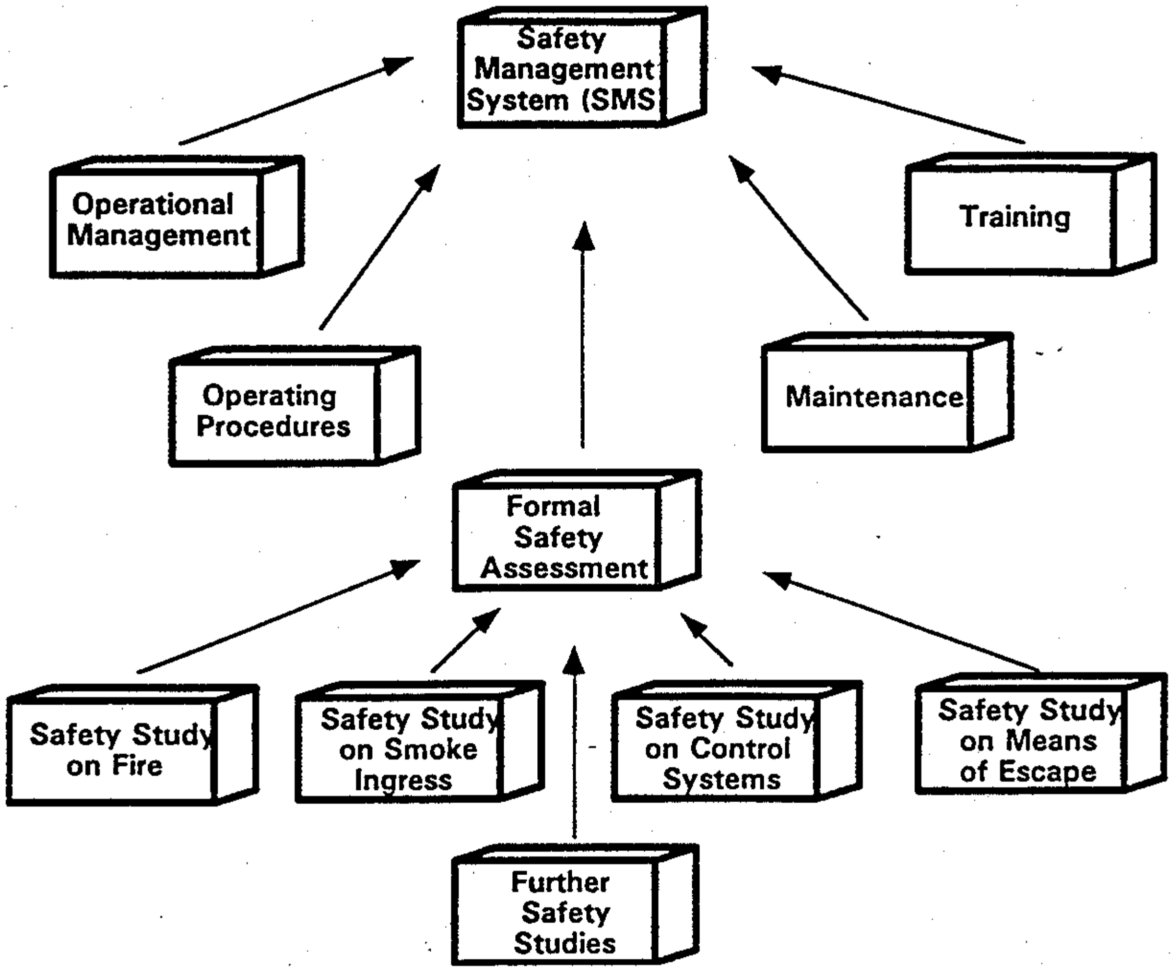


Figure 1

Interpretation of Safety Structure Proposed in the Cullen Report

Source: Interim Guidance Notes for the Design and Protection of Topside Structures Against Explosion and Fire, Steel Construction Institute SCI-P-112, Document No 243, January, 1992.

niques, to be included as part of the overall platform's SMS.[4]

The Cullen inquiry of the *Piper Alpha* accident concluded that techniques based on QRA (also commonly known as PRA) should be used to assess major hazards and to evaluate the means to reduce risk of accidental events on life safety features, e.g., the integrity of personnel refuge areas, escape routes, embarkation points and life-saving craft, etc.[1] However, as pointed out by the subsequent Fire and Blast Research Project's *Interim Guidance Notes,*[5] it is considered either impractical or impossible to carry out a rigorous QRA due to a lack of sufficiently detailed knowledge of the systems and their expected performance characteristics, or the lack of accurate probability data of initiating events, and the large uncertainties associated with determining consequences. Limited knowledge of probability distributions and limited/ incomplete event databases have been and continue to be long-standing obstacles to rigorous application of QRA offshore.

Meaningful data needed for performing rigorous QRAs on most U.S. Offshore Continental Shelf (OCS) platforms is also lacking. The present database maintained by the Minerals Management Service (MMS) has been recognized as lacking in several respects. A report by the National Research Council has recommended that MMS should develop a comprehensive system for collecting event and exposure date, calculating frequency and severity rates, analyzing trends, and performing several other functions necessary to produce usable data.[6,7]

This problem is one of the driving forces that has led to the development of the *Fire and Life safety Assessment Indexing Method* (FLAIM)-- a search for a means of integrating stochastic risk assessment approaches with deterministic and heuristic techniques to assess risk offshore, to identify deteriorating operations (both from a mechanical and management standpoint), and reveal emerging safety risks on older platforms. FLAIM's development sought to capture one of the main advantages of QRA-- the application of a quantified and structured approach to enable decisions to be reached on a rational and consistent basis while simplifying the assessment procedure and easing the burden of performing such studies. FLAIM is not intended to replace more thorough risk assessment techniques, however, but rather complement their usage when appropriate (and when meaningful data are available). FLAIM is primarily intended to provide a screening tool for platform operators and regulators to help them determine how to best improve existing safety management programs and direct limited resources for optimal risk mitigation.

Development of FLAIM

Following the loss of *Piper Alpha*, the U.S. Mineral Management Service (MMS) requested the National Academy of Sciences' Marine Board to assist them in investigating alternative strategies for the inspection and safety assessment of OCS platforms, with a view towards improving operational safety and inspection practices.[8]

Considerable effort was made to select members of the working committee, known as the Committee on Alternatives for Inspection (CAI), who not only had both the requisite expertise in OCS operations and safety management, but also would bring a balanced viewpoint with respect to public interests in environmental protection and safety.

CAI members reviewed the current OCS

inspection program and practices, appraised other inspection practices for "lessons-learned," including those of platforms in state waters as well as inspection practices in other industries (nuclear, etc.), reviewed MMS data bases and the OCS safety record, and developed evaluation criteria and alternative recommendations for consideration by MMS.

The CAI developed an inspection recommendation based upon developing *quantitative indices that characterize and measure the safety of individual offshore operations*. Several factors were identified that should be taken into account in developing sampling indices to characterize and measure platform safety, including:

- the occurrence of safety-related events onboard the platform,
- the occurrence of near-misses which could have caused an accident,
- the record of tests and inspections of safety equipment found in ill-repair,
- evidence of slipshod operation, e.g., poor maintenance, poor housekeeping, poor record keeping, etc.,
- the facility design, such as location and age,
- evidence of lax safety attitudes of managers, supervisors, or operating personnel, e.g., the safety "culture" and awareness factor,
- the overall safety record for all platforms operated by the operator, and
- the overall safety record for all operators with the region of operations.

The CAI suggested that from such quantitative, facility-specific information, a safety rating could be developed for each platform which would be updated continually with new data. The data base would be kept up to date by requiring that all event reports and specified operator's inspection and test results be sent to MMS. Onshore review of records could then comprise a substantial part of the inspection and assessment process, and onsite inspections (offshore) could be accomplished in a much more efficient and informed manner based on prior analysis of the information in the data base.

Finally, the CAI stressed *the importance of management's safety culture* and suggested that MMS make explicit in its safety management and inspection philosophy the monitoring of safety attitudes of the operators is essential, recognizing that subjective judgments will be involved in this process. However, CAI pointed out that subjective judgments should not be a deterrent, but rather MMS inspectors and supervisors should be trained in techniques for and the importance of monitoring safety attitudes.

The CAI cautioned against "compliance mentalities" in which some operators may perceive their responsibility and objective as to "simply pass inspection." CAI emphasized its belief that mere compliance with requirements/ regulations *does not equal safety,* and that in practice and by law, the operators bear the primary responsibility for safety. MMS's responsibility is to find the best and most effective means it can devise to motivate operators to meet their responsibility.

FLAIM's conception is rooted in all of the foregoing CIA principles and findings. FLAIM's development was geared to meeting the identified criteria in recognition of the need to fulfill a variety of functions to be successful. Foremost, it must be user-friendly, interactive, and pleasant to use--with the goal of *motivating platform operators* to monitor and manage the ever-change state of safety onboard their plat-

forms, rather than represent a burdensome and arduous task that is both time consuming and overly technically demanding. It must promote safety performance accountability in an efficient and effective manner.

Further, FLAIM was designed to be adaptable for use to both specific applications as well as specific operators who, hopefully, will choose to use their own proprietary and confidential databases to identify those risk contributors of most significance to the particular operations under scrutiny. In this regard, FLAIM does not presuppose that the risk contributors and their corresponding weighting algorithms used in this original work are absolute or rigid, but rather provisions have been purposefully designed to allow users to select, add, and change the values used herein, e.g., FLAIM is intended to serve as the basis or framework for developing site-specific models suited for the particular area and nature of operations, facility design, reservoir characteristics, and service demands for any given platform.

Therefore, FLAIM incorporates features that both explain the logic used in its development and allows modification of factors and algorithms when deemed suitable for the user. FLAIM is intended as a tool for platform operators-- to assist them in meeting their safety goals and responsibilities-- using their own databases, knowledge, and experience, as well as those existing at large within industry to do so.

FLAIM's architecture was developed in recognition of the significant role that human and organization error (HOE) plays in promoting offshore accidents, while accounting for the fact that older topside systems, besieged by years of demanding service under harsh conditions, can be expected to have higher rates of mechanical or material related failures than their newer counterparts. *Over 80% of high consequence offshore accidents are attributable to some form of human error, and 80% of these can be related to operational aspects of platform activities, e.g., 64% of high consequence accidents result from operational error.*[9] FLAIM identifies and permits the selection of known risk contributors to assess and quantify platform operational risks, placing heavy emphasis on safety management systems, their effective implementation, and the safety culture under which the platform is functioning.

FLAIM's Architecture

FLAIM can best be described as a QRA indexing methodology in which selected key factors relevant to fire safety and life safety are identified, assessed and assigned numerical (weighting) values. Risk contributing factors are thereby indexed and ranked using a weighting system algorithm, keyed to relative (comparative) risk, to yield a set of risk indexes, and an overall risk index for topsides facilities. For familiarity and ease of use, an academic letter grading scheme (A, B, C, D, F) based on a 4.0 grade-point scale was selected as the framework for assessing risk contributors. Refer to Appendix 2 for further detail on the specifics of the FLAIM algorithm.

Key topsides risk factors, identified on the basis of scenario analysis, expert opinion, and historical records, are selected and evaluated by the user together with provided or planned-for risk reduction measures. Life safety is assessed independently from fire safety, using risk factors specific to each, but accounting for their close interdependence. The adequacy of risk reduction measures and the overall platform Safety Management System (SMS) can be

assessed by calculating the RIRA and SAMSA indexes. These indexes reflect provision of risk mitigating and safety management status of the facility. They are combined with fire safety and life safety indices in order to arrive at an overall *topside risk assessment index*.

Figure 2, *Primary Building Blocks of FLAIM*, and Figure 3, *FLAIM Assessment Procedure*, illustrates the way in which risk modules were incorporated in FLAIM's assessment and indexing model and their relationship. Figure 3 serves as an overall "road-map" to FLAIM's methodology. Eight separate risk assessment modules, each of which yield individual risk indices used to calculate an overall topsides risk index, drive FLAIM's algorithm. These modules are shown in Table 1.

Table 1
FLAIM's Risk Assessment Modules

• General Factors Assessment (GEFA)
• Loss of Containment Assessment (LOCA)
• Layout and Configuration Assessment (LACA)
• Life Safety Assessment (LISA)
• Risk Reduction Measures Assessment (RIRA)
• Operations and Human Factors Assessment (OHFA)
• Safety Management Systems Assessment (SAMSA)

Risk Assessment Modules

The *General Factors Assessment Module* (GEFA) captures general safety-relevant information with regards to overall platform design and operations, e.g., platform size, age, configuration, general condition, etc. The GEFA module seeks to characterize the general nature of the platform or group of platforms for which the evaluation is being conducted. There are approximately 142 GEFA questions resident in FLAIM.

Loss of Containment Assessment (LOCA) addresses key risk contributors that lead to a release of production fluids or associated flammable and combustible process/utility fluids that may be in use on the platform. Unwanted leaks, spills and other types of releases of flammable production fluids, e.g., crude oil, condensate (natural gas liquids or NGL), natural gas, and to a lesser extent, ethylene glycol, diesel, aviation fuels, and other onboard liquid hydrocarbons, are the primary cause of major fires and explosions on offshore production platforms. Collectively referred to as loss-of-containment (LOC) events, such incidents are the generally attributable to one of three fundamental causes:

- equipment-material/mechanical failure
- human error-- both in design, operations, and maintenance
- external events (e.g., hurricane Andrew and (1982) Camille (1969))

Bea and Moore[10] have reported that the source of a majority of high-consequence offshore platform accidents (generally more than eighty percent) are attributed to compounded human and organizational errors. During the 1970's OCS records show that about one half to two thirds of all fires and explosions were attributed to equipment or mechanical failure, and the remainder to human factors-- principally errors of judgment.[11]

Equipment and material failures, however, are, in turn, most often rooted in human and organizational errors-- failure of the safety management system to either ensure the right material and equipment was initially installed for the service demands,

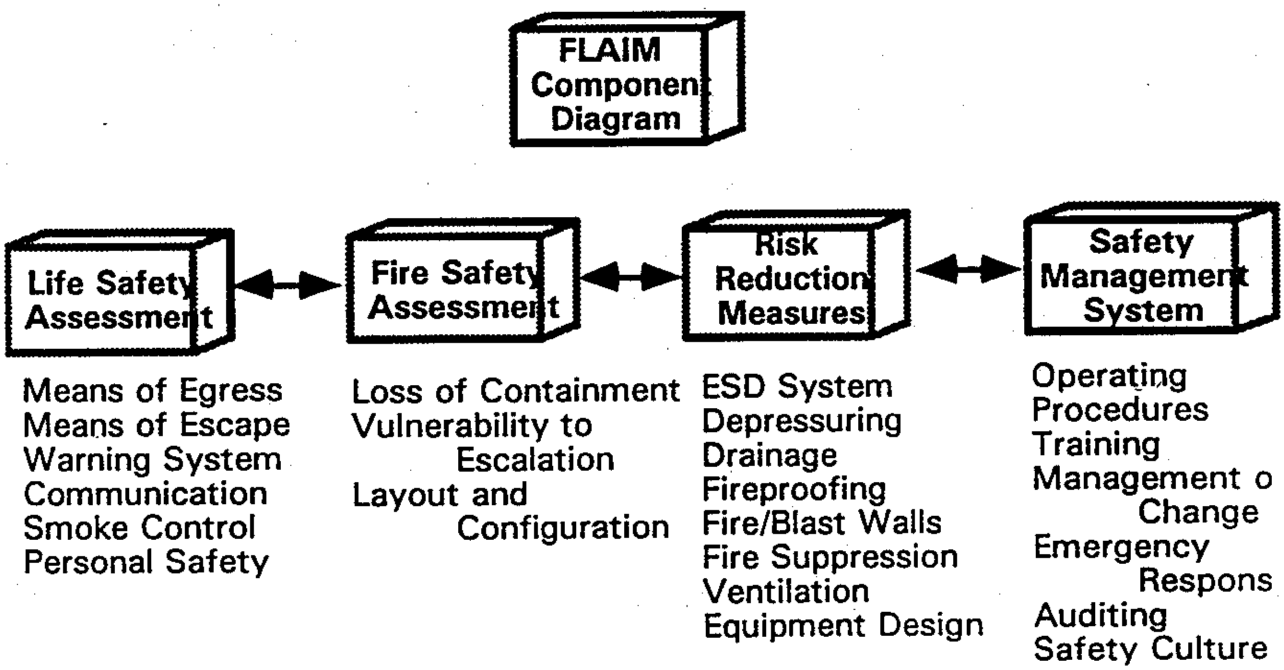


Figure 2

Primary Building Blocks of FLAIM

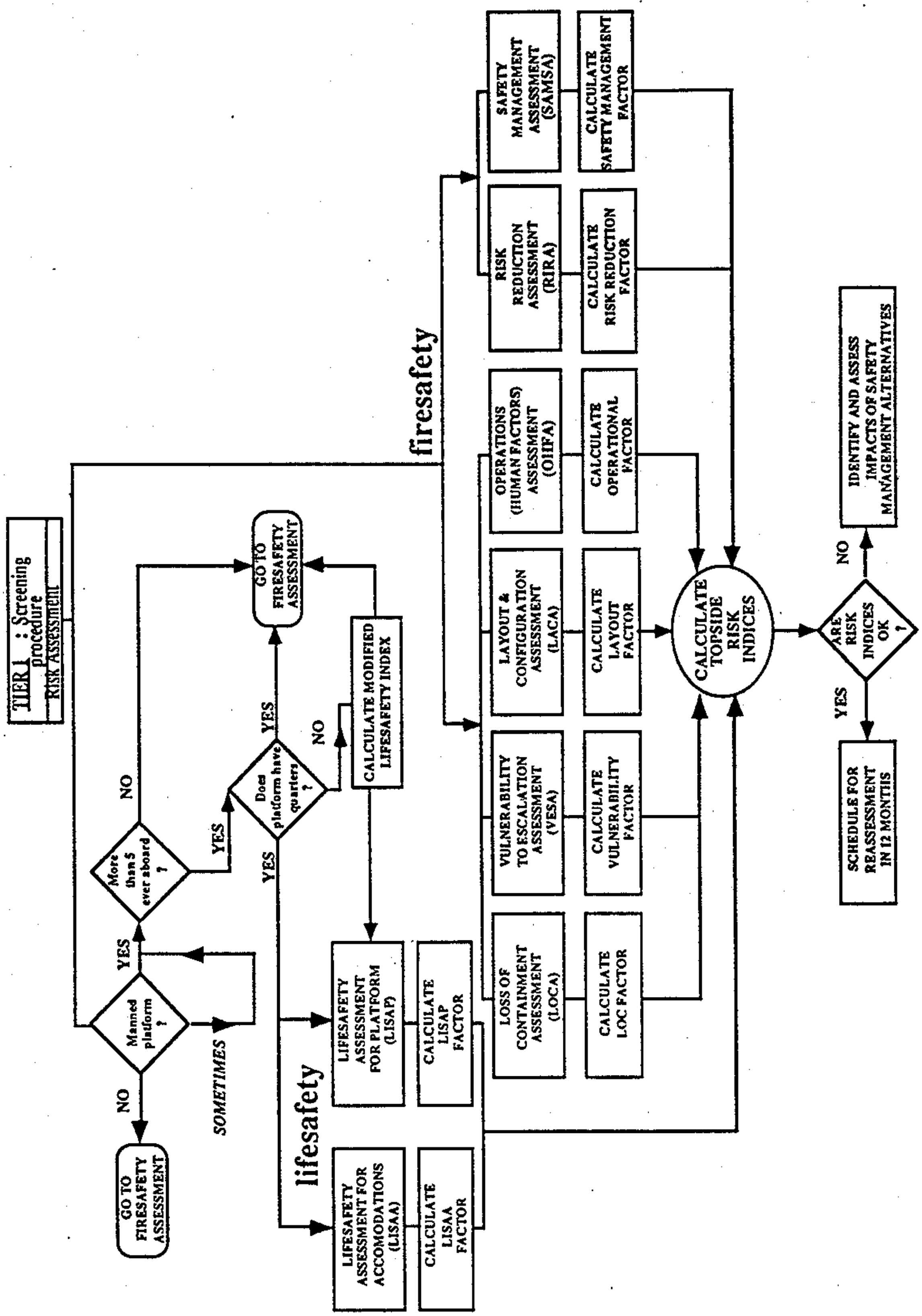


Figure 3

FLAIM Assessment Procedure

or to properly inspect, maintain, and test production equipment and systems. FLAIM is based on the premise that the most LOC events of significant consequence are not due to poor design, but rather stems from some form of human error,[12] e.g., personnel performing routine and/or non-routine tasks on pressurized hydrocarbon containing piping and equipment. For example, the CAI found that the act of opening a pressurized system for maintenance *to be the third leading cause of fatalities in the Gulf of Mexico (GOM) for the years of 1982-1986.*[8]

FLAIM's LOCA module has approximately 143 questions that cover four general categories of LOC events:

- *open-ended routes to the atmosphere, e.g., open drain or vent valve*
- *imperfections in or deterioration of equipment integrity*
- *external impact (this would include seismic events)*
- *deviations from design conditions*

The *Vulnerability to Escalation Assessment* (VESA) risk module accounts for those basic design and operational risk contributors that most influence a platform's vulnerability or susceptibility to event escalation and loss of control, i.e., cascading fire events. A platform's vulnerability to an initiating event escalating into a high consequence event depends on many inter-related factors. Factors included in the VESA module seek out those features or deficiencies in topsides design and operations that may contribute to the inability to:

- rapidly control, direct, and stop a LOC incident before ignition occurs,
- prevent ignition after a release has occurred,
- control the initial fire size and its resulting thermal impact on adjacent equipment andpiping, and
- prevent a further cascading of LOC events and structural/ functional deterioration.

Several subcategories of risk contributors were identified in the development of VESA leading to the development of over 240 questions. For example, included in the VESA risk module are the following groups of risk factors:

- *Equipment Risk Factors*- selected platform equipment and piping risk factors, including equipment type, operating pressure, installation practices, and known problem areas such as some piping design practices known to be highly susceptible to fire impact.
- *Special System Risk Factors*- selected platform system risk factors, including gas treating systems (glycol dehydration systems, etc.)
- *Ignition Risk Factors*- potential sources of ignition (fired equipment, electrical area classification, etc.)
- *Loss of Control Risk Factors*- process control and emergency shutdown systems.
- *Pressure Relief Capability*- pressure relief and depressuring (blowdown) capabilities, flare system design, vent system, liquid dump system if any.
- *Liquid Spill Control*- platform open and closed drain systems.
- *Vapor Control Provisions*- ventilation provisions for enclosed areas.
- *Emergency System Power Supply*- power and control system reliability (fail safe/ ups/redundant data highway/etc.
- *Thermal and Blast Robustness*- structural design considerations for thermal and blast impact.

Closely associated with these factors, but categorized separately for convenience, are layout and spacing risk factors, which comprise the *Layout and Configuration Assessment* (LACA) risk module. Offshore platforms are especially vulnerable to escalating fire scenarios due to the necessarily close spacing of high-pressured hydrocarbon containing equipment, e.g. potential fuel release sources, and potential ignition sources. Any LOC event or incipient fire that is not quickly detected and controlled is of great concern; especially on those normally attended platforms with accommodation facilities where life safety is at issue.

In general, it can be said that an offshore oil and gas production platform has most of the same fire safety concerns found in a typical onshore petroleum production facility, plus several additional risk factors that greatly increase the likelihood of escalation and personnel injury. LACA risk factors seek to account for the relative increased risk from certain layout and configuration design features, or lack thereof, that can significantly increase a platform's susceptibility to event escalation and injury to crew members. Approximately 130 LACA questions are included in FLAIM.

Shortly after the *Piper Alpha* accident, the U.S. OCS experienced the loss of a production platform from a fire which also took seven lives.[13,14] Human error was the direct cause for an uncontrolled release of hydrocarbons during a repair operation involving an 18 inch diameter gas riser.

The *Operational/ Human Factors Assessment* (OFHA) module focuses on what is termed "front-line" operational aspects of platform activities that directly contribute to increased risk levels. Changes in operations may routinely occur, such as periodic workovers, wireline operations or other downhole and topsides activities that, in turn, temporarily increase the overall level of risk on the platform until the job is completed. Errors involving operational activities are considered to constitute the single most important class of risk contributors leading to platform fires, explosions, and loss of life.

Many individual factors contribute to this problem, as identified by Moore and Bea,[15] including fundamental deficiencies in organizational aspects of the management structure. In OFHA, FLAIM seeks to identify those normally encountered production activities which may involve either an inordinate reliance/dependence on human judgment to avoid serious consequences (direct-link couplings), or activities in which the risk of error is compounded by the complexity or multiplicity of the tasks involved, e.g., multiple simultaneous operations such as drilling, producing and maintenance involving hot work or startup of equipment.

The OFHA risk assessment module contains approximately 167 questions covering five subcategories (Figure 4):

- *Maintenance and Repair Work* (MARW)
- *Multiple Operations Assessment* (MULOPS)
- *Operational Management of Change* (OPSMOC)
- *Operator Dependence and Response* (OPSDAR)
- *Operational History* (OPHIST)

For example, MARW addresses operational risks during times when maintenance and repair activities are taking place on the platform-- a time when many accidents

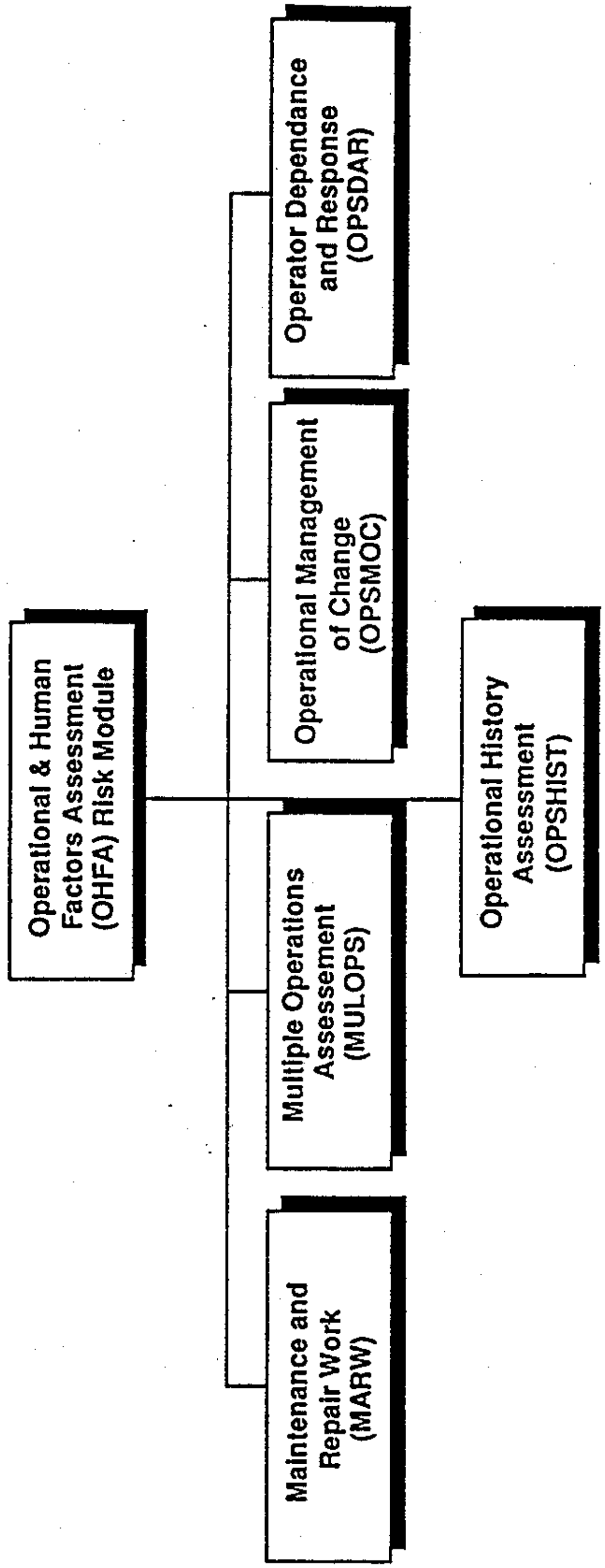


Figure 4

Components of OFHA Risk Module

happen. These activities include:

- major renovations/additions,
- turnarounds,
- routine maintenance/ repair work involving equipment entry, line-breaking,
- hotwork,
- pipeline pigging/ scrapper work downhole wireline work such as removing and testing storm chokes,
- workover operations, and,
- specialty work, such as pipeline riser retrofits/additions, control system modifications necessitating temporary bypass of safety shut-down functions, fire protection system work causing temporary impairment of the protection systems.

Often times MARW activities involve "line-entry" or "vessel-entry" procedures whereby the risk of an LOC event is increased. Normal process control elements, pressure relief valves, emergency shut down valves, and other control and safety provisions may be placed in a bypass mode or be removed from the system, thereby increasing the potential vulnerability to an initiating event. Hot work involving welding, cutting, grinding, etc. is also commonly included, resulting in increased ignition risk.

During MARW, reliance on human intervention and judgment is greatly increased over that required for normal operations--both from a preventative and a response standpoint. Simply put, more things can go wrong, and there is a greater dependency on worker judgment to make the correct decisions. However, there is also a greater risk of error during such activities, especially so when non-routine operations are involved, job complexities are increased, and work crews may be diverse and unfamiliar with the facilities or inadequately trained in the particular operations taking place.

The criticality of any particular MARW activity has been distinguished by Moore and Bea[15] into four major categories:

- *process critical*
- *process non-critical*
- *non-process critical*
- *non-process non-critical*

Process critical operations are considered to be those activities that involve vessel and/or line entry into hydrocarbon handling systems and equipment, e.g., operations posing an immediate risk of loss of containment. This includes all topsides process systems in which crude oil, natural gas, natural gas liquids (condensate) liquefied petroleum gases, and imported flammable liquids (methanol, glycol, aviation gasoline, etc.) are either processed, treated or otherwise handled/stored.

In FLAIM, process critical operations as a group is further subdivided into three subgroups:

- process critical - HIGH (pressure exceeds 500 psig)
- process critical - MODERATE (pressure above 100 but less than 500 psig)
- process critical - LOW (pressure 100 psig or less)

Process non-critical operations are considered in FLAIM to involve equipment and systems that handle non-volatile, combustible liquids (flash points above 140°F) at or near atmospheric pressure, such as fuel oil, diesel fuel, and lubricants.[16]

Non-process critical operations are those activities that impact a platform's ability to respond to an LOC event, including fire and explosion, or that increases the risk of

ignition should an LOC event occur. Any hot work activity not involving process critical activities would fall into this category. In addition, work that would require deactivation of any safety system, such as a fire or gas detection (as may be necessary during hot work), a fire pump, or a deluge system, is included herein.

Non-process non-critical work are considered in FLAIM to include those routine maintenance and repair activities, e.g., chipping and painting, that do not directly increase LOC risk or VESA risk, but by their very presence onboard, may add to platform supervisory and manpower demands, thereby contributing to overall increase in platform risk during simultaneous operations.

In OFHA, FLAIM recognizes that platform operational risk levels are time dependent, varying in both the long term, e.g., emerging safety deterioration trends, and in accordance with the nature of daily operations. MULOPS assesses the frequency and nature of those simultaneous activities that produce short periods of high operational risk.

Simultaneous operations are, in general, significant risk contributors depending on the nature and number of simultaneous operations occurring; this is especially true whenever downhole work is in progress on live (capable of flowing) wells. Large platforms may have several contractor crews engaged in different construction/maintenance activities at the same time, and while normal production and drilling activities are also taking place. This proved to be a significant factor leading to the *Piper Alpha* incident.[1]

MULOPS seeks to evaluate the relative risk of simultaneous multiple operations by establishing their nature, relative proximity to each other, and the frequency of their occurrence. Simultaneous operations during production may include drilling, workovers, wireline operations, refueling of onboard fuel supplies, off/onloading bulk supplies, pig launching and receiving, and various construction and maintenance activities, such as installation of riser safety valves.

The extent to which operational safety and the control of emergency situations depends upon operator response is an important risk consideration. Platform process systems designed with protective systems that automatically sense and initiate corrective actions to developing emergency situations are apt to be less vulnerable to errors in human judgment or lack of prompt operator response. OPSDAR seeks to evaluate the extent to which the platform design and operational scheme places reliance on operator response and judgment in order to safely shutdown topside systems and respond to LOC events.

Cognitive and sensory limits of operator response becomes increasing important in accident causation as the demands placed on operators increase. This problem is much the same faced by military fighter pilots who, compared with their immediate predecessors, have both a much greater array of sensory information to deal with as well as a much short time in which to arrive at correct decisions (due to higher flying velocities). The 1979 Three Mile Island nuclear plant accident was largely a result of a failure to properly sort out and recognize critically important information during the developing crisis scenario.[17]

OPSDAR uses a what-if scenario based approach to determine if emergency response plans are inadvertently placing too

much reliance on operators performing critically important tasks or otherwise overburdening platform personnel to ensure safety. For example, OPSDAR asks if platform blowdown system valves are automated or if operators must manually open them to depressure system piping; are platform deluge systems automatically actuated or must operators manually open local control valves; are deluge systems provided or are operators expected to fight fires manually with hand-hose lines, etc.

FLAIM includes a component intended to identify endemic operational problems as may be evidenced by reoccurring accident events. OPHIST addresses the operational history of the platform and seeks to determine if certain types of operational related events are more prone to occur. This information is intended to distinguish between appropriate changes that may need to occur and those that may have already been implemented to rectify the root cause of such events.

Consideration of risk reduction measures, such as fire and blast walls, fireproofing, explosion venting, fire suppression systems, e.g., both passive and active risk mitigation measures, are treated separately by the *Risk Reduction Measures Assessment* (RIRA) module. RIRA is the largest of FLAIM's risk assessment modules, containing nearly 300 questions about platform safety systems. FLAIM was specifically designed to allow independent assessment of risk reduction measures and their impact on the overall topsides risk index. In this manner, the relative merits of various mitigation measures can be tested in terms of a what-if cost/benefit analysis using the index as a discriminator for reaching safety target levels.

Aiding in the assessment and management of the risk of personnel injury and death is a primary focus of FLAIM. The *Life Safety Assessment* (LISA) module identifies and assesses those risk factors directly impacting personnel safety and welfare. LISA is further broken down into two sub modules: LISAP, *Life Safety Assessment - Platform*, and LISAA, *Life Safety Assessment - Accommodations*. If a platform is not provided with living quarters (LQ), such as platform on which the crew is rotated out each day or work-shift via helicopter or service vessel, FLAIM forgoes the LISAA component addressing accommodation facilities life safety and only evaluates the overall life safety features of the platform (LISAP).

Production platforms in the GOM have various size crews depending on the size and/or complexity of the platform. Many smaller platforms are normally unattended, whereas some platforms are normally occupied and may serve as central service facilities for nearby platforms. Unlike platforms in the North Sea, the crew size on platforms in U.S. waters is considerably smaller. The overall average number of personnel in attendance on GOM and Pacific production platforms is estimated to be 12 persons.[8]

LISAP is executed only if a platform is deemed to be "manned," e.g., a platform on which people are routinely onboard for more than twelve hours per day.[18] FLAIM incorporates occupancy criteria to trigger LISSA based on whether the platform has a LQ is actually and continuously occupied *by at least five persons*. This criteria is consistent with that adopted by the Panel on Seismic Safety Requalification of Offshore Platforms.[19] However, FLAIM recognizes that some operators may want to adjust this discriminator according to their own risk management policies. LISA

contains approximately risk assessment questions.

It is difficult to isolate all factors affecting life safety into a single risk module. Users of FLAIM will recognize the interdependence of the life safety assessment risk index on each of the other FLAIM assessment modules, and especially with regards to *Layout and Configuration Assessment* (LACA).

As already discussed, the Safety Management System (SMS) provides the means to integrate and execute those aspects of platform design and operations that directly and indirectly influence meeting safe operating goals. The *Safety Management System Assessment* (SAMSA) module contains those factors identified as being most prevalent in failures of the SMS. SAMSA seeks to assess the adequacy of management's ability to identify and respond to root-cause errors stemming from human and organizational factors, such as those leading to the *Piper Alpha* loss. Bea and Moore[20] have developed a taxonomy of human and organizational errors for marine related accidents. Preceded by early research by Paté-Cornell and Bea[21] and Reason[22], the HOE taxonomy addresses both error types and underlying causes. Thirteen error classifications have been identified by Bea and Moore that can be subdivided into four general categories, all of which are subject to external environmental influences.

In FLAIM's SAMSA risk module, factors identified in the HOE taxonomy (and not previously addressed in OHFA) are accounted in the subcategories: *Management Systems* (MASA), *Fire Preparedness* (FIPA), *Safety Training* (SATA), and *Management of Change Management Program* (MOCMAP), as illustrated in Figure 5. Note that MASA is further subdivided into four separate risk assessment sections: *Management Systems Safety Culture Assessment* (SCULA); *Organizational Responsibility and Resources* (OR&R); *Company Policies and Procedures* (POLPRO); and *Accountability and Auditing* (ACAU). Each of these components of SAMSA are considered to be interdependent and essential to achieving fire and life safety operating goals.

The four MASA components component of SAMSA form a synergism that are, in fact, a compilation of the (fourteen) essential elements of Total Quality Management (TQM) as expounded by Deming.[23] These elements are the sole responsibility of top management *and can only be carried out by top management*; they serve as direct indicators of management's awareness of and commitment to continued safe operations.[23]

The most essential element stressed by Deming[23] in his fourteen point approach to TQM is his last program element-- creating a structure and environment in top management that is conducive to continually *cultivating* and building upon on the other thirteen points, e.g., develop a "corporate culture" of quality that permeates down and throughout the entire organization. Deming believed in the need to develop a "constancy of purpose towards improvement" in which management's philosophy embraces bold (new) concepts aimed to empower the worker, creating organizational incentives encourage and reward self-improvement, eliminate work-er fear (to do the right thing), and remove barriers to improving quality and safety, e.g., imposed production quotas.

The SCULA section of MASA, together with OR&R (see below) and the other Management System components, identify

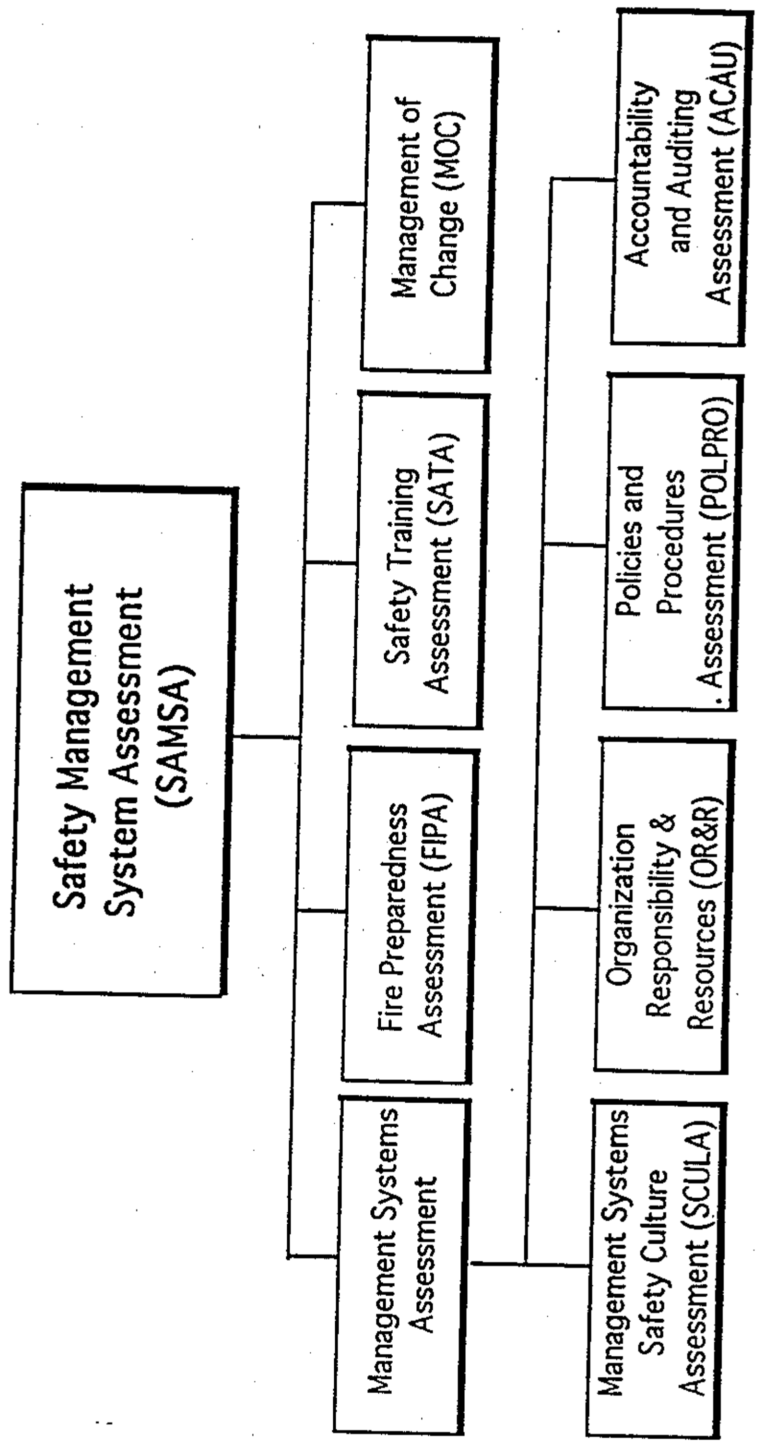


Figure 5
Safety Management System Assessment Module Components

and assess key indicators of management's awareness and commitment to these ideals.

As demonstrated by the current trend in the GOM, large offshore leaseholders (i.e., major oil companies) tend to sublet (farm out) older fields with declining production rates and rising maintenance costs to smaller operators who can continue to realize profitable operations due to lower overhead costs. The Marine Board's Committee on Alternatives for Inspection (CAI) of OCS Operations reported[8] that in a five year period in the mid-1980's, the number of operating companies with less than six leases in the GOM increased more than 325%. This trend is continuing today as many large companies are abandoning their operations in the GOM in favor of overseas opportunities.

The CAI found that the safety implications of this trend is undocumented, but there are certain characteristics of small companies that may affect safety risks:

- small operators typically have no inhouse safety staff and minimal technical engineering personnel to support field work or train field personnel in safe op erations,
- small operators are heavily dependent on contract labor and expertise, and normally provide little or no onsite operator supervision,
- many small companies have limited "worry-budgets" (a term coined by Professor R.G. Bea to denote resources for safety expenditures), and may tend to defer costly safety measures, e.g., be less risk-adverse than larger companies.

These considerations tend to make smaller operators more apt to adopt a "compliance mentality" towards safety rather than moving forward with an aggressive, proactive safety management system approach. *Organization Responsibility and Resources* (OR&R) seeks to identify weak safety culture environments by asking questions about: the company's safety and loss prevention staff relevant to the number of platforms being operated; its position in the organization and reporting authority; the percent of operating budget allocated to safety related activities, including training, maintenance, and testing of safety equipment; and the extent to which contract labor is employed to operate and maintain platforms, as well as the degree of supervision and training provided by the operator.

Another important component of Management Systems is the extent to which the operating company has committed its safety policies and practices to written instruction. Written instructions are the instrument by which safety policies, goals, and management's commitment are communicated throughout and beyond the organization, e.g., the means for articulation of the safety culture. FLAIM was developed with the recognition that attitude alone is not enough to elicit safe behavior.[24] Without written policy goals and explicit instructions on how to achieve those goals, the course of platform safety goes uncharted. Company *Policies and Procedures* (POLPRO) asks if the platform operator has a written policy establishing definitive safety objectives, goals, practices and the means to monitor, measure, and improve meeting safety targets.

The POLPRO element of MASA accounts for the status of written, up-to-date operating instructions for all topside systems and process components, including startup procedures, normal and temporary operations, emergency operations including emergency shutdowns (for each level of

shutdown), and black-start restarts from complete shutdowns of all platform operations and power sources. Individual startup/ shutdown and operating instructions for pumps, compressors, fired heaters, should be explicit to the machine in its "as-built" (as-installed) condition. As required by OSHA for onshore facilities, these procedures should contain information on occupational safety and health considerations.[25,26]

A written Safe Work Practices (SWP) Manual should cover many routine tasks including: line and vessel opening/ entry operations, lockout and tagout procedures, confined space entry, hot work and cutting operations, inerting and purging practices, heavy lifts and crane operations, sampling and sample connections, opening of drains and vents, use of personal protective clothing and gear, etc. The Permit to Work procedure should be clearly explained both in concept and in explicit requirements. In addition, accident investigation instructions and forms may be included in the SWP manual or provided as a separate document in the emergency response plan. These issues are addressed by the POLPRO component of MASA.

Emergency response plans are also another important element included in POLPRO. Most platforms will already have written plans for oil spills and for emergency evacuation as required by MMS and the USCG. POLPRO seeks to assess the adequacy of these procedures and asks about the frequency of emergency response drills and the provision of improving written plans based on feedback from lessons learned in rehearsals.

Successful implementation of the platform's safety management program depends to a large extent on the means used to measure progress in meeting safety goals and to effect improvements in program execution. Accountability is required to effect change and realize improvements. The ACAU element of MASA seeks to determine if the safety program is being effectively carried forward with the requisite level of management support and accountability necessary for meaningful implementation. This includes auditing of the safety assurance and written reports to management.

An important risk indicator in MASA is an operating company's "lessons-learned" program. ACAU asks the operator about the disposition of information collected in near-miss and accident reports. A proactive approach taken in analyzing and learning from operational experiences, and then following through by communicating this information and revising company practices accordingly, is one indicator of a strong safety culture. Conversely, compliance with accidents report requirements as mandated by MMS OCS Orders and committing the information to a file cabinet without further thought is clear evidence of "compliance mentality" as described by the CAI.[8]

The FIPA component of the SAMSA risk assessment module seeks to measure a operating crew's preparedness and ability to effectively deal with developing emergency situations. FIPA does not address hardware aspects of preparedness; these are accounted for in RIRA. FIPA is the complementary component to RIRA and evaluates the human and organizational factors deemed critical to controlling a developing fire scenario.

The extent of human intervention necessary to successfully control a developing situation depends to a large extent on the

platform design, its susceptibility to loss of containment events, provisions for automatic detection, control, and shutdown, and the platform's inherent vulnerability, or conversely, its robustness to resist thermal impact. There are two terms in "the equation" for assessing fire preparedness, each containing several variables.

The first term evaluates management's understanding of exactly what role the crew is expected to play in any given emergency situation. The assessment seeks to address issues of response expectancy with a view to determining whether or not an unrealistic reliance and dependency has developed on a crew's ability to respond.

For example, identification of critical manual tasks necessary for successful fuel-source isolation in a LOC event, when compared to concurrent demands for fire-fighting, communications, and general platform shutdown, may show an inordinate dependence on human response in some scenarios. Quite often, emergency demands placed on crew members tend to evolve and change in response to platform modifications and expansions. The cumulative effect may exceed reasonable response expectancies, but go unrecognized for lack of an emergency operability study.

The second term in the fire preparedness equation addresses the crew's preparedness and capability to carry out those essential demands placed on it under various emergency scenarios, assuming the demands are reasonable as evaluated above. This requires and assessment of the crew's knowledge and understanding of what is expected for a given situation, their ability and willingness to effect their duties, and the capability to demonstrate this through hands-on hypothetical training exercises for emergency situations.

For example, the operators at the Three Mile Island Nuclear Plant had been trained that the pressurizer on the pressurized water reactor was a valid representation of coolant inventory. Their training had not considered the possibility for a leak on top of the pressurizer, e.g., *their training model for emergency events failed to consider all possible event causes and consequences*. When the pressurizer leak occurred, the operator's diagnosis of the problem was based on an inaccurate model of what was actually happening-- they interpreted a rise in pressurizer level as an indication of excessive coolant in the system, which caused them to dump coolant, eventually leading to a meltdown.[27]

The *Safety Training Assessment* (SATA) component of the SAMSA risk module is intended to evaluate the overall level of formal personnel training and operator qualifications. Recognizing that human and operational error is the primary cause of offshore accidents, the adequacy of training at all levels throughout the organization is assessed-- both from an operational standpoint and from a risk aversion/cultural standpoint.

Well trained operators, inspectors, maintenance personnel, and supervisors are essential to workplace safety. Further, it is recognized that training must necessarily be viewed as a dynamic process, accounting for an ongoing effort to maintain personnel awareness and cognizance of a safety culture. Beyond this however, the overall attitude and culture of management must necessarily be assessed with regard to the inherent reward system of the organizational structure.

Training sessions must not only cover normal operating procedures and emergency response planning, but should also

include safe work practices. This should include routine review of the work permit system requirements as well as specific training in each work practice, e.g., hot tapping, hot work, lockout/tagout, etc. If contract personnel are used to perform MARW activities, SATA seeks to determine if the contractor's personnel are adequately trained and qualified to perform their assigned duties, as well as being trained for emergency response.

The goal of risk management programs is to manage how risk may change over the operational lifetime of a platform, e.g., *the key to successful risk management is successfully managing change*. Both physical changes and personnel changes, and operational changes can greatly impact fire and life safety risks. In the recent past, however, the management of change has not been generally recognized as a factor that must be continually and systematically managed.

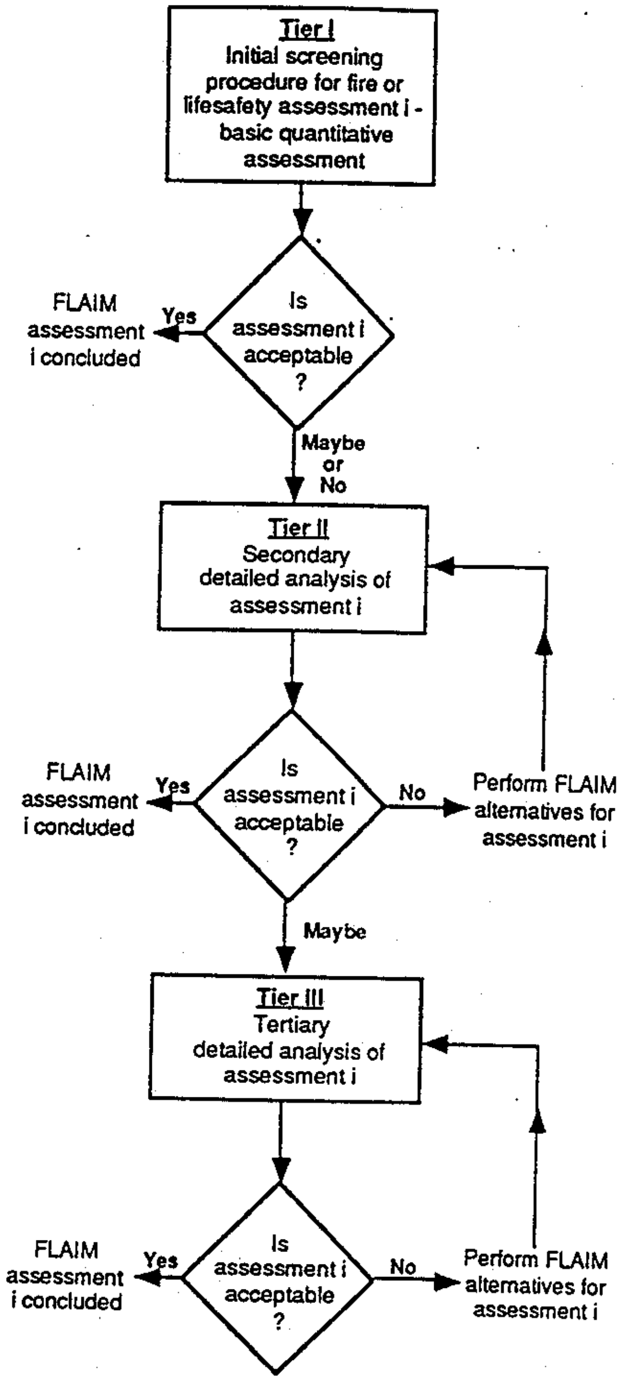
In the *Management of Change Management Program* (MOCMAP) section of the SAMSA risk module, FLAIM asks if the prerequisite elements of a MOC management program, as identified by API RP 75,[28] are established and implemented in written procedures. This should include the requirement for a hazards analysis of the safety, health and environmental implications of the proposed change, including its direct local impact and global ramifications to the overall risk level of the platform. Such an evaluation may be performed by using FLAIM's methodology to assess these impacts.

Screening Platform Risk Factors

FLAIM has been designed to accommodate the user in several ways. First, it allows the user to examine platform fire and life safety issues in increasingly higher degrees of analysis (see Figure 6). The screening procedure follows the same general procedure established for structural requalification of offshore platforms proposed by Williamson and Bea.[29] Tier 1 is the initial screening procedure designed to assess the general state of platform risk with regard to both level of consequence and the likelihood of incident occurrence. Tier 1 consists of sets of questions that are considered to be basic but, at the same time, the most important questions relevant to overall platform operations and potential for loss. Depending of the results of initial screening, a Tier 2 or Tier 3 screening may be warranted for any given assessment under consideration.

Tiers 2 and 3 consists of supplemental questions intended to further delineate the state of operations and the relative risk-state of the platform. Tier 2 and 3 questions have been weighted at correspondingly lower values than those of Tier 1, and are increasingly more comprehensive and detailed. Consequently, as FLAIM is applied in higher screening levels, a more detailed level of understanding and assessment of platform risk is derived.

Throughout the process, the user(s) performs two vital roles. First, the user checks and verifies the applicability of questions identified for each screening level in accordance with user preferences and experiences, e.g., FLAIM is interactive in both its content and in its application. Second, input to FLAIM is intended to represent a consensus of opinion, derived from a collective response from those individuals most familiar with the design and operation of the platform and its present exposure to loss. In this sense, FLAIM draws on industry's present familiarity with the HazOp procedure, but without the cumbersome technical analysis procedures demanded by



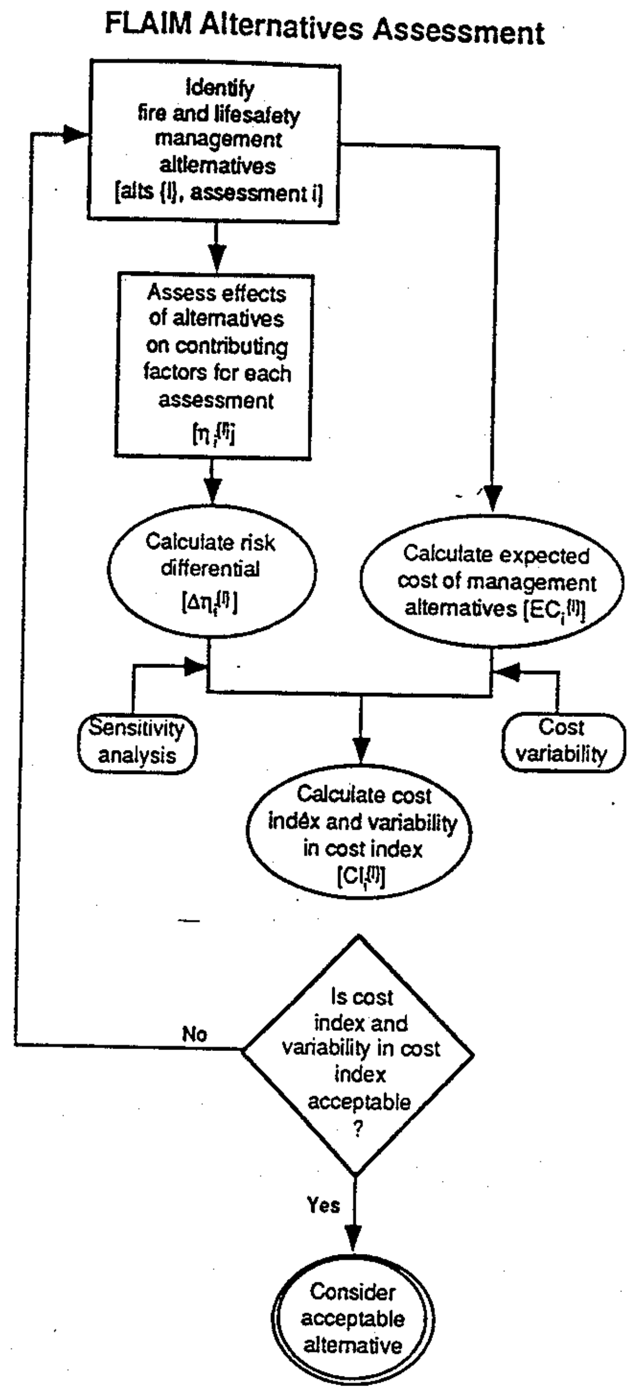


Figure 6

FLAIM Screening Procedure

the HazOp.

Questions have been developed reflecting offshore fire and life safety experiences, and professional expertise, case histories, industry recommended practices, regulatory requirements, and other relevant sources. All together, FLAIM contains over thirteen hundred questions which users can chose from and add to during the calibration procedure. Some questions have been identified as "red-level" questions, e.g., considered appropriate for inclusions regardless of platform specifics. These questions are automatically incorporated on the assessment worksheets unless the users intentionally deletes their entry. Default weightings for the questions have been assigned without regard to regional factors or unique considerations that may significantly influence the evaluation. In recognition of this, FLAIM has been specifically developed for the users to modify the weighting values and suggested tier level in order to account for unique design operating conditions. This is done during the initial calibration procedure by the user group.

Calibrating the Worksheets

Much like a hazard and operability study, FLAIM draws on the experience and knowledge of the users to calibrate the worksheets at the beginning of an assessment. Once the worksheets have been calibrated however, data input can be assigned to one or more persons e.g., the similarity to a HazOp session ends-- the are not laborious group meetings needed to evaluate platform conditions.

The user group's tasks are 1) to reach a consensus on the level of detail warranted in the screening process (e.g., select an appropriate Tier level for the review), 2) select the appropriate questions relevant to the platform under consideration, 3) determine if any questions have a higher or lower relative importance (weighting value), and 4) for those questions in which a numerical range is involved, assign a value range to each answer selection provided in the question. The user(s) may also decide to modify existing questions or add new questions in order to customize the assessment process to conform with platform conditions and needs.

Once the calibration procedure has been accomplished, the actual assessment process may be completed either onboard the platform or in the field office by one or more persons knowledgeable about platform design and operations.

Performing the Assessment

The session begins with the meeting facilitator loading and opening the FLAIM software package. The first window that appears after FLAIM is started is "Platform Identification Information." The user enters the platform's name, its location, block, lease numbers, etc. Next a window will appear asking whether a new platform assessment or modification of an existing platform assessment is to be performed. For example, for a first-time assessment the user clicks on "NEW;" FLAIM was designed to permit routine evaluations on a scheduled basis in order to detect symptomatic deteriorating trends as they may develop.

When the user reaches the "Fire and Life Safety Assessments Options" menu after inputting the preliminary information asked for, eight assessment choices are available corresponding to each assessment modules as described in FLAIM. As already described these are:

- *General Factors Assessment* (GEFA)

- *Loss of Containment Assessment* (LOCA)
- *Vulnerability to Escalation Assessment* (VESA)
- *Layout and Configuration Assessment* (LACA)
- *Operations and Human Factors Assessment* (OHFA)
- *Risk Reduction Measures Assessment* (RIRA)
- *Life Safety Assessment* (LISA)
- *Safety Management Systems Assessment* (SAMSA)

For a new assessment, the user begins with *General Factors Assessment* (GEFA), and then continues down the list until such time that all information has been inputted into each assessment module. FLAIM then calculates the overall fire and life safety index once all of the appropriate assessment modules have been completed, and also determines the difference any changes may make by calculating a differential risk index.

Summary and Conclusions

The cause and consequence of fires and explosions on offshore production platforms are extremely complex and highly dependent on events that may have only indirectly related precedents. Lack of comprehensive and meaningful statistical data and models on offshore system failures, human error, organizational factors, consequence analysis, etc. create a large uncertainty inherent in applying any predictive hazard analysis technique to a production platform. .FLAIM has drawn on many resources in an effort to combine deterministic and heuristic considerations into a unified approach for managing offshore fire and life safety risk. While FLAIM may be particularly helpful in identifying important considerations overlooked in the risk assessment process, it ultimately relies on the subjective probability and judgment of its users' input to assess relative states of risk.

It has been observed[30] that objective probability, based on statistical data, is believed by everyone except by the statistician; whereas subjective probability, based on experience and judgment, is held in contempt by everyone except the evaluator performing the analysis. The key to successful use of FLAIM lies in the selection and training of the assessors to ensure consistency and uniformity of evaluations. FLAIM was designed to permit quantification of a mixture of qualitative and quantitative responses to selected assessment questions. If there is not a clear understanding of what is meant by a particular qualitative descriptor, e.g., *high, frequently, low*, etc., then the validity of that input response is suspect.

FLAIM's design has sought to minimize this problem insofar as possible by frequent use of multiple choice questions that have specified a value range selection. However, other questions necessarily ask for the users' general assessment using non-defined qualitative descriptors. To facilitate a general understanding of such terms and reduce possible errors due of a risk-communication nature, it is recommended that each user group define criteria for applications of these qualitative descriptors as part of the FLAIM worksheet setup process.

As part of FLAIM's implementation plan, it is recommended that all user group-leaders undergo a basic leadership orientation and training course (i.e., similar to a HazOp leader training course) that addresses, *inter alia*, issues of risk communication and the meanings of commonly used descriptors and criteria employed to characterize risk

and the risk assessment process. User workshops designed to educate assessors and surveyors in application of the FLAIM software package is also suggested.

The quantification of human and organizational error in the Maritime industries has only recently begun to receive the serious attention of researchers. Bea and Moore[31] have made significant progress over the past three years in developing quantitative models and methodologies for examining human and organizational errors (HOE) in the operation of marine systems. It is now generally recognized that only through improving the characterization and management of HOE risk factors can further strides be made to improve the offshore safety record. In this regard many opportunities exist for further research and development.

At present, there is insufficient data to develop meaningful objective probabilistic forecasts for offshore fires and explosions. It is believed that FLAIM can provide a basis for development of such data if used to assist accident and near-miss investigations. In this regard, it is recommended that further research be devoted towards developing a protocol and software interface with FLAIM to facilitate capturing vital information on platform accidents and near-misses. It is believed that such information could easily be incorporated into the existing structure of FLAIM's architecture in order to provide interactive access to new or existing proprietary databases.

Continued work is needed in refining and optimizing FLAIM; as mentioned in the introductory chapters, this will no doubt occur as part of its natural evolution through increased usage. However, it is also believed that a demonstration and validation study should be performed in the near future that involves several representative production platforms from different geographical locations, e.g., GOM, Pacific Region, GOA, etc. In this manner, FLAIM's utility and adaptability can be effectively tested and improved. In this regard, more attention is also warranted for developing a formal technique for updating FLAIM with a view towards continually improving reliability with each successive use.

The addition of an assessment module addressing life safety risk factors specific to those platforms handling hydrogen sulfide containing production fluids would be useful. In addition, further development of an economic analysis component of the software package would assist users in the decision making process.

One area of further research having immediate interest is the possibility of combining FLAIM with the Human and Organizational Error Data Quantification System (HOEDQS) developed by Moore.[32] It is believed that as research progresses on identifying and characterizing human and organizational errors in meaningful ways, an immediate benefit will be realized in decreased loss rates and improved safety awareness. Combining the best features of FLAIM and HOEDQS would also serve to promote further research in the integration of human and organizational considerations in the application of the traditional engineering disciplines. Such research is considered essential in order to arrive at truly multi-disciplinary systems engineering solutions to the continuing problems of safe operations offshore.

How to Order FLAIM

Copies of FLAIM© text and software are available to researchers through UMI Dissertation Services. Call 1-800-521-0600,

extension 3879 for further information.

Appendix 1: Valid Precedents - Risk Indexing Methodologies

FLAIM was developed with specific regard to the CAI's criterion for "valid precedents," and builds on concepts that have been successfully employed by major onshore petrochemical companies and fire safety authorities for over 25 years, *using risk indices to measure and assess life safety and fire safety risks*. The application of these techniques to offshore platforms was guided by principles established by the National Fire Protection Association for applying system safety techniques as a means to reach safety goals.[33]

Various indexing methodologies for safety assessment have been in use for many years, having their origin in the insurance underwriting industry where they are sometimes referred to as fire risk assessment schedules. Some of these approaches are well established and have been applied to the petroleum/ petrochemical processing industries,[34] such as the Dow Fire and Explosion Index[35] as discussed below. Other indexing schemes, such as Muhlbauer's approach[36] for pipelines, are relatively new and remains to survive the test of historical validation. Several of these methodologies were reviewed in formulating FLAIM's model, including:

- The Dow Fire and Explosion Index[35]
- The Mond Fire, Explosion, and Toxicity Index [37,38,39]
- Purt's Method[40]
- Gretener's Method[41]
- Nelson's Fire Safety Evaluation System[42]
- Muhlbauer's Risk Management Index for Pipelines[36]
- DNV/International Loss Control Institute's International Safety Rating System[43]

Professional judgment, historical records, past experience, and in some cases predictive hazard evaluation techniques (e.g. event tree analysis (ETA), Hazard and Operability Studies-- "HazOps," etc.) are used by indexing methodologies to identify and select key variables (risk contributors and risk mitigators). These are then combined by using various algorithms to yield risk indices indicative of the state of the facility and its management system. An overall risk index can be also generated to compare different facilities in a relative manner, providing insights to judgments on risk preferences and priorities, as well as facilitate the cost-benefit analyses for risk mitigating measures.[34,44]

The Dow Fire and Explosion Index (F&EI) is perhaps the oldest and most widely recognized hazardous facility oriented indexing methodology in use today. The first edition of the Dow's *Fire & Explosion Index Hazard Classification Guide*, published nearly thirty years ago in 1964, was a modified version of an insurance industry methodology, the *Factory Mutual Chemical Occupancy Classification Guide*. Over the years, refinements in Dow's indexing methodology and improvements in quantitative correlation were made to arrive at the current edition.

The Dow F&EI seeks to quantify the expected damage of potential fire and explosion incidents in realistic terms, identify equipment that would likely contribute to the initiation or escalation of an incident, and to communicate the fire and explosion risk potential to management. The quantitative measures employed in the analysis are based on historic loss data, the characteristics of the materials being handled, and the extent to which loss prevention practices are applied in the facility under consideration. The Dow F&EI is widely used as an aid to the selection of fire preventive

and protective features, and is a well proven method.[45]

The Dow F&EI has proven to be an effective tool for evaluating hazards during process development, site selection, and plant layout, and can be used as a model for developing other risk screening techniques for prioritizing and ranking plant risks.[44] Dow Chemical believes that their fire and explosion indexing methodology is, in fact, equivalent to those cited by OSHA in the process safety management regulations (29CFR1910.119) and Dow will reportedly continue to rely on this approach to satisfy federal process hazards analysis requirements.[46] This viewpoint was taken as an important consideration in carrying forward the development of FLAIM.

Watt has observed that fire risk schedules (indexes) have the advantage of high utility due to their relative ease of preparation, but may lack validity due to the unspecified nature of the selection of variables and their relationship.[47] Watt opines that a desirable objective is to generate a schedule (i.e., indexing methodology) by the selection of variables in a manner that is rational, logical and inherently reproducible to achieve a means or risk evaluation sufficient in both utility and validity. It is with recognition of this objective that FLAIM was developed.

FLAIM's was designed to avoid such criticism insofar as possible by carefully establishing the relationship of the selected variables, the historical record, and the chosen risk factor's relationship to topside risk using established logic networks, vis-á-vis, the NFPA Fire safety Concepts Tree.[33] However, as exemplified by the Dow F&EI, FLAIM's utility must ultimately be subjected to demonstration testing and feedback in order to achieve a comparable consensus.

In this regard, FLAIM's development included reviewing and assessing risk factors identified in various studies of petroleum handling facilities, such as in the study entitled *Facility Assessment, Maintenance and Enhancement* (FAME),[48] which was sponsored by the U.S. Minerals Management Service (1992) in response to the Marine Board's CAI recommendation calling for improved accident databases. FAME's work included developing a listing of several key topside risk factors, but stopped short of the goal for developing an assessment methodology.

In a sense FLAIM may be viewed as the uncompleted forth part (Task 4) of the FAME study, e.g., the development of a methodology to perform a requalification audit of a facility and its operation, which reportedly was not pursued for lack of funding.

Appendix 2: The FLAIM Algorithm

FLAIM's input data is requested in one of three primary forms: (1) binary, (2) qualitative letter grades, and (3) numerical values. The following is an explanation of these input values.

Binary Input Data

The binary value system (β_{ij}) is presented by answering "Yes" or "No" (or "Good" or "Bad") to the presented questions. The input value returns a value of 0 or 1 dependent upon the assignment of the value to the answer (Equation 1). Any question that is to be answered "Yes" or "No" in the FLAIM spreadsheet program is followed by - "(Y/N)."

$$\beta_{ij} = \begin{cases} 0 \text{ if "Yes"} \\ 1 \text{ if "No"} \end{cases} \text{ or } \beta_{ij} = \begin{cases} 0 \text{ if "No"} \\ 1 \text{ if "Yes"} \end{cases} \quad (1)$$

for question i, assessment j.

Letter Grades

The grade point structure follows along the line of the grade point structures used in academia. The grade points range from "A" to "F" and are assigned numbers based upon the same 4.0 point grading system used in many academic grading schemes. The algorithm automatically assigns a numeric value to the grade point input provided by the user in the spreadsheet (see Table A2-1). Questions that directly use the grade point scheme in the spreadsheet are provided with a short description of what constitutes the selection of that grade. The grades are represented by $0 \leq \eta_{ij} \leq 4$ (risk assessment i, question j).

Numerical Values

Quantitative values (such as barrels of oil per day, millions of standard cubic feet of gas produced per day, size of operating crew, etc.) are numeric value inputs. The units prescribed for each input value is provided at the end of each question. This information is used in the assessment of the relative overall consequence level of the platform, as well as for evaluations of specific risk contributing factors.

FLAIM Weighting Structure

To maintain consistency with the grade point scheme, all default input values are considered to range between 5.0 and 1.0. This is equivalent to the concept of the number of "units" that an academic course is worth. The greater the unit value, the greater the relative importance of that factor to the grading scheme.

Table A2-1
Grade point scheme for platform risk factors and corresponding numeric values

A - "Excellent" condition of the risk contributing factor upon the platform fire and/or life safety (4.0)
B - "Good" condition of the risk contributing factor upon platform fire and/or life safety (3.0)
C - "Fair" condition of the risk contributing factor upon platform fire and/or life safety (2.0)
D - "Poor" condition of the risk contributing factor upon platform fire and/or life safety (1.0)
F - "Bad" condition of the risk contributing factor upon platform fire and/or life safety (0.0)

The weighting structure of FLAIM's algorithm has two types of value inputs (ω_{ij}) (risk assessment i, question j): (1) direct input value assessment of weighing values, and (2) indirect input value assessment, e.g., values generated as part of the algorithm. Direct inputs are provided by the user's assessment of the relative importance of that particular factor to fire and life safety on any given platform. For example, the relative importance of the ability of personnel to escape via the sea for a platform in the Gulf of Mexico (GOM) may be considered a more vital aspect of the overall risk management plan than that of a platform located in the Gulf of Alaska (GOA).

Conversely, in areas where weather can be extreme, "safe havens" for personnel may create a greater need (and importance) for firewalls with high levels of fire endurance since escape by water may not be a viable option.

Indirect value assessments can be made

through summing the binary input values (β_{ijk}) which are made up of sets of sub-questions. There can be between 2 and 23 sub-questions dependent upon the importance of the factor in question to fire and/or life safety.

Indirect value assessments are also functions of the numeric input values. These values are used to weigh the relative importance of fire and life safety risk. For example, if there is a small crew contingent aboard the platform, there is a smaller overall risk of injury or loss of life to personnel than if there was a large operating crew. Or, for example, production rates (high or low) may have a great impact upon the loss of containment risk.

The FLAIM Algorithm Value Structure

The primary algorithm structure is in the form shown in Equation 2. This general algorithm structure is similar to that of the academic grading scheme. The *grade point average* (GPA) is determined by summing the product of the grades and credits for each course (total of *p* courses) and dividing by the total number of credits. This value is the GPA.

Table A2-2 summarizes the grading structure used for each value assignment type.

$$\eta_j = \frac{\sum_{i}^{n} \omega_{ij} \eta_{ij}}{\sum_{i}^{n} \omega_{ij}} \qquad (2)$$

Numeric Value Range Assignments

The numeric value assignments have a predefined "value range" that determine the grading structure. Single-question numeric value assignments have direct value assignments. Multiple-question numeric value assignment questions use an averaging of values obtained from each sub-question. As already explained the user is asked to define the range values that determine the grading structure based on the particular platform design and operation circumstances under scrutiny; FLAIM has been intentionally designed to allow either the user, or the consensus of a user's group,[49] to "calibrate" the risk assessment process.

Binary Value Assignments

The binary input value assignments are given dependent upon whether the question has a positive or negative impact upon fire and life safety values. Multiple-binary value assignments are averaged over the sub-questions to provide an overall grade for that particular question.

Grade Value Assignments

Single grade value assignments are based directly upon the A-F structure described in Table A2-2. The multiple sub-question value assignments use the A-F grading scheme. Similar to the numerical and binary multiple sub-question value assignments a mean grade value is used by averaging the grade over the number of sub-questions.

Question Weighting Assignments

In accordance to Table A2-3, default values are assigned to the weight of each question dependent upon the level of the assessment. Certain FLAIM questions have already been pre-determined as suggested red-flag or "red-level" questions. These questions have been deemed to be particularly important to the safe operations of any offshore platform. Weighted value assignments for these factors are assigned by the user; those questions identified of particular importance may be assigned weighting values greater than those assigned at the Tiers 1-3 levels. However,

Table A2-2: FLAIM Algorithm Value Assignments

Numeric value assignments	Binary value assignments	Grade value assignments
Single question value assignments	**Single question value assignments**	**Single question value assignments**
$\xi_{ij}(x) = \begin{cases} 4.0 & x < x_{ij}^1 \\ 3.0 & x_{ij}^1 \le x < x_{ij}^2 \\ 2.0 & x_{ij}^2 \le x < x_{ij}^3 \\ 1.0 & x_{ij}^3 \le x < x_{ij}^4 \\ 0.0 & x > x_{ij}^4 \end{cases}$	$\beta_{ij} = \begin{cases} 4.0 & \text{"positive impact"(Y / N)} \\ 0.0 & \text{"negative impact"(Y / N)} \end{cases}$	$\varepsilon_{ij} = \begin{cases} 4.0 & \text{if grade"A"} \\ 3.0 & \text{if grade"B"} \\ 2.0 & \text{if grade"C"} \\ 1.0 & \text{if grade"D"} \\ 0.0 & \text{if grade"F"} \end{cases}$
Multiple sub-question value assigments	**Multiple sub-question value assigments**	**Multiple sub-question value assigments**
$\delta_{ijk}(y) = \begin{cases} 4.0 & y < y_{ijk}^1 \\ 3.0 & y_{ijk}^1 \le y < y_{ijk}^2 \\ 2.0 & y_{ijk}^2 \le y < y_{ijk}^3 \\ 1.0 & y_{ijk}^3 \le y < y_{ijk}^4 \\ 0.0 & y > y_{ijk}^4 \end{cases}$	$\rho_{ijm} = \begin{cases} 4.0 & \text{"positive impact"(Y / N)} \\ 0.0 & \text{"negative impact"(Y / N)} \end{cases}$ $\rho_{ij} = \frac{1}{m}\sum_m \rho_{ijm}$	$\gamma_{ijn} = \begin{cases} 4.0 & \text{if grade"A} \\ 3.0 & \text{if grade"B"} \\ 2.0 & \text{if grade"C"} \\ 1.0 & \text{if grade"D"} \\ 0.0 & \text{if grade"F"} \end{cases}$
$\delta_{ij} = \frac{1}{k}\sum_k \delta_{ijk}$		$\gamma_{ij} = \frac{1}{n}\sum_n \gamma_{ijn}$

Table A2-3: Value Weighting Assignments According To Relative Importance

Relative Importance of Assessment to Fire or Life Safety	Assessment Level Assignment	Default Weighting Value Assignment - ω_{ij}*
Red-Level	**Initial**	**Assigned by users**
High	**Tier 1**	**5 (5-4)**
Moderate	**Tier 2**	**3 (3-2)**
Low	**Tier 3**	**1 (2-1)**

* Values in parentheses are value assignment ranges for each assessment level.

FLAIM also allows the user to reassign the suggested default value of any selected question. If the assigned value exceeds the Tier 1 level value of 5, FLAIM automatically designates the question to a "red-level" status.

Factors from Tier 1 (initial screening) assessments are assigned the highest weighted values since they account for the most important contributing fire and life safety factors specific to the platform being assessed.[50] More detailed Tier 2 and Tier 3 questions are weighted correspondingly lower to reflect their *relative importance to overall* fire and life safety.

Though default values are assigned, FLAIM allows users to modify the value to reflect their preferences and experiences. Should a Tier 2 or Tier 3 factor be assigned a higher weight value comparable to that at a level higher than originally assigned, the user may reevaluate whether that contributing factor should be reassigned to a higher Tier level. At the user's discretion, these values may be changed to account for the relative importance of the question as determined by a consensus of the user group performing the analysis.

Individual FLAIM Assessment Grades

Equation 2 is used to determine the GPA for any assessment j (η_{ij}). As shown in Equations 3 and 4, the grade value is assigned according to the question type. Each question is weighted according to its Tier level assignment except for the critical level where the weighted value is assigned by the users (τ_{ij}).

FLAIM's Overall Fire and Life Safety Index

To determine the platform's overall Fire and Life Safety Index a weighted sum of all risk assessment modules is made to determine the index value. Equation 5 is

$$\eta_{ij} = \begin{cases} \xi_{ij} & \text{if question i , assessment j is single question numeric} \\ \delta_{ij} & \text{if question i , assessment j is sub- question numeric} \\ \beta_{ij} & \text{if question i , assessment j is single question binary} \\ \rho_{ij} & \text{if question i , assessment j is sub- question binary} \\ \varepsilon_{ij} & \text{if question i , assessment j is single question grade value} \\ \gamma_{ij} & \text{if question i , assessment j is sub- question grade value} \end{cases} \qquad (3)$$

$$\omega_{ij} = \begin{cases} \tau_{ij} & \text{if "Red-Level"} \\ 5 & \text{if Tier1} \\ 3 & \text{if Tier2} \\ 1 & \text{if Tier3} \end{cases} \qquad (4)$$

the weighted assessment used to calculate the overall Fire and Life Safety Index.

The weighted assessment procedures allows the user to take into account the overall relative importance on any single risk assessment module relative to each other, e.g., how GEFA, LOCA, VESA, LACA, OHFA, RIRA, LISA and SAMSA should be considered on a comparative basis.

$$GPA_{overall} = \text{Overall Fire and Safety Index} = \sum_{j=1}^{5} \sigma_j \eta_j \qquad (5)$$

where,

$$\sum_{j=1}^{5} \sigma_j = 1 \cdot$$

FLAIM calculates the overall Fire and Life Safety Index using equal weighting among all risk assessment modules as a default condition. This is in recognition of the need to assess each module's relative weighting value based on the particular platform under consideration; not because of any implied level of equivalency. For example, on newer platforms the risk of LOC events due to mechanical failure may be judged to be relatively low, while the likelihood of a human error caused accident may be high due to simultaneous drilling, production, and construction activities. In this regard, it is important for the user to establish a uniform application of weighting values among groups of similar platforms in order to derive meaningful results from this procedure. It is suggested that operators can meet this objective by establishing their own application criteria that will ensure consistency and uniformity in the application of FLAIM.

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50 The basic difference between red-level and Tier 1 questions is that the former are considered to be questions which are generally important to the operations of <u>all</u> offshore structures, whereas Tier 1 level questions may be <u>specific</u> to the platform being analyzed.