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FINAL REPORT

Updates to Fault Tree Methodology and Technology for Risk Analysis
Chukchi Sea Sale 193 Leased Area

BOEM Contract Number M11PC00013

October, 2014

By

Bercha International Inc.
Calgary, Alberta, Canada

U.S. Department of the Interior
Alaska Outer Continental Shelf Region
Environmental Sciences Management

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Principal Investigator: Dr. Frank G. Bercha, PEng

Bercha International Inc.
2926 Parkdale Boulevard NW
Calgary, Alberta, T2N 3S9, Canada
Email: berchaf@berchagroup.com

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ABSTRACT

Oil spill occurrence estimates were generated for the future hypothetical oil and gas development scenario, the Anchor A and Satellite A-2 (the Project), in the Chukchi Sea Outer Continental Shelf (OCS) Sale 193 Leased Area. Because sufficient historical data on offshore oil spills for this region do not exist, an oil spill occurrence model based on fault tree methodology was developed and applied. Using the fault trees, base data from the Gulf of Mexico and Pacific OCS including the variability of the data, were modified and augmented to represent expected Arctic offshore oil spillage frequencies. Three principal spill occurrence indicators, as follows, were quantified for each year of each scenario, as well as scenario life of field averages:

- Spill frequency per 1,000 years
- Spill frequency per 10^9 barrels produced
- Spill index, the product of spill size and spill frequency

These indicators were quantified for the following spill sizes:

- Small (S): 50 - 99 bbl
- Medium (M): 100 - 999 bbl
- Large (L): 1,000 - 9,999 bbl
- Huge (H): >= 10,000 bbl

Quantification was carried out for each future year for the Project scenario, with a range of development parameters, in duration up to 51 years. In addition, a comparative scenario for non-Arctic locations was formulated and analyzed for oil spill occurrence. Generally, it was found that the non-Arctic spill indicators were likely to be higher than those for similar scenarios in the Arctic. The computations were carried out using a Monte Carlo process to permit the inclusion of uncertainties in the base and scenario data and Arctic effects. A wide range of details for each scenario was generated, including the following:

- Expected time history of spill occurrences over the scenario life.
- Spill occurrence variations by spill volumes in the above spill size ranges.
- Spill occurrence variation by spill cause such as work boat anchoring or ice gouging.
- Spill occurrence contribution from each main facility type, including pipelines, platforms, and wells.
- Comparison of spill occurrence predictions between Arctic and non-Arctic scenarios.
- Life of field averages of spill occurrence estimators.
- The variability in the results due to uncertainties in the inputs was expressed as cumulative distribution functions and statistical measures.

In this final report, a detailed description of the methodology, results, and conclusions and recommendations is given, as well as a section on constraints of the study.

ACKNOWLEDGEMENTS

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- Caryn Smith, Contracting Officer's Representative
- Heather Crowley, Advisor
- Joanne M. Murphy, Contracting Officer

This work was carried out by Bercha International Inc (Bercha). Key Bercha personnel on the project team were as follows:

- Dr. Frank G. Bercha, Project Manager and Principal Engineer
- Milan Cerovšek, Reliability Engineering Specialist
- Wesley Abel, Offshore Engineering Specialist
- Susan Bercha, Editorial and Word Processing Manager

EXECUTIVE SUMMARY

A. Introduction

The United States Department of the Interior, Bureau of Ocean Energy Management (BOEM) Alaska Outer Continental Shelf (OCS) Region uses oil spill occurrence estimates for National Environmental Policy Act assessments for all parts of their area of assessment, ranging from near shore through shallow water, to deeper water. Although land to 3 nautical miles is not within BOEM jurisdiction, it is included in the BOEM environmental impact analysis; hence it is also included in the study area here.

B. Summary of Work Done

Oil spill occurrence estimates were generated for the future hypothetical oil and gas development scenario, the Anchor A and Satellite A-2 (the Project), in the Chukchi Sea Outer Continental Shelf (OCS) Sale 193 Leased Area. Because sufficient historical data on offshore oil spills for this region do not exist, an oil spill occurrence model based on fault tree methodology was developed and applied. Using the fault trees, base data from the Gulf of Mexico and Pacific OCS including the variability of the data, were modified and augmented to represent expected Arctic offshore oil spillage frequencies. Three principal spill occurrence indicators, as follows, were quantified for each year of each scenario, as well as scenario life of field averages:

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Quantification was carried out for each future year for the Project scenario, with a range of development parameters, in duration up to 51 years. In addition, a comparative scenario for non-Arctic locations was formulated and analyzed for oil spill occurrence. Generally, it was found that the non-Arctic spill indicators were likely to be higher than those for similar scenarios in the Arctic. The computations were carried out using a Monte Carlo process to permit the inclusion of uncertainties in the base and scenario data and Arctic effects. A wide range of details for each scenario was generated, including the following:

- Expected time history of spill occurrences over the scenario life.
- Spill occurrence variations by spill volumes in the above spill size ranges.
- Spill occurrence variation by spill cause such as work boat anchoring or ice gouging.

- Spill occurrence contribution from each main facility type, including pipelines, platforms, and wells.
- Comparison of spill occurrence predictions between Arctic and non-Arctic scenarios.
- Life of field averages of spill occurrence estimators.
- The variability in the results due to uncertainties in the inputs was expressed as cumulative distribution functions and statistical measures.

In this final report, a detailed description of the methodology, results, and conclusions and recommendations is given, as well as a section on constraints of the study.

C. Conclusions

C.1 General Conclusions

Oil spill occurrence indicators were quantified for a hypothetical future middle shelf offshore development scenario (the Project) in the Chukchi Sea Sale 193 Leased Area. The quantification included the consideration of the variability of historical and future scenario data, as well as that of Arctic effects in predicting oil spill occurrence indicators. Consideration of the variability of all input data yields both higher variability and a higher expected value of the spill occurrence indicators. The three types of spill occurrence indicators were: annual oil spill frequency, annual oil spill frequency per billion barrels produced, and annual spill index – and, additionally, the life of field averages for each of these three oil spill indicators were assessed.

C.2 Oil Spill Occurrence Indicators by Spill Size and Source

How do spill indicators for the Project scenario and for its non-Arctic counterpart vary by spill size and location? Table C.1 summarizes the Life of Field average spill indicator values by spill size and source. The following can be observed from Table C.1.

- Spill frequency per 10^3 years and per 10^9 barrels produced decreases considerably with increasing spill size for Arctic and non-Arctic scenarios.
- The spill index increases considerably with spill size for Arctic and non-Arctic scenarios.
- All non-Arctic Project spill indicators are greater than their Arctic counterparts.

How do the spill indicators vary by facility type for representative scenarios? The contributions of spill indicators by facility have been summarized by representative scenario years; again, Table C.1 gives the component contributions in absolute value and percent for each of the main facility types – namely, pipelines, platforms, and wells. The following may be noted from Table C.1:

- Platforms contribute the most (69%) to the two Arctic spill frequency indicators.
- Pipelines are next in relative contribution to spill frequencies (30%) and most in contribution to spill index (51%).
- Wells are the lowest contributors to spill frequencies (1%) and to spill index (16%).

It can be concluded that platforms are likely to have the most, but smaller spills, while wells will have the least number but larger spills. Pipelines will be in between, with more spills than wells.

Figures C.1 and C.2 show relative contributions by facility and spill size to the maximum spill index year 33 and Life of Field (LOF) average spill indicators, respectively. Although Life of Field average absolute values are considerably smaller than the maximum production year values, the proportional contributions by spill facility source and spill size are similar. In Figures C.1 and C.2, "TOTAL" designates the sum of the spill indicators for all spill sizes and facility types.

C.3 The Variance of Oil Spill Occurrence Indicators

A Monte Carlo analysis of the Project Life of Field average spill indicators was conducted to evaluate the effects of input uncertainties. Generally, the following was concluded:

- The variance of the frequency spill indicators decreases as spill size increases for pipelines and platforms. Substantial spills are less variable than all spills. Small and medium spills show the largest variability, while huge spills show the least variability for these facilities.
- The opposite occurs for wells, where large spills show greater variance than small ones, shown in the same manner.
- The variability of the spill index shows variance trends opposite to those of the frequency spill indicators for pipelines and platforms.

The Cumulative Distribution Functions presented in the report contain extensive information on the statistical properties of the spill indicators.

Table C.1
Summary of Life of Project Field Average Spill Indicators by Spill Source and Size

Spill Indicators LOF Average	CAA-SA2 Case			CAA-SA2 Case Non Arctic		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Small and Medium Spills 50-999 bbl	129.929	1.556	57	200.433	2.400	88
	83%	83%	21%	84%	84%	22%
Large Spills 1000-9999 bbl	18.395	0.220	98	26.429	0.317	140
	12%	12%	35%	11%	11%	35%
Huge Spills =>10000 bbl	8.160	0.098	122	11.040	0.132	173
	5%	5%	44%	5%	5%	43%
Substantial Spills =>1000 bbl	26.555	0.318	219	37.469	0.449	312
	17%	17%	79%	16%	16%	78%
All Spills	156.483	1.874	276	237.902	2.849	400
	100%	100%	100%	100%	100%	100%
Pipeline Spills	47.604	0.570	142	75.714	0.907	225
	30%	30%	51%	32%	32%	56%
Platform Spills	107.513	1.288	91	160.424	1.921	119
	69%	69%	33%	67%	67%	30%
Well Spills	1.366	0.016	43	1.764	0.021	56
	1%	1%	16%	1%	1%	14%
Platform and Well Spills	108.879	1.304	134	162.188	1.942	175
	70%	70%	49%	68%	68%	44%
All Spills	156.483	1.874	276	237.902	2.849	400
	100%	100%	100%	100%	100%	100%

BY SPILL SOURCE | **BY SPILL SIZE**

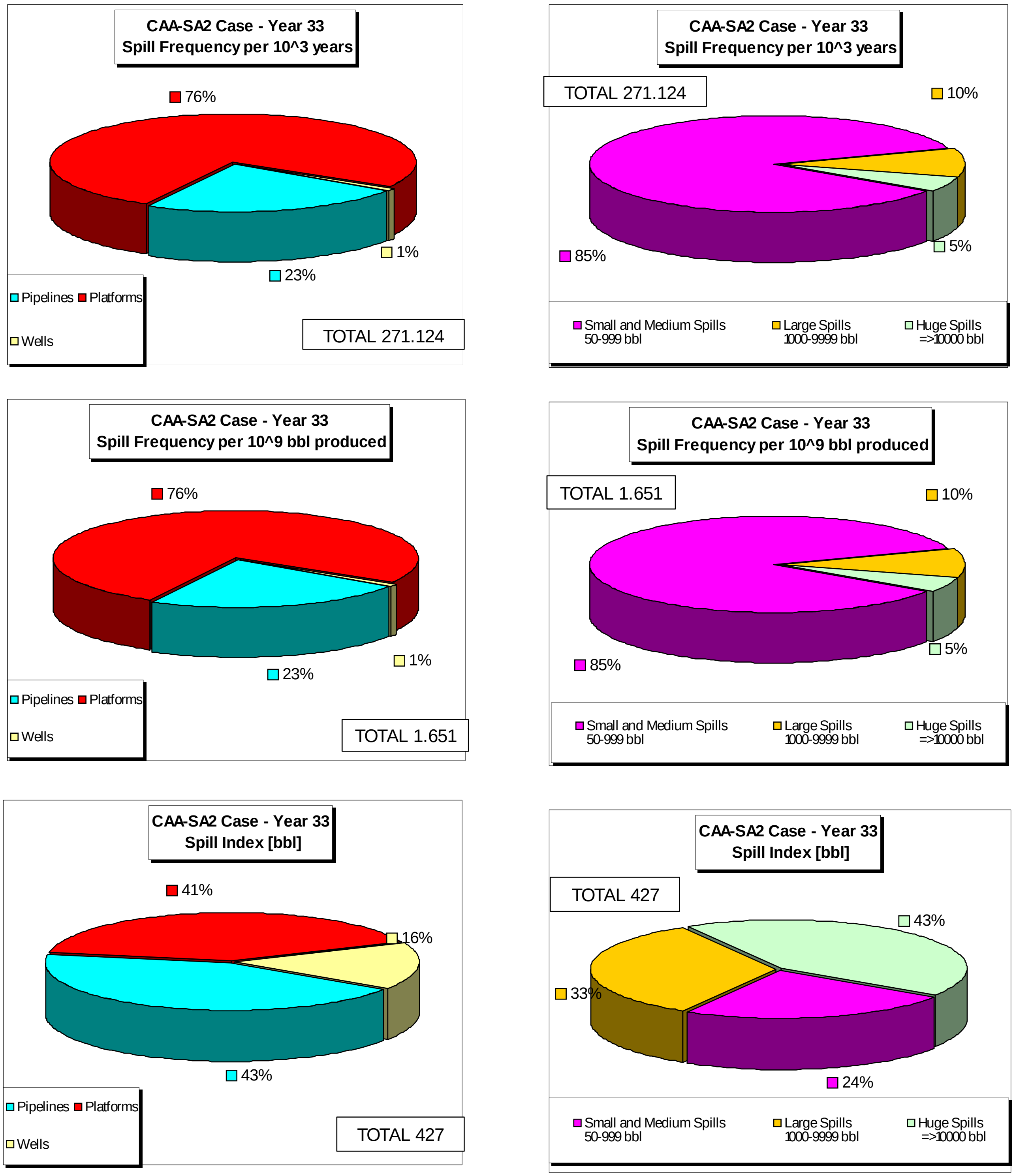

Figure C.1
Project – Year 33 – Spill Indicator Composition by Source and Spill Size

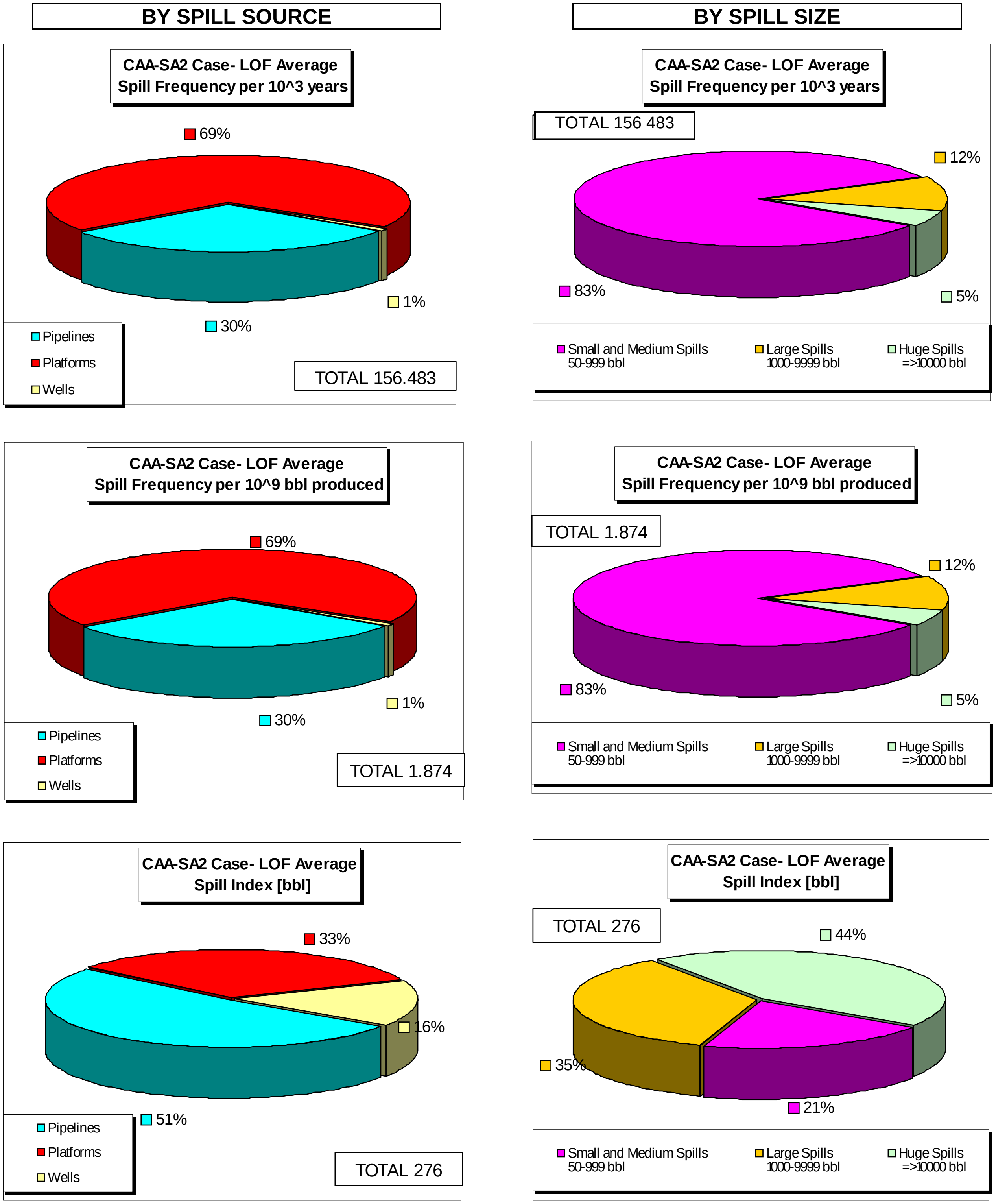

Figure C.2
Project – Life of Field Average Spill Indicator Composition by Source and Spill Size

D. The Methodology and its Applicability

An analytical tool for the prediction of oil spill occurrence indicators for systems without history, such as future offshore oil production developments in the Chukchi Sea OCS, has been developed based on the utilization of fault tree methodology. A wealth of information that can be utilized for the optimal planning and regulation of future developments is generated by the analytical tool. Key aspects of the analytical tool capability may be summarized as follows:

- Ability to generate expected and mean values as well as their variability in rigorous numerical statistical format.
- Use of verifiable input data based on Bureau of Safety and Environmental Enforcement (BSEE) or other historical spill data and statistics.
- Ability to independently vary the impacts of different causes on the spill occurrences as well as additional new causes that may be expected for the Arctic or other new environments.
- Ability to generate spill occurrence indicator characteristics such as annual variations, facility contributions, spill size distributions, and Life of Field (LOF) averages.
- Ability to generate comparative spill occurrence indicators such as those of comparable scenarios in more temperate regions.
- Capability to quantify uncertainties rigorously, together with their measures of variability.

E. Suggested Improvement to the Methodology and Results

During the work, a number of areas were identified where future improvements could be made, including: the input data, the scenarios, the application of the fault tree methodology, and finally the oil spill occurrence indicators themselves. These suggestions are summarized in the Final Report.

The Scenario was developed by the BOEM; it appears reasonable, and was incorporated in the form provided. For purposes of this analysis platform/well abandonment was only considered at the end of the Anchor and Satellite life leading to conservative estimates of spill frequency. The only consideration appears to be that the facility abandonment rate is considerably lower than the rate of decline in production, resulting in very high estimates of spill frequency per 10^9 barrels produced during the pre-abandonment years

The following comments can be made on constraints associated with the indicators that have been generated:

- The indicators are a function of the input and scenario data noted above. For example, yearly abandonment rates for platforms rather than by end of Anchor and Satellite life would lower the spill frequency per 10^9 barrels produced during the pre-abandonment years.

- The model generating the indicators is fundamentally a linear model which ignores the effects of scale, of time variations such as the learning and wear-out curves (Bathtub curve), climate change, and production volume non-linear effects.

F. Recommendations

The following recommendations based on the work may be made:

- Continue to utilize the Monte Carlo spill occurrence indicator model for new scenarios to support BOEM needs, as it is currently the best predictive spill occurrence model available.
- Utilize the oil spill occurrence indicator model to generate additional model validation information, including direct application to existing non-Arctic scenarios, such as GOM and PAC projects, which have an offshore oil spill statistical history.
- Utilize the oil spill occurrence indicator model in a sensitivity mode to identify the importance of different Arctic effect variables introduced to provide a prioritized list of those items having the highest potential impact on Arctic oil spills.
- Generalize the model so that it can be run both in an adjusted expected value and a distributed value (Monte Carlo) form with the intent that expected value form can be utilized without the Monte Carlo add-in for preliminary estimates and sensitivity analyses, while for more comprehensive rigorous studies, the Monte Carlo version can be used.

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GLOSSARY OF TERMS AND ACRONYMS

Bbbl	Billion Barrels
BOEM	**B**ureau of **O**cean **E**nergy **M**anagement, Department of the Interior
BSEE	**B**ureau of **S**afety and **E**nvironmental **E**nforcement, Department of the Interior
CDF	**C**umulative **D**istribution **F**unction
Consequence	The direct effect of an accidental event.
GOM	**G**ulf **o**f **M**exico OCS
Hazard	A condition with a potential to create risks such as accidental leakage of natural gas from a pressurized vessel.
KBpd	Thousand Barrels per day
LOF	**L**ife **o**f **F**ield
MMbbl	Million Barrels
LOWC	**L**oss **o**f **W**ell **C**ontrol
MMS	**M**inerals **M**anagement **S**ervice. On October 1, 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the Minerals Management Service (MMS), was replaced by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) as part of a major reorganization
Monte Carlo	A numerical method for evaluating algebraic combinations of statistical distributions.
OCS	**O**uter **C**ontinental **S**helf
PAC	Pacific OCS
QRA	**Q**uantitative **R**isk **A**ssessment
Risk	A compound measure of the probability and magnitude of adverse effect.
RLS	Release
SINTEF	The Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology
Spill Frequency	The number of spills of a given spill size range per year. Usually expressed as spills per 1,000 years (and so indicated).
Spill Frequency per Barrel Produced	The number of spills of a given spill size range per barrel produced. Usually expressed as spills per billion barrels produced (and so indicated).
Spill Index	The product of spill frequency for a given spill size range and the mean spill size for that spill size range.
Spill Occurrence	Characterization of an oil spill as an annual frequency and associated spill size or spill size range.

Spill Occurrence Indicator	Any of the oil spill occurrence characteristics; namely, spill frequency, spill frequency per barrel produced, or spill index (defined above).
Spill Sizes	Small (S): 50 - 99 bbl Medium (M): 100 - 999 bbl Large (L): 1,000 - 9,999 bbl Huge (H): >=10,000 bbl

CHAPTER 1

INTRODUCTION

1.1 General Introduction

The United States Department of the Interior, Bureau of Ocean Energy Management (BOEM) Alaska Outer Continental Shelf (OCS) Region uses oil spill occurrence estimates for National Environmental Policy Act assessments for all parts of their area of assessment, ranging from nearshore through shallow water, to deeper water. Although land to 3 nautical miles is not within BOEM jurisdiction, it is included in the BOEM environmental impact analysis; hence it is also included in the study area here. In 2002, 2006, and 2008 studies were carried out by Bercha International Inc. [16, 17, 18, 19] [*] to assess and quantify oil spill occurrence indicators for the Chukchi and Beaufort seas. In this study, methodologies based on fault tree analysis developed for the assessment of oil spill rates associated with exploration and production facilities and operations in OCS Arctic waters [18] are applied to a specific Scenario; namely the Sale 193 Leased Area, termed the Anchor-A and Satellite A-2 development, hereinafter called the Project.

The prediction of the reliability (or failure) of systems without history can be approached through a variety of mathematical techniques, with one of the most preferable and accepted being fault trees [1, 6, 10, 23, 28, 32, 61], and their combination with numerical distribution methods such as Monte Carlo simulation [6, 16]. In the previous studies [16, 17], fault tree methodology was applied to the prediction of oil spill rates for oil and gas developments in the Chukchi Sea.

As there are limited offshore Arctic oil spill occurrences, associated data worldwide and from the Gulf of Mexico (GOM) and Pacific (PAC) OCS data [14, 15] were used as a starting point to develop a simulation model of oil spill occurrence probabilities. The model for non-Arctic occurrence probabilities was then modified to include Arctic effects and their variabilities. In the early studies [19], variability in the non-Arctic input data was considered; but variability of the future development scenario physical facility parameters, such as miles of subsea pipeline, was not considered. In the present study, as well as in the preceding Chukchi Sea studies [16,17], both the historical data variability and that of the future development scenario characteristics is included in calculation of oil spill occurrence probabilities.

The present document deals with the evaluation of oil spill potential associated with a possible development resulting from the Sale 193 Leased Area in the Chukchi Sea generally located as shown in Figure 1.1. The development is called "Anchor A and Satellite A-2", and is referred to in this document as "the Project".

[*] Numbers in square brackets refer to citations listed in the "References" section of this report.

Figure 1.1
Study Area Map

1.2 Study Objectives

The objectives of this study are as follows:

- Assimilate North Sea and U.S. OCS oil spill statistics [14, 15], and evaluate their applicability to leased tracts which were offered in the Chukchi Sea Sale 193.
- Develop the fault trees for estimating oil spill occurrences from hypothetical Chukchi Sea OCS developments associated with spills of different size categories.
- Using the fault tree approach, develop alternative oil spill indicators and assess their variability, including effect of variability of both the historical data and the future development scenario parameters.
- Evaluate the variability of the non-Arctic factors, and include this in the Monte Carlo analysis.

1.3 Study Area Definition

The geographical study area is the Outer Continental Shelf in the U.S. Chukchi Sea, as generally illustrated in Figure 1.1. Of interest is the offshore area from landfall to approximately the 60-meter isobath. This area is selected due to the possibility of future oil and gas development within it, based on Sale 193 leases shown in Figure 1.2.

The total development under the Sale 193 Leased Area is Termed “Anchor A and Satellite A-2” hereafter called the Project. In the current study it is assumed that both Anchor A and Satellite A-2 prospects become developed, and accordingly, are analytically treated as one single entity. The general schedule includes the following principal milestones:

- Year 1 – Start
- Year 3 – Start of exploration well drilling and hence spill potential.
- Year 10 – Start of:
    - Development well drilling
    - Pipeline construction completion
    - First oil production
- Year 31 – Start of dry gas production
- Year 53 – End of oil production (51 years of spill potential)
- Year 75 – Abandonment and decommissioning

A detailed description of the Project, provided by BOEM, is given in Appendix A. Selected project data presented in Appendix A are restricted to those data supporting the analysis. In reality some limited initial exploration has taken place and more may begin in calendar year 2015 and beyond.

1.4 General Background

The final reports [16, 17, 18, 19] described the methodology and results of the fault tree method for the evaluation of oil spill occurrence estimators for the Beaufort and Chukchi seas. The focus of the first report [19] was on the initial development of a fault tree method to model both non-Arctic GOM spill causes as well as Arctic causes and effects that would be encountered in the Beaufort and Chukchi Seas OCS Regions. The variability of the parameters associated with Arctic effects was developed in order to provide an estimate of the variance in the spill occurrence predictions resulting directly from variances in the Arctic effects. In addition, in 2006 [17, 18] and 2008 [16], variance in the Gulf of Mexico (GOM) historical data was incorporated. In the most recent reports [16], the variability of the future development scenario parameters is also considered. In the present study, all variances are considered in a manner analogous to that of the March 2008 [16] study. These variances were numerically incorporated through the use of Monte Carlo simulation for the fault tree model numerical predictions.

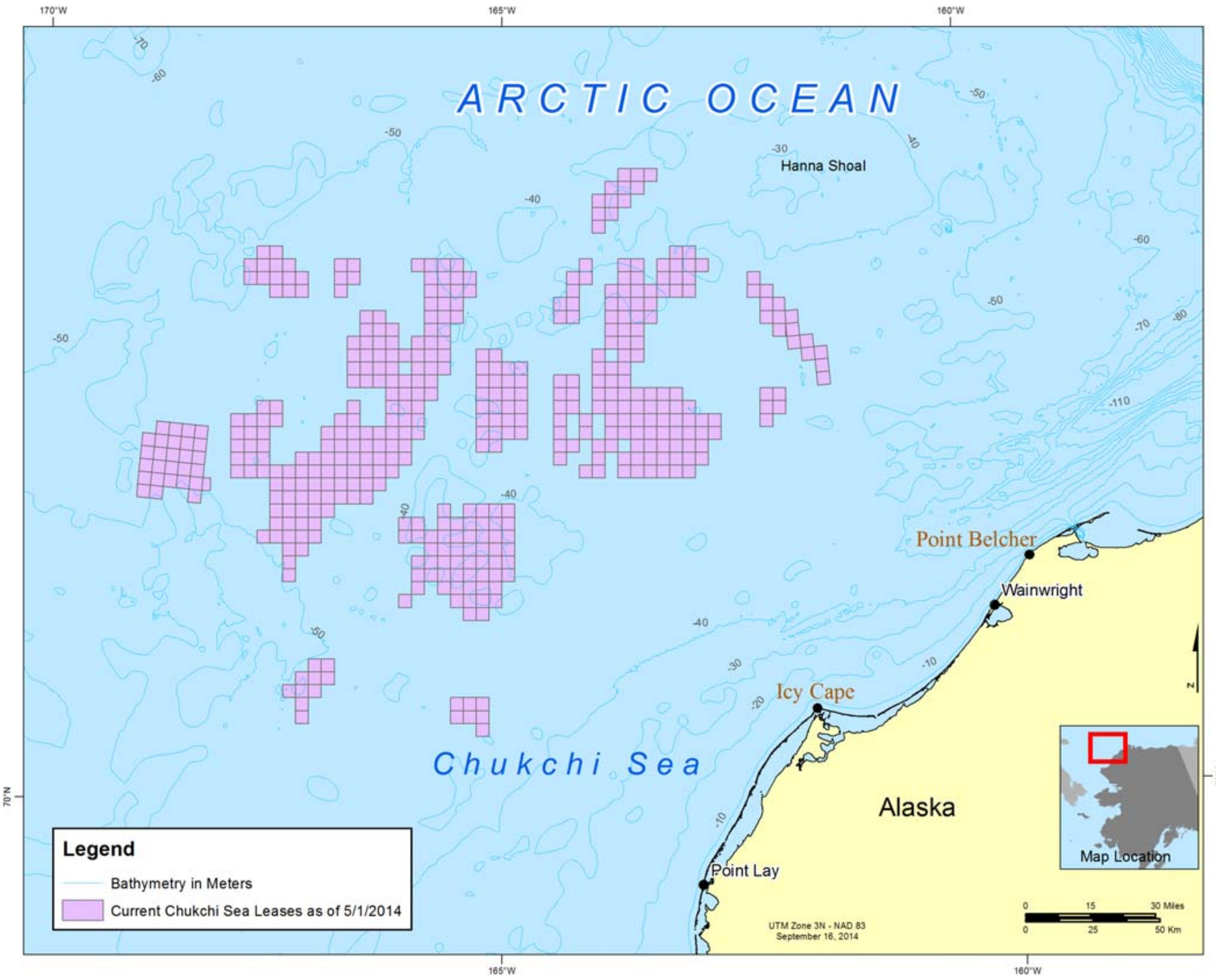


Figure 1.2
Sale 193 Leased Area

1.5 Technical Approaches

Uncertainties in the results of oil spill occurrence predictions generated in this study can be attributed to uncertainties in input data, scenario characterization, and the occurrence model. In the original 2002 study [19], uncertainties in input data were quantified for the Arctic effects only. Uncertainties in the scenario were included through the choice of scenarios representing the expected and maximum development levels. In the 2008 study [16], uncertainties in the non-Arctic input data were also included. Thus the principal source of uncertainty in the occurrence results was that caused by uncertainties in the Arctic and non-Arctic input parameters themselves.

The non-Arctic input parameters fall under two principal categories as follows:

- Spill frequencies
- Spill volumes

These spill frequencies and volumes as used in the study were derived from the following principal sources:

- Pipeline spills – GOM and PAC OCS data
- Platform spills – GOM and PAC OCS data
- Well (drilling and production) Loss of Well Control (LOWC) spills – GOM and North Sea data

The specific sources of the data are described in detail in Chapter 2 of this report.

In the March 2008 [16] and the current study, uncertainties in the above data were considered. However, the following main facility parameters were used as expected values:

- Number of wells drilled
- Number of platforms
- Number of platform and subsea production wells
- Subsea pipeline length for all 3 water depths:
    - For pipelines less than or equal to 10” nominal diameter
    - For pipelines greater than 10” nominal diameter.

The inclusion of variability of the input data is intended to provide a realistic estimate of the spill occurrence indicators and their resultant variability.

1.6 Scope of Work

<u>Task 1:</u> ***Data Assimilation***

a) Update of GOM and PAC pipeline and platform spill statistics [4, 15].

b) Loss of Well Control (LOWC) statistics [4, 14].

c) Assimilation and update of Project information (Appendix A).

Task 2: ***Development of Arctic Spill Frequency Causal Event and Total Probability Distributions***

a) Development of Arctic spill frequency causal event probability distributions associated with pipeline spills.

b) Development of Arctic spill frequency causal event probability distributions associated with platform spills.

c) Development of Arctic spill frequency causal event probability distributions associated with well drilling and production well LOWC's.

Task 3: ***Development of Non-Arctic Total Annual Spill Frequency and Volume Probability Distributions***

a) Development of non-Arctic total annual spill frequency and volume distribution for pipelines.

b) Development of non-Arctic total annual spill frequency and volume distribution for platforms.

c) Development of non-Arctic total annual spill frequency and volume distribution for well drilling and production wells.

Task 4: ***Generation of Oil Spill Occurrence Estimator Probability Distributions***

a) Variability in future development scenario parameters.

b) Model runs for variable Chukchi Sea Project scenarios.

c) Model runs for comparative non-Arctic scenario.

Task 5: ***Reporting***

a) Preliminary results following completion of Tasks 1, 2, 3, and 4.

b) Draft Final Report and Final Report.

1.7 Work Organization

The present study consisted of statistical and engineering investigations, followed by numerical simulation. Although the assimilation of historical and future scenario data is of key importance to the work, the salient contribution consisted primarily of the analytical work involving fault trees and oil spill occurrence indicator generation. Although the individual calculations are relatively simple, the subdivision of the calculations into realistic representative categories of facilities, spill sizes, and water depth for different variables in the scenario resulted in a relatively complex mix of computations, generally illustrated in the flow chart in Figure 1.3.

The flow chart in Figure 1.3, of course, does not show all the different combinations and permutations; rather, it indicates the typical calculations for one case, and suggests the balance by dotted lines. Moving from left to right; initially historical data were obtained for each of three principal facility categories, pipelines, platforms, and wells. Pipelines were further subdivided among <= 10 inch and >10 inch diameter lines. Wells were categorized in two ways: according to producing wells and the drilling of exploration and development wells. For each of the above facility subcategories, spill causes were analyzed for small, medium, large, huge, and substantial spills, defined as follows:

- Small (S): 50 to 99 bbl
- Medium (M): 100 to 999 bbl
- Large (L): 1,000 to 9,999 bbl
- Huge (H): >= 10,000 bbl
- Substantial (SB): >= 1,000 bbl

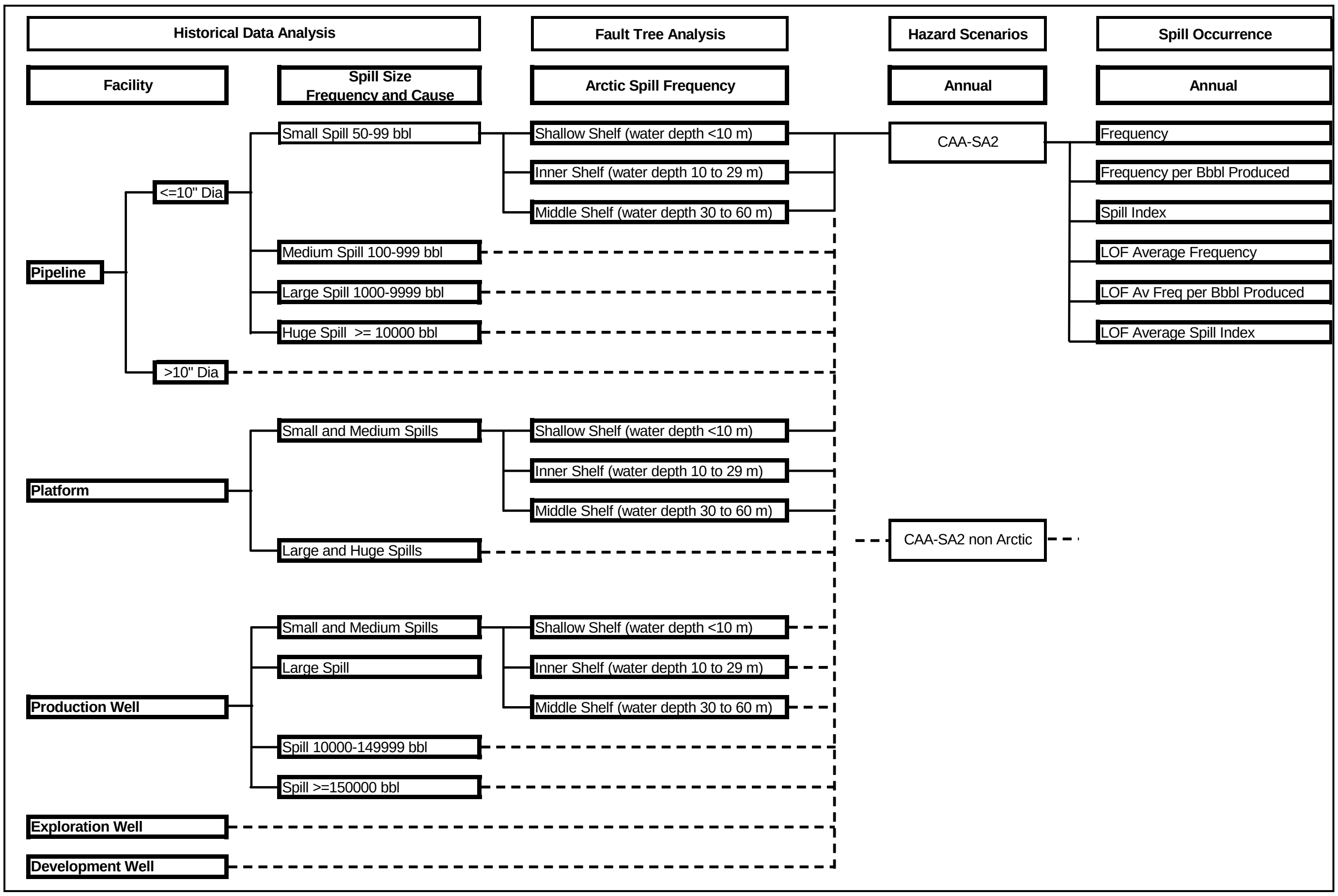


Figure 1.3
Calculation Flow Chart

Substantial spills, which are spills of 1,000 bbl or more (Large and Huge), are also identified. Fractional spill sizes were rounded up or down to the nearest whole number, with rounding up for any decimal ending in 5. For example, a spill of 99.5 bbl is taken as 100 bbl; 99.42 is taken as 99 bbl.

For well Loss of Well Control (LOWC) releases, one additional category of spill volumes is added: spills >= 150,000 bbl [4, 14].

In the interests of conciseness and clarity, the above main categories of spill sizes will generally be designated by either their name (small, medium, large, huge, substantial) or, when space is limited, by their acronym (S, M, L, H, and SB), in the balance of this report.

Next, in the frequency analysis utilizing fault trees, each of three representative Arctic water depth ranges as applicable, are used. The Arctic water depth ranges are correlated to those used in previous Arctic OCS analyses [16, 17], but using somewhat different terminology. The following water depth ranges are used here, giving both terminology used here (in bold) and that of earlier studies:

- **Shallow Shelf** Shallow - < 10 meters
- **Inner Shelf** Medium - 10 to 29 meters
- **Middle Shelf** Deep - 30 to 60 meters

One principal future development scenario was defined for the Chukchi Sea, as well as a comparable non-Arctic (hypothetical) scenario. The Arctic scenario is represented as Anchor A and Satellite A-2 production volume case, called the Project herein. The hypothetical non-Arctic scenario was developed for comparative purposes on the assumption that it was located with the same facility and water depth distribution in a non-Arctic area such as the GOM OCS. This permitted the comparison of the spill indicator results with and without the application of the fault tree analysis to account for Arctic effects.

Finally, for each of the scenarios considered, four principal oil spill occurrence indicators were generated, as follows:

- Oil spill frequency
- Oil spill frequency per billion barrels produced
- Spill index, which is the product of the oil spill frequency and the mean spill size (for the particular category under consideration)
- Life of Field Average Indicators

1.8 Outline of Report

Following this brief introductory chapter, Chapter 2 summarizes the historical data assimilation and analysis detailed in [14, 15], Chapter 3 defines the future Project development scenario used, Chapter 4 discusses the fault tree analysis to obtain Arctic oil spill frequencies, while Chapter 5 summarizes the results of the oil spill occurrence indicator computations and their statistical distributions. Chapter 6 summarizes conclusions and recommendations including a section on the benefits of and future recommendations derived from the present study. Extensive references and bibliography are given in the References. Appendix A gives a detailed description of the Project.

CHAPTER 2

HISTORICAL DATA AND STATISTICS

2.1 Approaches to Historical Data

Historical data on offshore oil spills from pipelines, platforms, and Loss of Well Control (LOWC) were utilized as a numerical starting point for predicting Arctic offshore oil spill characteristics. Because statistics on Arctic offshore oil spills do not exist, oil spill statistics for temperate offshore locations were utilized, and subsequently analytically adjusted to represent the Project Arctic conditions. Although Arctic offshore exploration and production was started in the early 1970s, operations have been sporadic, with very few spills, so that a statistical history cannot be generated [12, 27].

The following data sets or databases were utilized:

(a) GOM and PAC OCS Pipeline Spills (1972-2010)
(b) GOM and PAC OCS Platform Spills (1972-2010)
(c) LOWC, GOM and North Sea Data (1980-2011)

The GOM and PAC pipeline and platform statistics categories of data are discussed in detail in the GOM and PAC update report [15], while the LOWC data are based on the results of an ongoing BOEM analysis [14], summarized in the recently published paper [4]. The contents of the balance of this chapter are restricted to the presentation of only those data sets utilized in the present study.

2.2 Pipeline Spills

The pipeline spill statistics generated in this update are basic spill statistics. First, the number of spills by size occurring for each causal category is given. Next, spill causes by two principal spill size categories are given, and transformed to spill frequencies per kilometer-year by dividing the number of kilometer-years exposure. And finally, the spill frequency distribution for spills of different size categories, by pipe diameter is determined. Table 2.1 summarizes the spill occurrences by size for each of the principal causes reported in the Bureau of Safety and Environmental Enforcement (BSEE) database. Both the exact spill size in barrels and the spill size distribution by each of the spill size categories are given in Table 2.1.

Table 2.2 gives the pipeline hydrocarbon spill statistics by cause. These statistics are given as the probability of occurrence per kilometer-year of operating pipeline. Thus, for example, approximately 13.44 spills per 100,000 km-yrs in the small and medium size category are projected. Of these, it is expected that approximately 0.90 per 100,000 km-yrs can be attributed to pipe corrosion.

Table 2.1
Analysis of GOM and PAC OCS Pipeline Spill Data for Causal Distribution and Spill Size (1972-2010)

CAUSE CLASSIFICATION	NUMBER OF SPILLS 1972-2010	SPILL SIZE (bbl)													NUMBER OF SPILLS					
		1	2	3	4	5	6	7	8	9	10	11	12	13	S	M	L	H	SM	LH
CORROSION	4														1	2	1		3	1
External	1	80													1				1	
Internal	3	100	5000	414												2	1		2	1
THIRD PARTY IMPACT	20														2	7	8	3	9	11
Anchor Impact	13	19833	65	50	300	900	323	15576	2000	800	1211	2240	870	1500	2	5	4	2	7	6
Jackup Rig or Spud Barge	2	200	3200													1	1		1	1
Trawl/Fishing Net	5	4000	100	14423	4569	4533										1	3	1	1	4
OPERATION IMPACT	4														3		1		3	1
Rig Anchoring	1	50													1				1	
Work Boat Anchoring	3	50	5100	50											2		1		2	1
MECHANICAL	3															3			3	
Connection Failure	2	135	150													2			2	
Material Failure	1	210														1			1	
NATURAL HAZARD	28														9	15	4		24	4
Mud Slide	3	250	80	8212											1	1	1		2	1
Storm/ Hurricane	25	3500	1720	671	126	200	250	260	95	123	960	50	55	132	8	14	3		22	3
		50	75	100	862	67	108	69	108	56	1316	209	268							
UNKNOWN	3	119	190	188												3			3	
TOTALS	62														15	30	14	3	45	17

Table 2.2
Distribution and Frequency of Historical Pipeline Spills (1972-2010)

CAUSE CLASSIFICATION 1972-2010	Small and Medium Spills 50-999 bbl				Large and Huge Spills >=1000 bbl			
	HISTORICAL DISTRIBUTION %	NUMBER OF SPILLS	EXPOSURE (km-years)	FREQUENCY spill per 10^5 km-year	HISTORICAL DISTRIBUTION %	NUMBER OF SPILLS	EXPOSURE (km-years)	FREQUENCY spill per 10^5 km-year
CORROSION	6.67	3	334,764	0.896	5.88	1	334,764	0.299
External	2.22	1		0.299				
Internal	4.44	2		0.597	5.88	1		0.299
THIRD PARTY IMPACT	20.00	9		2.688	64.71	11		3.286
Anchor Impact	15.56	7		2.091	35.29	6		1.792
Jackup Rig or Spud Barge	2.22	1		0.299	5.88	1		0.299
Trawl/Fishing Net	2.22	1		0.030	23.53	4		1.195
OPERATION IMPACT	6.67	3		0.896	5.88	1		0.299
Rig Anchoring	2.22	1		0.299				
Work Boat Anchoring	4.44	2		0.597	5.88	1		0.299
MECHANICAL	6.67	3		0.896				
Connection Failure	4.44	2		0.597				
Material Failure	2.22	1		0.299				
NATURAL HAZARD	53.33	24		7.169	23.53	4		1.195
Mud Slide	4.44	2		0.597	5.88	1		0.299
Storm/ Hurricane	48.89	22		6.572	17.65	3		0.896
UNKNOWN	6.67	3		0.896				
TOTALS	100.00	45		13.442	100.00	17		5.078

Finally, Table 2.3 summarizes the pipeline hydrocarbon spill statistics by spill size and pipe diameter; while Table 2.4 gives the derived values for the present study. For example, if there were 30 data points, the upper 90% (or high value) was the third highest, while the lower 90% (or low value) was selected as the third lowest, which was invariably zero, as numerous years had no spills. Next, the third highest value was divided by the historical value to get the high factor. Finally, the high factor was used to obtain the high value by multiplying the applicable historical frequency by this high factor. The expected value is calculated as described in Chapter 4 (Equation 4.4) while the mode is calculated from the triangular distribution relationship [31], as follows:

$$\textit{Mode} = 3 \times \textit{Historical} - \textit{High} - \textit{Low} \qquad \textbf{(2.1)}$$

Table 2.3
GOM and PAC OCS Pipeline Spills Statistics Summary (1972-2010)

GOM and PAC OCS Pipeline Spills, Categorized 1972-2010			Spill Statistics (Number of Spills)	Exposure (km-years)	Frequency (spills per 10^5 km-years)
By Pipe Diameter		< = 10"	38	222,716	17.062
		> 10"	24	112,047	21.420
By Spill Size		Small <100 bbl	15	334,764	4.481
		Medium 100 - 999 bbl	30	334,764	8.962
		Large 1000 - 9999 bbl	14	334,764	4.182
		Huge >=10000 bbl	3	334,764	0.896
By Diameter, By Spill Size	<=10"	Small <100 bbl	11	222,716	4.939
		Medium 100 - 999 bbl	19	222,716	8.531
		Large 1000 - 9999 bbl	7	222,716	3.143
		Huge >=10000 bbl	1	222,716	0.449
	> 10"	Small <100 bbl	4	112,047	3.570
		Medium 100 - 999 bbl	11	112,047	9.817
		Large 1000 - 9999 bbl	7	112,047	6.247
		Huge >=10000 bbl	2	112,047	1.785

Table 2.4
Pipeline Historical Spill Frequency Variability

GOM and PAC OCS Pipeline Spills, Categorized 1972-2010 *By Diameter, By Spill Size*		Low Factor	High Factor	Frequency spill per 10^5 km-years				
				Historical	Low	Mode	High	Expected
<=10"	Small	0	2.81	4.9390	0	0.9384	13.8786	6.1956
	Medium	0	2.81	8.5310	0	1.6209	23.9722	10.7014
	Large	0	2.81	3.1430	0	0.5972	8.8319	3.9426
	Huge	0	2.81	0.4490	0	0.0853	1.2617	0.5632
>10"	Small	0	2.81	3.5699	0	0.6783	10.0315	4.4782
	Medium	0	2.81	9.8173	0	1.8653	27.5866	12.3149
	Large	0	2.81	6.2474	0	1.1870	17.5551	7.8368
	Huge	0	2.81	1.7850	0	0.3391	5.0158	2.2319

2.3 Platform Spills

The primary platform spill statistical information required is the spill frequency distribution by different causes and spill sizes, and the spill rate per well year. Table 2.5 summarizes the spill size distribution among the principal reported causes. As can be seen, the major cause attributable to over 50% of the spills is that of Hurricanes. Also, hurricanes caused many of the larger spill volumes, giving the largest spill volume total. The largest single spill, however, is the tank failure which caused a spill of nearly 10,000 barrels [15]. From a review of the platform spill data [15], it can be seen that platform spills as defined here, are limited to those caused from process, storage, or transfer equipment losses of containment, so that they do not include LOWC's, which are dealt with subsequently here in Section 2.4.

Table 2.5
Analysis of GOM and PAC OCS Platform Spill Data for Causal Distribution and Spill Size (1972-2010)

CAUSE CLASSIFICATION	NUMBER OF SPILLS 1972-2010	SPILL SIZE (bbl)															NUMBER OF SPILLS					
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	S	M	L	H	SM	LH
EQUIPMENT FAILURE	36	9,935	130	50	300	77	104	321	60	95	83	118	210	50	228	600	19	16	1		35	1
		77	320	200	77	107	50	643	50	58	52	50	55	400	55	280						
		50	75	435	62	127	50															
HUMAN ERROR	13	95	120	286	58	400	100	60	64	100	600	170	60	264			5	8			13	
COLLISION	1	119																1			1	
WEATHER	7	7,000	239	100	1,500	80	214	100									1	4	2		5	2
HURRICANE	67	1,456	66	497	741	52	55	264	106	66	510	141	242	204	195	325	27	36	4		63	4
		380	130	110	195	307	71	159	94	51	101	51	50	51	97	614						
		1,572	77	2,000	181	188	101	1,494	67	659	166	53	51	63	528	59						
		133	51	54	685	103	62	205	52	513	200	550	140	50	127	70						
		194	170	196	72	58	54	62														
TOTALS	124																52	65	7		117	7

The spill rate data, given here using an exposure variable of production well-years [15], is shown in Table 2.6, again, by causal distribution as well as for two broad spill size categories of small and medium spills and large and huge spills. Here, it becomes immediately evident that the largest spill potential in terms of volume is attributable to hurricanes, which are responsible for roughly 57% of the large and huge spills. Finally, Table 2.7 gives the fault tree analysis statistical input data derived from Table 2.6. It should be noted that for platforms, only the two spill size categories given in Table 2.7 have been assessed [15].

Table 2.6
Causal and Spill Size Distribution of GOM and PAC OCS Platform Spills (1972-2010)

	Small and Medium Spills 50-999 bbl				Large and Huge Spills >=1000 bbl			
CAUSE CLASSIFICATION 1972 - 2010 (no LOWC)	HISTORICAL DISTRIBUTION %	NUMBER OF SPILLS	EXPOSURE [well-years]	FREQUENCY spill per 10^4well-year	HISTORICAL DISTRIBUTION %	NUMBER OF SPILLS	EXPOSURE [well-years]	FREQUENCY spill per 10^4well-year
EQUIPMENT FAILURE	29.91	35	245,486	1.426	14.29	1	245,486	0.041
HUMAN ERROR	11.11	13		0.530				
COLLISION	0.85	1		0.041				
WEATHER	4.27	5		0.204	28.57	2		0.081
HURRICANE	53.85	63		2.566	57.14	4		0.163
TOTALS	100.00	117		4.766	100.00	7		0.285

Table 2.7
Platform Historical Spill Frequency Variability (1972-2010)

Spill Size	Frequency Unit	Low Factor	High Factor	Historical	Low	Mode	High	Expected
Small and Medium Spills (50-999 bbl)	Spill per 10^4 well-year	0	3	4.766	0.000	0.000	14.298	6.355
Large and Huge Spills (>= 1000 bbl)	Spill per 10^4 well-year	0	3	0.285	0.000	0.000	0.855	0.380

2.4 Loss of Well Control (LOWC) Data

The development scenarios considered under this study include both the drilling of exploratory and development wells, and the production wells producing oil. In earlier studies [18, 10], to identify a basis for the non-Arctic historical oil well blowout statistics, a number of sources were reviewed including the Northstar and Liberty oil development project reports [51], a study by Scandpower giving the cumulative distribution function for oil blowout releases [54, 55], as well as the book by Per Holand entitled “Offshore Blowouts” [31], which gives risk analysis data from the SINTEF worldwide offshore blowout database [30].

However, the current work for BOEM on LOWC statistics [4, 14] was used as the principal data source for the present work. Table 2.8 gives a summary of the historical data analysis for production wells and the drilling of exploratory and development wells based on GOM data. The combination of these statistics together with the cumulative distribution function for LOWC release volumes given in [4, 20], results in the LOWC spill volume frequency distribution as summarized in Table 2.8. Finally, combining the population parameters of oil LOWC’s from Table 2.8 with the size distribution factors [14], one arrives at the historical oil spill blowout distribution characteristics by spill size and well type, summarized in Table 2.9.

Table 2.8
Well LOWC Historical Spill Size Distribution (1980 - 2011)

EVENT	FREQUENCY UNIT	Small and Medium Spills 50-999 bbl	Large Spills 1000-9999 bbl	Small, Medium, and Large Spills 50-9999 bbl	Spills 10000-149999 bbl	Spills >=150000 bbl	All spills
		HISTORICAL FREQUENCY 1980-2011 BSEE Data					
PRODUCTION WELL	spills per 10^4 well-year	0.028	0.011	0.039	0.007	0.005	0.051
EXPLORATION WELL DRILLING	spills per 10^4 wells	1.330	0.539	1.869	0.350	0.217	2.436
DEVELOPMENT WELL DRILLING	spills per 10^4 wells	0.283	0.115	0.398	0.075	0.046	0.519

Table 2.9
Well LOWC Historical Spill Probability and Size Variability (1980 - 2011)

Spill Size	EVENT	FREQUENCY UNIT	Low Factor	High Factor	Frequencies				
					Historical	Low	Mode	High	Expected
Small and Medium Spills 50-999 bbl	PRODUCTION WELL	spill per 10^4 well-year	0.448	1.545	0.028	0.012	0.028	0.043	0.028
	EXPLORATION WELL DRILLING	spill per 10^4 wells	0.439	2.036	1.330	0.584	0.698	2.708	1.530
	DEVELOPMENT WELL DRILLING	spill per 10^4 wells	0.437	1.760	0.283	0.124	0.227	0.498	0.299
Large Spills 1000-9999 bbl	PRODUCTION WELL	spill per 10^4 well-year	0.448	1.545	0.011	0.005	0.011	0.017	0.011
	EXPLORATION WELL DRILLING	spill per 10^4 wells	0.439	2.036	0.539	0.237	0.283	1.097	0.620
	DEVELOPMENT WELL DRILLING	spill per 10^4 wells	0.437	1.760	0.115	0.050	0.092	0.202	0.122
Small, Medium and Large Spills 50-9999 bbl	PRODUCTION WELL	spill per 10^4 well-year	0.448	1.545	0.039	0.017	0.039	0.060	0.039
	EXPLORATION WELL DRILLING	spill per 10^4 wells	0.439	2.036	1.869	0.821	0.981	3.805	2.150
	DEVELOPMENT WELL DRILLING	spill per 10^4 wells	0.437	1.760	0.398	0.174	0.320	0.700	0.421
Spill 10000-149999 bbl	PRODUCTION WELL	spill per 10^4 well-year	0.448	1.545	0.007	0.003	0.007	0.011	0.007
	EXPLORATION WELL DRILLING	spill per 10^4 wells	0.439	2.036	0.350	0.154	0.184	0.713	0.403
	DEVELOPMENT WELL DRILLING	spill per 10^4 wells	0.437	1.760	0.075	0.033	0.060	0.131	0.079
Spill >=150000 bbl	PRODUCTION WELL	spill per 10^4 well-year	0.448	1.545	0.005	0.002	0.005	0.007	0.004
	EXPLORATION WELL DRILLING	spill per 10^4 wells	0.439	2.036	0.217	0.095	0.114	0.442	0.250
	DEVELOPMENT WELL DRILLING	spill per 10^4 wells	0.437	1.760	0.046	0.020	0.037	0.081	0.049

2.5 Arctic Effects Historical Data

2.5.1 General Approaches to the Quantification of Arctic Effects

There are essentially two main categories of Arctic effects; namely, those that are unique to the Arctic, such as marine ice effects, and those that are the same types of effects as those in temperate areas, but occurring with a different frequency, such as anchor impacts on subsea pipelines. The first will be termed “unique” effects; the second, “modified” effects. Modified Arctic effects are dealt with in conjunction with the fault tree analysis described in Chapter 4. Only those Arctic effects or hazards unique to the Arctic, and potentially having a historical occurrence database, such as ice gouging, are discussed in the balance of this section.

2.5.2 Ice Gouging

Ice gouging occurs when a moving ice feature contacts the sea bottom and penetrates into it, generally as it moves against a positive sea bottom slope. The ice feature can be a multiyear ridge, a hummock, or ice rafting formation. Various studies have been conducted on the frequency and depth distribution of ice gouges [2, 11, 25, 36, 42, 47, 62], and a number of assessments of the likelihood of resultant subsea pipeline failure [44, 62] have also been carried out. Pipeline failure frequencies at different water depth regimes as a result of ice gouging in this study have been estimated on the basis of the historical ice gouge characteristics [2, 29] together with an analytical assessment [2, 44, 62] of their likelihood to damage a pipeline.

According to Weeks [62], a relationship between the expected probability of pipeline failure from ice gouging and ice gouging local characteristics may be expressed as follows:

$$N = e^{-kx} H_S \cdot F \cdot T \cdot L_P \cdot \sin\Phi \qquad \textbf{(2.2)}$$

Where:

N	=	Number of pipeline failures at burial depth of cover x (meters)
k	=	Inverse of mean scour depth (m^{-1})
x	=	Depth of cover (m)
H_S	=	Probability of pipeline failure given ice gouge impact or hit
F	=	Scour flux per km-yr
T	=	Exposure time (years)
L_P	=	Length of pipeline (km)
Φ	=	Gouge orientation (degrees) from pipeline centerline

For the present middle shelf depth location in the Chukchi, ice gouging is assumed to occur at a rate equal to 50% of that at inner shelf depth.

2.5.3 Strudel Scour

When water collects on top of the landfast ice, generally from rivers running into the Arctic seas, and drains through a hole in the ice, its hydrodynamic effect on the ocean floor below forms a depression which is called a strudel scour. Numerous studies have been conducted on strudel scour [25, 33, 35, 48], so that a prediction on the number of strudel scours per unit area can be made on the basis of historical data. Strudel scours are restricted to shallower water.

2.5.4 Upheaval Buckling

Upheaval buckling occurs in a pipeline as a result of its thermal expansion which causes it to buckle upwards to accommodate the extra length generated from thermal effects. Unfortunately, there appears to be no defensible analytical method for calculating the probability of upheaval buckling of Arctic subsea pipelines in general. Accordingly, upheaval buckling has been taken simply as a percentage of the strudel scour effects quantified in previous work [16, 17]. Assuming that upheaval buckling occurs 20% as often as strudel scour, the distribution shown in Table 2.10 can be derived. Upheaval buckling is expected to be independent of water depth; accordingly, the same values have been used for each water depth range. Other Arctic effects have been incorporated on the basis of values used in preceding studies [16, 17].

Table 2.10
Summary of Pipeline Unique Arctic Effect Inputs

CAUSE CLASSIFICATION 1972-2010 (Arctic)	Spill Size	Shallow Shelf			Inner Shelf			Middle Shelf		
		Frequency Increment per 10^5 km-year								
		Min	Mode	Max	Min	Mode	Max	Min	Mode	Max
Ice Gouging	S	0.0087	0.1054	1.2841	0.0108	0.1318	1.6051	0.0054	0.0659	0.8026
	M	0.0087	0.1054	1.2841	0.0108	0.1318	1.6051	0.0054	0.0659	0.8026
	L	0.0216	0.2635	3.2103	0.0270	0.3294	4.0128	0.0135	0.1647	2.0064
	H	0.0043	0.0527	0.6421	0.0054	0.0659	0.8026	0.0027	0.0329	0.4013
Strudel Scour	S	0.0110	0.0235	0.1381						
	M	0.0110	0.0235	0.1381						
	L	0.0276	0.0587	0.3452						
	H	0.0055	0.0117	0.0690						
Upheaval Buckling	S	0.00221	0.00469	0.02761	0.00221	0.00469	0.02761	0.00221	0.00469	0.02761
	M	0.00221	0.00469	0.02761	0.00221	0.00469	0.02761	0.00221	0.00469	0.02761
	L	0.00552	0.01174	0.06904	0.00552	0.01174	0.06904	0.00552	0.01174	0.06904
	H	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381
Thaw Settlement	S	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381
	M	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381
	L	0.00276	0.00587	0.03452	0.00276	0.00587	0.03452	0.00276	0.00587	0.03452
	H	0.00055	0.00117	0.00690	0.00055	0.00117	0.00690	0.00055	0.00117	0.00690
Other Arctic	S	0.00230	0.01359	0.14636	0.00141	0.01388	0.16466	0.00087	0.00729	0.08440
	M	0.00230	0.01359	0.14636	0.00141	0.01388	0.16466	0.00087	0.00729	0.08440
	L	0.00575	0.03398	0.36590	0.00353	0.03470	0.41164	0.00218	0.01823	0.21100
	H	0.00115	0.00680	0.07318	0.00071	0.00694	0.08233	0.00044	0.00365	0.04220

2.5.5 Thaw Settlement

Thaw settlement occurs when a permafrost lens or formation over which the pipeline was installed melts as a result of the heat generated by the pipeline and ceases to support the pipeline so that the pipeline overburden loads the pipeline and causes it to deflect downwards [39]. Although it is unlikely to occur in the Chukchi Sea, thaw settlement has conservatively been taken at 50% of the probability of strudel scours.

2.5.6 Platform Arctic Unique Effects

This section covers potential causes of platform spills (other than LOWC'S, which are included under wells) that are uniquely associated with the Arctic, are ice forces and low temperature effects. Although the possibility that ice forces will cause spills varies greatly from facility to facility, some broad assumptions have been made in regard to the likelihood of spills being caused by ice force effects. Specifically, it was assumed that the platforms are designed for a 10,000 year return period with a reliability level of 96%, in accordance with the ISO 19906 Arctic Structures Reliability *Section 7.2.2.3* [34]. That is, 4% of the time, the 10,000 year return period ice force can cause a spill. Further, it was assumed that 85% of spills so caused are small and medium, with large and huge spills associated with the other 15%. In regards to facility low temperature, a percentage of historical facility releases was taken. Specifically, it was assumed that the facility low temperature effects will cause small and medium spills at a rate of 6% of that of total historical small and medium spills, and large and huge spills at a rate of 3% of that associated with large and huge historical spills. Finally, other Arctic unique causes were assumed to constitute another 5% of the sum of the above spill rates in each of the spill categories. Table 2.11 summarizes the resultant Arctic unique effect frequencies derived for platforms on a per well-year exposure basis.

Table 2.11
Summary of Platform Unique Arctic Effect Inputs

ARCTIC UNIQUE CAUSE	SPILL SIZE	Water Depth Middle Shelf Frequency Increment per 10^4 well-year Expected / *Mode*	REASON
Ice Force	SM	0.3256	Assumed 10,000 year return period ice force causes spill 4% of occurrences (96% reliability). 85% of the spills are SM.
		0.0765	
	LH	0.0575	
		0.0135	
Facility Low Temperature	SM	0.0855	Assumed fraction of Historical Equipment Failure release frequency with 6% for SM and 1% for LH spill sizes.
		0.0855	
	LH	0.0143	
		0.0143	
Other Arctic	SM	0.0205	5% of sum of above.
		0.0081	
	LH	0.0036	
		0.0014	

2.6 Historical Spill Size Distribution

Tables 2.12, 2.13, and 2.14 give the historical spill volume distributions obtained from available historical data. In each case, the mode was taken as the historical average spill size in each spill size category, while the high and low values were taken to be the upper and lower bounds of each spill size category. The Huge spill high values were chosen on the basis of the upper 90% confidence interval spill volumes in the databases.

Table 2.12
Historical Pipeline Spill Volume Distribution Parameters

Spill Size	Small Spills 50-99 bbl				Medium Spills 100-999 bbl				Large Spills 1000-9999 bbl				Huge Spills =>10000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected
Pipeline Diameter <= 10" Spill	50	58	99	71	100	226	999	485	1,000	4,436	9,999	5,279	10,000	14,423	20,000	14,880
Pipeline Diameter > 10" Spill	50	58	99	71	100	387	999	516	1,000	3,932	9,999	5,176	10,000	17,705	20,000	15,552

Table 2.13
Historical Platform Spill Volume Distribution Parameters

Spill Size	Small and Medium Spills 50-999 bbl				Large and Huge Spills =>1000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected
Platform Spill	50	158	999	452	1,000	6,130	10,000	5,631

Table 2.14
Historical LOWC Spill Volume Distribution Parameters

Spill Size	Small and Medium Spills 50-999 bbl				Large Spills 1000-9999 bbl				Spills 10000-149999 bbl				Spills =>150000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected
Well Spill	50	500	999	519	1,000	4,500	9,999	5,292	10,000	20,000	150,000	68,349	150,000	200,000	250,000	200,000

CHAPTER 3

PROJECT DEVELOPMENT SCENARIOS

3.1 Approaches to Project Development Scenarios

The Project is assumed to span water depths from shallow shelf to middle shelf depths, with pipelines connecting the current estimated locations to shore. For the purposes of the fault tree analysis utilized in this study, Project scenarios need to include the following characteristics for each year of the development scenario:

- Water depth distribution for pipelines.
- Physical quantities of individual components – including well drilling, production wells, platforms, and pipelines – on an annual basis in correspondence with the baseline data exposure factors.
- Annual oil production volumes.
- Other characteristics such as pipeline diameter or type of well drilled.

Table 3.1 shows the classification of development Scenarios by water depth range and operation type. The salient aspect of this classification is subdivision into water depth ranges among which Arctic hazard characteristics (such as ice gouging rates) may change. The following water depth categories are used for the Project:

- Shallow Shelf: < 10 meters
- Inner Shelf: 10 to 29 meters
- Middle Shelf: 30 to 60 meters

Table 3.1
Classification of Development Scenarios

PRINCIPAL ACTIVITY	WATER DEPTH (m)		
	SHALLOW SHELF(< 10)	INNER SHELF (10 to 29)	MIDDLE SHELF (30 to 60)
EXPLORATION	▪ Artificial island ▪ Drill barge ▪ Ice island	▪ Artificial island ▪ Drill ship (summer) ▪ Caisson	▪ Drill ship (summer) ▪ Semisubmersible (summer)
PRODUCTION	▪ Artificial island ▪ Caisson island	▪ Caisson island ▪ Gravity Base Structure (GBS)	▪ Caisson island ▪ Gravity Base Structure (GBS)
TRANSPORT	▪ Subsea pipeline	▪ Subsea pipeline	▪ Subsea pipeline ▪ Storage & tankers

In Table 3.1, an indication is given of the types of facilities that might be utilized in each of the principal types of oil and gas activities, exploration, production, or transportation. As will be seen in this chapter, current forecasts for development scenarios over the Project's 51 years of potential oil spill exposure exclude outer shelf and basin depth locations, in excess of 60 m. In general, the scenarios described in this chapter were developed to an appropriate level and type of detail to match the type of unit spill data and statistics available as a basis for the oil spill occurrence indicator quantification. The principal regions of interest within the study area is the Chukchi Sea Leased Area middle shelf depth location, shown earlier in Figure 1.2.

3.2 Project Development Scenarios

As a basis for the current analysis, the geographic distribution of the facilities and its variation over the life of the development is required, in order to effectively incorporate the effects of Arctic operations on the oil spill occurrences. The information in this chapter is based on the more detailed Project description obtained from BOEM and given in Appendix A. Table 3.2 summarizes the key quantity parameters of the Chukchi Project scenario. The facility quantities are hypothetical, and not based on any operator's plan. No facilities are assumed in the outer shelf and basin depth region; all platforms are in the middle shelf depth region. Onshore facilities are mentioned in Table 3.2 for completeness, but excluded in the analysis.

Table 3.2
Summary of Scenario Results for Development of Anchor A and Satellite A-2 Oil Fields

Element	Range	Comment
Marine Seismic Surveys	4-12	Will vary based on number of operators
Geohazard Surveys	10-16	Will vary based on number of operators
Geotechnical Surveys	10-16	Will vary based on number of operators
Platforms	8	
Exploration and Delineation Wells	30-40	Includes dry holes and additional unsuccessful wells on other Chukchi prospects drilled after a success
Production Wells	400-457	457 required to produce all the recoverable oil
Service Wells	80-92	20% of production wells
Onshore Oil Pipeline (miles)	300-320	Longer distance may be required for rerouting
Onshore Gas Pipeline (miles)	300-320	Longer distance may be required for rerouting
Offshore Oil Pipeline (miles)	190-210	Miles will vary based on location of actual prospects
Offshore Gas Pipeline (miles)	190-210	Miles will vary based on location of actual prospects
Total Oil Production (Bbbl)	4.0-4.3	
Total Gas Production (Tcfg)	2.0-2.2	
Peak Oil Rate (bbl/day)	558,702	Limited by Excess Capacity in TAPS
Peak Gas Rate (MCF/day)	314,618	
New Pipelines to Shore	2	1 oil trunkline, followed by 1 gas trunkline in same corridor near Wainwright
New Shore Base	1	Near Wainwright
New processing facility	1	At new shorebase
New waste facility	1	At new shorebase
Drilling fluids from exploration and delineation wells (tons)	2850-3800	475 tons/well, with 80% recycled drilling fluid from intermediate and production strings
Rock cuttings discharge for exploration and delineation wells (tons)	18,000 – 24,000	600 tons/well
Discharges for Service and Production Wells (tons)	0	Drilling fluid and rock cuttings will be disposed of in service wells or barged to shore for disposal.
Flights per week during production phase	56-168	1 to 3 flights per platform per day
Boat Trips per week during production phase	8-16	1 to 2 trips per platform per week
Years of Activity	70-74	Final gas production may be truncated for economic reasons

Table 3.3 summarizes the Project development scenario including its temporal development from Year 3 to Year 53 after which time it is forecast to cease oil production. For items such as exploration and field delineation well drilling, the actual number of wells drilled in a given year were needed, since the statistics of LOWC spills are on a per well drilled exposure unit. For items that continue from year to year, such as production wells or subsea pipelines, both the annual incremental and the cumulative total are needed. Specifically, the following facility quantities were estimated and distributed as shown in Table 3.3:

- Exploration wells drilled – annual.
- Delineation wells drilled – annual.
- Production platforms – annual and cumulative.
- Production wells – annual increment and cumulative number.
- Pipeline lengths for <= 10”, and >10”, and total – annual increment and cumulative pipeline length in service by water depth.
- Total Project oil production volumes – annual.

As noted above, these quantities match the type of unit spill data that are available through the historical analysis. For example, we have spill data by pipeline diameter only for lines <= and >10”, so a full spectrum of pipeline diameters would be redundant.

Table 3.4 gives the mainline pipeline route depth characteristics. Because Arctic hazards to pipelines are greatest in shallow water locations, the Icy Cape route which entails the most shallow water exposure was conservatively chosen for the subsequent analysis.

Table 3.3
Project Data (Years 3 to 54)

Year	Well Depth	Exploration Wells	Development Wells	Production Platforms				In-use Pipeline Length [miles]						Production MMbbl
				Platforms		Wells		Sum<=10"		Sum >10"		Sum All		
				Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	
3	Shallow Shelf													
	Inner Shelf													
	Middle Shelf	4												
	Total	4												
4	Shallow Shelf													
	Inner Shelf													
	Middle Shelf	4												
	Total	4												
5	Shallow Shelf													
	Inner Shelf													
	Middle Shelf	4												
	Total	4												
6	Shallow Shelf													
	Inner Shelf													
	Middle Shelf	4												
	Total	4												
7	Shallow Shelf													
	Inner Shelf													
	Middle Shelf	4												
	Total	4												
8	Shallow Shelf													
	Inner Shelf													
	Middle Shelf	4												
	Total	4												
9	Shallow Shelf													
	Inner Shelf													
	Middle Shelf	4												
	Total	4												
10	Shallow Shelf									10	10	10	10	
	Inner Shelf									12	12	12	12	
	Middle Shelf		1	1	1	1	1			138	138	138	138	1.475
	Total		1	1	1	1	1			160	160	160	160	1.475
11	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		13		1	13	14				138		138	20.646
	Total		13		1	13	14				160		160	20.646
12	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		18		1	18	32	2	2		138	2	140	47.060
	Total		18		1	18	32	2	2		160	2	162	47.060
13	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		20	1	2	20	52	2	4	5	143	7	147	74.560
	Total		20	1	2	20	52	2	4	5	165	7	169	74.560
14	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		26		2	26	78	2	6		143	2	149	106.482
	Total		26		2	26	78	2	6		165	2	171	106.482
15	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		20		2	20	98	2	8		143	2	151	124.856
	Total		20		2	20	98	2	8		165	2	173	124.856
16	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		23	1	3	23	121	4	12	5	148	9	160	142.809
	Total		23	1	3	23	121	4	12	5	170	9	182	142.809

Table 3.3 ~ Continued ~

Year	Well Depth	Exploration Wells	Development Wells	Production Platforms: Platforms		Production Platforms: Wells		In-use Pipeline Length [miles]: Sum<=10"		Sum >10"		Sum All		Production MMbbl
				Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	
17	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		29		3	29	150	2	14		148	2	162	165.459
	Total		29		3	29	150	2	14		170	2	184	165.459
18	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		21		3	21	171	4	18		148	4	166	173.831
	Total		21		3	21	171	4	18		170	4	188	173.831
19	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		23	1	4	23	194	2	20	5	153	7	173	181.871
	Total		23	1	4	23	194	2	20	5	175	7	195	181.871
20	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf	4	27		4	27	221	2	22		153	2	175	193.134
	Total	4	27		4	27	221	2	22		175	2	197	193.134
21	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf	4	18		4	18	239	2	24		153	2	177	190.310
	Total	4	18		4	18	239	2	24		175	2	199	190.310
22	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf	4	22	1	5	22	261	2	26	5	158	7	184	191.860
	Total	4	22	1	5	22	261	2	26	5	180	7	206	191.860
23	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		30		5	30	291	4	30	20	178	24	208	204.420
	Total		30		5	30	291	4	30	20	200	24	230	204.420
24	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		14	1	6	14	305		30		178		208	194.160
	Total		14	1	6	14	305		30		200		230	194.160
25	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		27		6	27	332		30		178		208	203.926
	Total		27		6	27	332		30		200		230	203.926
26	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		15		6	15	347		30		178		208	195.478
	Total		15		6	15	347		30		200		230	195.478
27	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		16	1	7	16	363		30	5	183	5	213	189.812
	Total		16	1	7	16	363		30	5	205	5	235	189.812
28	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		18		7	18	381		30		183		213	186.852
	Total		18		7	18	381		30		205		235	186.852
29	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		14		7	14	395		30		183		213	178.893
	Total		14		7	14	395		30		205		235	178.893
30	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		16	1	8	16	411		30	5	188	5	218	174.988
	Total		16	1	8	16	411		30	5	210	5	240	174.988
31	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		18		8	18	429		30		188		218	175.106
	Total		18		8	18	429		30		210		240	175.106

Table 3.3 ~ Continued ~

Year	Well Depth	Exploration Wells	Development Wells	Production Platforms: Platforms		Production Platforms: Wells		In-use Pipeline Length [miles]: Sum<=10"		Sum >10"		Sum All		Production MMbbl
				Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	
32	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		13		8	13	442		30		188		218	169.592
	Total		13		8	13	442		30		210		240	169.592
33	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		14		8	14	456	-2	28		188	-2	216	164.220
	Total		14		8	14	456	-2	28		210	-2	238	164.220
34	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf		1		8	1	457	-2	26		188	-2	214	135.932
	Total		1		8	1	457	-2	26		210	-2	236	135.932
35	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-2	24		188	-2	212	108.688
	Total				8		457	-2	24		210	-2	234	108.688
36	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-2	22		188	-2	210	84.452
	Total				8		457	-2	22		210	-2	232	84.452
37	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-4	18		188	-4	206	65.503
	Total				8		457	-4	18		210	-4	228	65.503
38	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-2	16		188	-2	204	50.676
	Total				8		457	-2	16		210	-2	226	50.676
39	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-4	12	-5	183	-9	195	39.222
	Total				8		457	-4	12	-5	205	-9	217	39.222
40	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-2	10		183	-2	193	30.278
	Total				8		457	-2	10		205	-2	215	30.278
41	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-2	8		183	-2	191	23.266
	Total				8		457	-2	8		205	-2	213	23.266
42	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-2	6	-5	178	-7	184	17.910
	Total				8		457	-2	6	-5	200	-7	206	17.910
43	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-2	4		178	-2	182	13.692
	Total				8		457	-2	4		200	-2	204	13.692
44	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457	-4			178	-4	178	10.314
	Total				8		457	-4			200	-4	200	10.314
45	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		457			-5	173	-5	173	7.868
	Total				8		457			-5	195	-5	195	7.868
46	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8	-347	110				173		173	5.794
	Total				8	-347	110				195		195	5.794

Table 3.3 ~ Continued ~

Year	Well Depth	Exploration Wells	Development Wells	Production Platforms: Platforms		Production Platforms: Wells		In-use Pipeline Length [miles]: Sum<=10"		In-use Pipeline Length [miles]: Sum >10"		In-use Pipeline Length [miles]: Sum All		Production MMbbl
				Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	Incr.	Cum.	
47	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		110				173		173	4.318
	Total				8		110				195		195	4.318
48	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		110			-5	168	-5	168	3.154
	Total				8		110			-5	190	-5	190	3.154
49	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		110				168		168	2.220
	Total				8		110				190		190	2.220
50	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		110				168		168	1.545
	Total				8		110				190		190	1.545
51	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		110				168		168	0.994
	Total				8		110				190		190	0.994
52	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		110				168		168	0.538
	Total				8		110				190		190	0.538
53	Shallow Shelf										10		10	
	Inner Shelf										12		12	
	Middle Shelf				8		110			-5	163	-5	163	0.236
	Total				8		110			-5	185	-5	185	0.236
54	Shallow Shelf									-10		-10		
	Inner Shelf									-12		-12		
	Middle Shelf			-8		-110				-163		-163		
	Total			-8		-110				-185		-185		

Table 3.4
Length of Offshore Sales Oil Pipeline in Each Depth Category

Offshore Sales Oil Pipeline (160 Miles)	Shallow Shelf <10 m	Inner Shelf 10 to 29 m	Middle Shelf 30 to 60 m
Icy Cape	10 miles	12 miles	138 miles
In Between	8 miles	8 miles	144 miles
Point Belcher	4 miles	6 miles	150 miles

CHAPTER 4

FAULT TREE ANALYSIS FOR ARCTIC OIL SPILL FREQUENCIES

4.1 General Description of Fault Tree Analysis

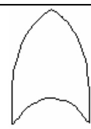
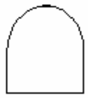
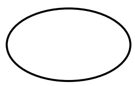
Fault trees are a method for modeling the occurrence of failures. They are used when an adequate history is not available to provide failure statistics. Developed initially by Rasmussen for the U.S. Nuclear Regulatory Commission in the early 1970s [61], fault trees have become a popular risk analytic tool for predicting risks, assessing relative risks, and quantifying comparative risks [6, 10, 12, 13]. In 1976, Bercha first used fault trees to quantify oil spill probabilities in the Canadian Beaufort Sea for the Canadian Department of the Environment [12, 13]. In the present study they are used for the transformation of historical oil spill statistics for non-Arctic regions to predictive oil spill statistics for Arctic regions in the study area.

4.2 Fault Tree Methodology

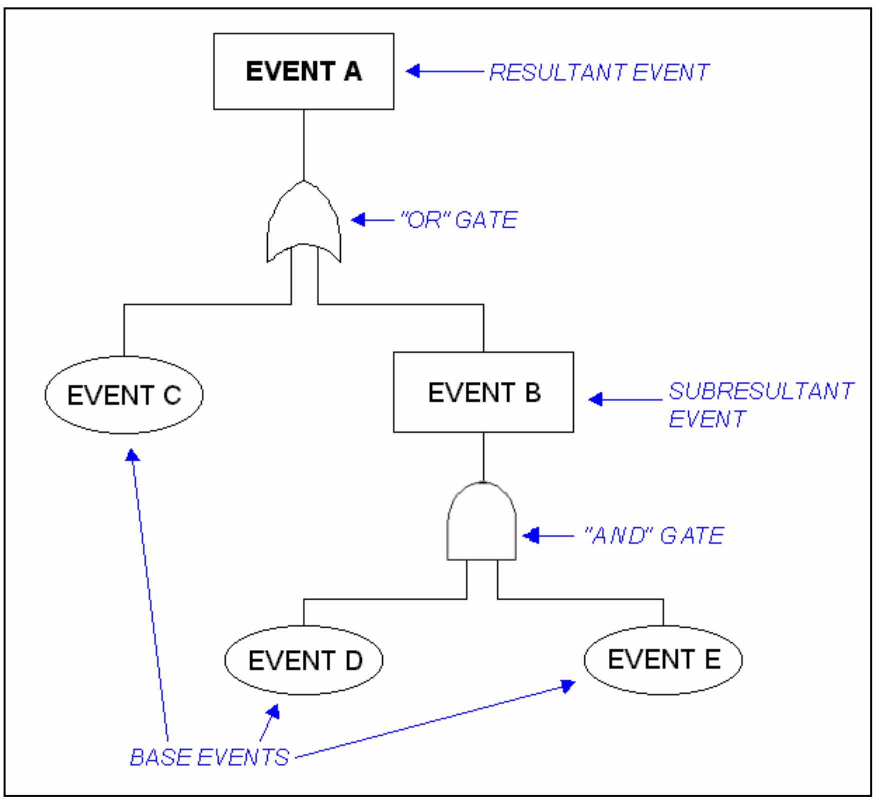
4.2.1 Fault Tree Analysis Basics

The basic symbols used in the graphic depiction of simple (as used here) fault tree networks are illustrated in Figure 4.1(a). As may be seen, the two types of symbols designate logic gates and event types. The basic fault tree building blocks are the events and associated sub-events, which form a causal network. The elements linking events are the AND and OR gates, which define the logical relationship among events in the network. The output event from an OR gate occurs if any one or more of the input events to the gate occurs. The output event from an AND gate occurs only if all the input events occur simultaneously.

The basic structure of a fault tree is illustrated in Figure 4.1(b). Because of their connection through an AND gate, Event D and Event E must both occur for the resultant Event B to occur. An OR gate connects Events B and C; therefore, the occurrence of either one or both of Events B and C results in the occurrence of the resultant Event A. As may be seen, the principal fault tree structures are easy to apply; however, the representation of complex problems often requires very large fault trees, which become more difficult to analyze and require more advanced techniques such as minimal cut-set analysis [1, 6, 10]. For the present application, a simple system connected through OR gates only will be used.

SYMBOL	DESCRIPTION
A. LOGIC	
	EITHER / OR GATE
	AND GATE
B. EVENT	
	RESULTANT EVENT
	BASIC EVENT

(a) Basic Fault Tree Symbols



(b) Basic Fault Tree Structure

Figure 4.1
Fault Tree Basics

Computationally, the probability of input events joined through an AND gate are multiplied to calculate the probabilities of the output event. The probabilities of input events joined through an OR gate are added to calculate the probability of the output event. The relevant equations and associated assumptions may be summarized as follows:

For AND Gate:
$$P = \prod_{n}^{i=1} P_i \quad (4.1a)$$

Example: Output Event Probability = P_x
Input Events failure probabilities, P_1, P_2, ….

$$P_x = P_1(P_2)(P_3) \quad (4.1b)$$

For OR Gate:
$$P = 1 - \prod_{n}^{i=1}(1 - P_i) \quad (4.2a)$$

Example: Output Event Probability = P_y
Input Event failure probabilities, P_1, P_2, …

$$P_y = 1 - \prod_{n}(1 - P_1)(1 - P_2)(1 - P_3)$$
$$P_y = P_1 + P_2 + P_3;\ for\ P_i \le 0.1 \quad (4.2b)$$

In more complex fault trees, it is necessary to assure that base events which affect more than one fault tree branch are not numerically duplicated. This is done through the use of minimal cut-set theory [1, 6]. However, as indicated earlier, the fault trees used in this study are sufficiently simple in structure and level of detail to exclude the requirement of using minimal cut-set theory in their computation algorithms.

4.2.2 Current Application of Fault Trees

Figure 4.2 illustrates a two-tier fault tree that can be used to develop pipeline large spill frequencies for the Arctic study area from the historical frequencies. Note that this example is illustrative of the process only, and does not correspond to the same numerical values used in computations later. The type of fault tree shown, to be used extensively later, is a relatively simple fault tree showing the resultant event, the spill, generated from a series of subresultant events corresponding to the pipeline spill causal classification, such as that shown in Table 2.3. The upper tier of numbers (marked "H") below each of the events in the fault tree represents the historical frequency (per 100,000 km-yr) while the lower one (marked "A") represents the modified frequency for Arctic operations. As these fault trees are composed entirely of OR gates, the computation of resultant events is quite simple – consisting of the addition of the probabilities of events at each level of the fault tree to obtain the resultant probability at the next higher value.

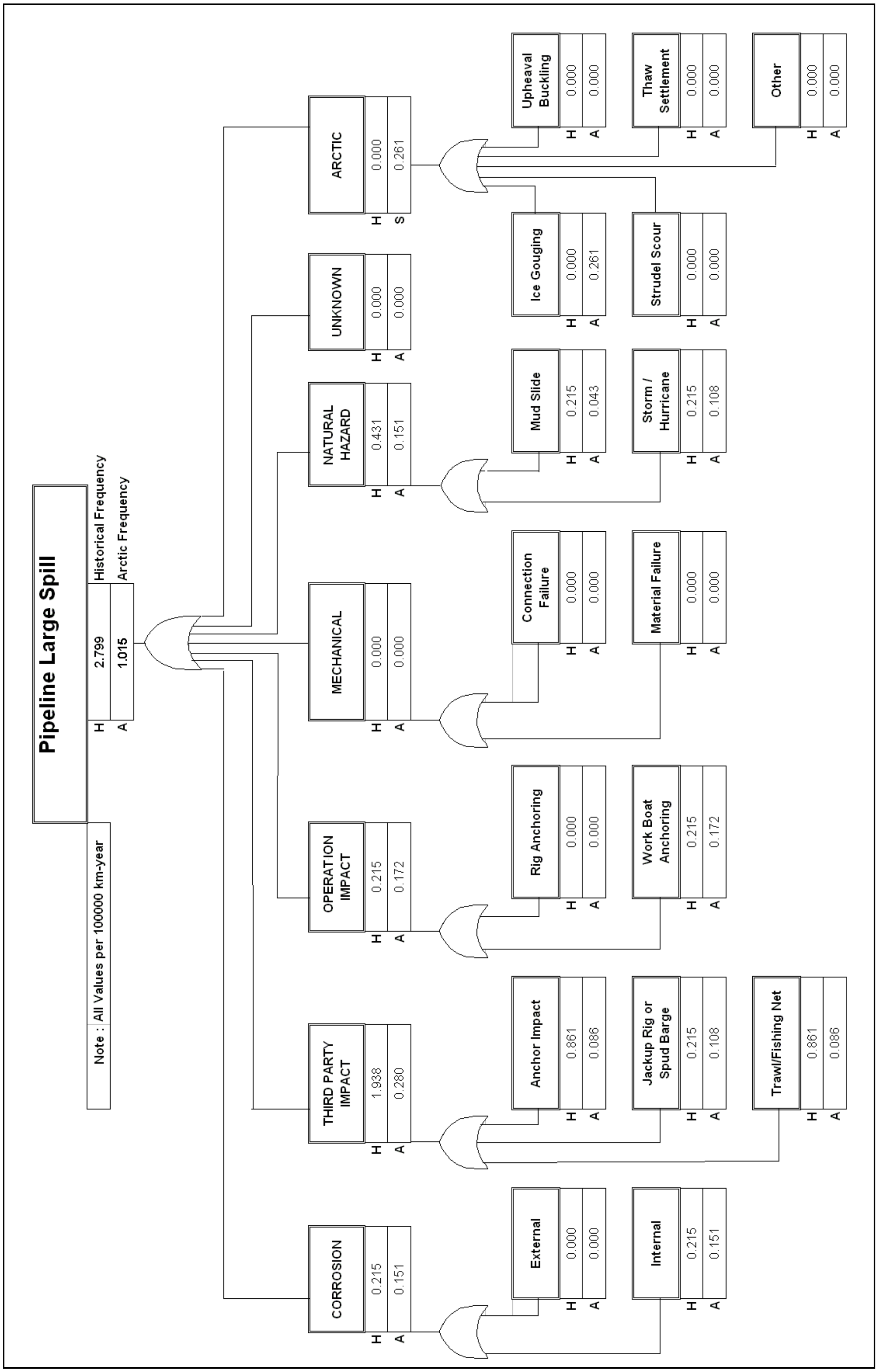


Figure 4.2
Example of Fault Tree to Transform Historical (GOM and PAC) to Arctic Spill Frequencies[1]

[1] The input data used here are only illustrative and do not represent the inputs used later in this study.

For example, to obtain the “Natural Hazard” Arctic (“A”) probability of 0.151, add 0.043 and 0.108. Essentially, the fault tree resultant (top event) shows that the Arctic frequency of spills (for the example pipeline category, location, and spill size) is approximately 1 in 100,000 km-yr or 1.015 x 10^{-5}/km-yr. The non-Arctic historical frequency for this spill size, by comparison, is 2.799 x 10^{-5}/km-yr, or approximately 2.8 times higher. Both frequencies are for illustrative purposes only.

4.2.3 Monte Carlo Simulation

A type of numerical simulation, called Monte Carlo simulation [9] can be used to obtain the outcome of a set of interactions for equations in which the independent variables are described by distributions of any arbitrary form. The Monte Carlo simulation is a systematic method for selecting values from each of the independent variable distributions and computing all valid combinations of these values to obtain the distribution of the dependent variable. Naturally, this is done utilizing a computer, so that thousands of combinations can be rapidly computed and assembled to give the output distribution.

Consider the example of the following equation:

$$\boldsymbol{X = X_1 + X_2} \qquad \textbf{(4.3)}$$

Where X is the dependent variable (such as the resultant spill frequency) and X_1 and X_2 are base event probabilities joined through an OR gate. Suppose now that X_1 and X_2 are some arbitrary distributions that can be described by a collection of values x_1 and x_2. What we do in the Monte Carlo process, figuratively, is to put the collection of the X_1 values into one hat, the X_1 hat, and the same for the X_2 values – into an X_2 hat. We then randomly draw one value from each of the hats and compute the resultant value of the dependent variable, X, using Equation 4.3. This is done several thousand times. Thus, a resultant or dependent variable distribution, X, is estimated from the computations of all valid combinations of the independent variables (X_1 and X_2).

Generally, the resultant can be viewed as a cumulative distribution function as illustrated in Figure 4.3. Such a cumulative distribution function (CDF) is also a measure of the accuracy or, conversely, the variance of the distribution. As can be seen from this figure, if the distribution is a vertical line, no matter where one draws on the vertical axis, the same value of the variable will result – that is, the variable is a constant. At the other extreme, if the variable is completely random then the distribution will be represented as a diagonal straight line between the minimum and maximum value. Intermediate qualitative descriptions of the randomness of the variable follow from inspection of the CDF in Figure 4.3.

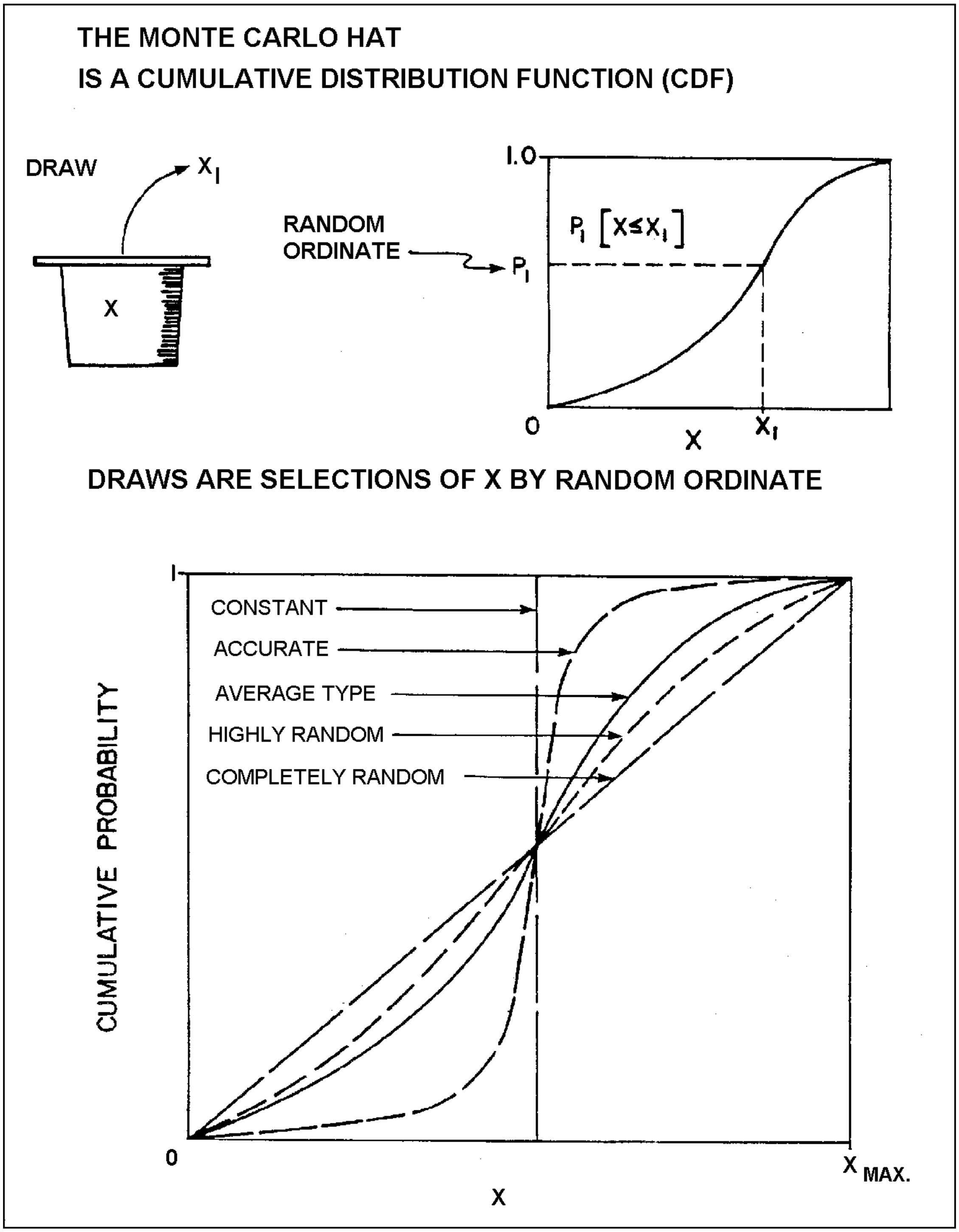


Figure 4.3
Monte Carlo Technique Schematic

There are two other important concepts related to the CDF that enter into Monte Carlo modeling: namely, auto-correlation and cross-correlation. Suppose the variables X_1 can vary only within a specified interval over the simulation time increment. Then, after the first random draw, the next draw would be restricted within certain limits of the initial draw simply as a result of the physical restrictions of the problem. Such a restriction is represented as an auto-correlation coefficient. Now, suppose that not only are the X_1 restricted, but also the X_2. Suppose further, however, that given a certain X_1, a restriction were placed on the range of X_2 associated with that X_1. Say, only small X_1 could associate with the full range of X_2, while large X_1 could only be associated with certain lower X_2. Then, such a relationship would be expressed as a cross-correlation factor and certain limits would be imposed for the drawing on both X_1 and associated X_2. In the present analysis, all distributed variables are considered to be independent – so that auto and cross-correlations need not be invoked.

4.2.4 Distribution Derived from Historical Data for Monte Carlo Analysis

In order to model the variability of the base data and its distribution through the Arctic effects, using the Monte Carlo approach, an appropriate distribution needs to be derived. As in the previous study [16, 17], a Triangular Distribution was selected.

According to [31, 43], the Triangular Distribution is typically used as a descriptor of a population for which there is only limited sample data, as is the current case. The distribution is based on a knowledge of a minimum and maximum, which was derived from the historical data here, and an educated guess as to what the modal value might be. Here, the modal value was chosen to be a function of the average historical value, as given in Equation 2.1. Despite being a simplistic description of a population, the Triangular Distribution is a very useful one for modeling processes where the relationship between variables is understood, but data are scarce.

Also, when combining several variables in a functional relationship utilizing numerical methods, as is done in Monte Carlo Simulation, the Triangular Distribution is a preferred one due to its simplicity and relatively accurate probabilistic resultant when evaluated by a large number of random draws, as occurs in the Monte Carlo process. The data used here typifies sparse data with a preferred or modal value and an easily identifiable maximum and minimum. Then, for the case of the simple upper and lower 100% confidence interval (called High and Low), the expected value ***E*** (or mean value) of the Triangular Distribution can be expressed as:

$$E = (High + Mode + Low) / 3 \qquad \textbf{(4.4)}$$

For maximum and minimum which are not at the 100% confidence interval level – such as those at 90% confidence levels – a Monte Carlo computation is used to evaluate the expected value of each distribution, giving results somewhat different from Equation 4.4. Based on the historical data presented earlier in Tables 2.4, 2.7, and 2.10, the Triangular Distribution expected values computed from the low, mode, and high values at 90% confidence intervals are given in Tables 4.1, 4.2, and 4.3, for pipelines, platforms, and wells respectively. The high and low values were calculated as described in Section 2.2.

Table 4.1
Pipeline Spill Frequency Distribution Properties

GOM and PAC OCS Pipeline Spills, Categorized 1972-2010		Low Factor	High Factor	Frequency spill per 10^5 km-years				
By Diameter	*By Spill Size*			Historical	Low	Mode	High	Expected
<= 10"	Small	0	2.81	4.9390	0	0.9384	13.8786	6.1956
	Medium	0	2.81	8.5310	0	1.6209	23.9722	10.7014
	Large	0	2.81	3.1430	0	0.5972	8.8319	3.9426
	Huge	0	2.81	0.4490	0	0.0853	1.2617	0.5632
>10"	Small	0	2.81	3.5699	0	0.6783	10.0315	4.4782
	Medium	0	2.81	9.8173	0	1.8653	27.5866	12.3149
	Large	0	2.81	6.2474	0	1.1870	17.5551	7.8368
	Huge	0	2.81	1.7850	0	0.3391	5.0158	2.2391

Table 4.2
Platform Spill Frequency Distribution Properties

Spill Size	Frequency Unit	Low Factor	High Factor	Historical	Low	Mode	High	Expected
Small and Medium Spills (50-999 bbl)	Spill per 10^4 well-year	0	3	4.766	0.0000	0.0000	14.298	6.355
Large and Huge Spills (>= 1000 bbl)	Spill per 10^4 well-year	0	3	0.285	0.0000	0.0000	0.855	0.380

Table 4.3
LOWC Frequency Distribution Properties

Spill Size	Event	Frequency Unit	Low Factor	High Factor	Frequencies				
					Historical	Low	Mode	High	Expected
Small and Medium Spills 50-999 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.028	0.012	0.028	0.043	0.028
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	1.330	0.584	0.698	2.708	1.530
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.283	0.124	0.227	0.498	0.299
Large Spills 1,000-9,999 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.011	0.005	0.011	0.017	0.011
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.539	0.237	0.283	1.097	0.620
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.115	0.050	0.092	0.202	0.122
Small, Medium and Large Spills 50-9,999 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.039	0.017	0.039	0.060	0.039
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	1.869	0.821	0.981	3.805	2.150
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.398	0.174	0.320	0.700	0.421
Spill 10,000-149,999 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.007	0.003	0.007	0.011	0.007
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.350	0.154	0.184	0.713	0.403
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.075	0.033	0.060	0.131	0.079
Spill =>150,000 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.005	0.002	0.005	0.007	0.004
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.217	0.095	0.114	0.442	0.250
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.046	0.020	0.037	0.081	0.049

4.2.5 Approaches to Assessment of Arctic Spill Frequency Variability

The method for assessment of Arctic spill frequency variability consists of systematically perturbing the variability of all the causal events, plus that of the Arctic unique effects. In this approach, the non-Arctic variable distribution is multiplied by an adjustment or correction distribution to obtain the Arctic variable distribution.

4.3 Pipeline Fault Tree Analysis

4.3.1 Arctic Pipeline Spill Causal Frequency Distributions

The effects of the Arctic environment and operations are reflected in the effect on facility failure rates in two ways; namely, through "Modified Effects", those changing the frequency component of certain fault contributions such as anchor impacts which are common to both Arctic and temperate zones, and through "Unique Effects" or additive elements such as ice gouging which are unique to the Arctic offshore environment. Table 4.4 shows the frequency modifications (in %) and frequency increment additions (per 10^5 km-yr) developed for Arctic pipelines for different spill sizes throughout the three relevant water depth ranges. The right hand column of the table gives a summary of the reasoning behind the effects. For the Arctic unique effects, both the expected value (from Table 2.9) and the median value, determined through the Monte Carlo analysis, are given. The median values differ from the expected values due to skewness of the distributions introduced through the assigned values of the upper and lower bounds (Table 2.9). The following comments can be made for each of the causes described:

- *External corrosion* – Due to the low temperature, limited biological and lowered chemical effects are expected. Coatings will be state of art and high level of quality control will be used during pipeline installation resulting in high integrity levels of coating to prevent external corrosion.
- *Internal corrosion* – Additional (above historical levels) inspection or smart pigging is anticipated.
- *Anchor impact* – The very low traffic densities of third party shipping in the area justify a 50% reduction in anchor impact expectations on the pipeline.
- *Jack-up rig or spud barges* – Associated or other operations are going to be substantially more limited than they are in the historical data population in the GOM and PAC OCS.
- *Trawl/Fishing net* – Less fishing is expected in the Chukchi Sea.
- *Rig anchoring* – Although it is anticipated that no marine traffic except possibly icebreakers will occur during the ice season, an increased traffic density during the four month open water season to resupply the platforms is expected, justifying only a 20% decrease in this failure cause.
- *Work boat anchoring* – The same applies to work boat anchoring as to rig anchoring.
- *Mechanical connection failure or material failure* – No change was made to account for Arctic effects.

Table 4.4
Pipeline Arctic Effect Derivation Summary

CAUSE CLASSIFICATION 1972-2010	Spill Size	Shallow Shelf	Inner Shelf	Middle Shelf	Reason
		Historical Expected Frequency Change %			
CORROSION					
External	All	(30)	(30)	(30)	Low temperature and bio effects. Extra smart pigging.
Internal	All	(30)	(30)	(30)	Extra smart pigging.
THIRD PARTY IMPACT					
Anchor Impact	All	(50)	(50)	(50)	Low traffic.
Jackup Rig or Spud Barge	All	(50)	(50)	(50)	Low facility density.
Trawl/Fishing Net	All	(30)	(40)	(50)	Low fishing activity. Less bottom fishing in deeper water.
OPERATION IMPACT					
Rig Anchoring	All	(20)	(20)	(20)	Low marine traffic during ice season (8 months).
Work Boat Anchoring	All	(20)	(20)	(20)	Low work boat traffic during ice season (8 months).
MECHANICAL					
Connection Failure	All				
Material Failure	All				
NATURAL HAZARD					
Mud Slide	All	(90)	(80)	(80)	Gradient low. Mud slide potential (gradient) increases with water depth.
Storm/ Hurricane	All	(70)	(70)	(60)	Fewer severe storms.
		Freq. Increment per 10^5 km-year			
		Expected	Expected	Expected	
		Mode	Mode	Mode	
ARCTIC UNIQUE					
Ice Gouging	S	0.5411	0.6763	0.3382	Ice gouge failure rate calculated using exponential failure distribution for 2.5-m cover, 0.2-m average gouge depth, 4 gouges per km-yr flux. Spill size Distribution explained in text Section 2.5.2. Inner shelf depth has 0.8 as many gouges as shallow shelf depth. Middle shelf depth 1/2 of the frequency for the inner shelf depth.
		0.1054	0.1318	0.0659	
	M	0.5411	0.6763	0.3382	
		0.1054	0.1318	0.0659	
	L	1.3527	1.6908	0.8454	
		0.2635	0.3294	0.1647	
	H	0.2705	0.3382	0.1691	
		0.0527	0.0659	0.0329	
Strudel Scour	S	0.0645			Only in shallower water. Average frequency of 4 scours/mile^2 and 100 ft of bridge length with 10% conditional P/L failure probability. The same spill size distribution as above.
		0.0235			
	M	0.0645			
		0.0235			
	L	0.1613			
		0.0587			
	H	0.0323			
		0.0117			
Upheaval Buckling	S	0.0129	0.0129	1.0129	All water depth. The failure frequency is 20% of that of Strudel Scour.
		0.0047	0.0047	0.0047	
	M	0.0129	0.0129	0.0129	
		0.0047	0.0047	0.0047	
	L	0.0323	0.0323	0.0323	
		0.0117	0.0117	0.0117	
	H	0.0065	0.0065	0.0065	
		0.0023	0.0023	0.0023	
Thaw Settlement	S	0.0065	0.0065	0.0065	All water depth. The failure frequency is 10% of that of Strudel Scour.
		0.0023	0.0023	0.0023	
	M	0.0065	0.0065	0.0065	
		0.0023	0.0023	0.0023	
	L	0.0161	0.0161	0.0161	
		0.0059	0.0059	0.0059	
	H	0.0032	0.0032	0.0032	
		0.0012	0.0012	0.0012	
Other Arctic	S	0.0625	0.0696	0.0358	To be assessed as 10% of all arctic effects.
		0.0136	0.0139	0.0073	
	M	0.0625	0.0696	0.0358	
		0.0136	0.0139	0.0073	
	L	0.1532	0.1739	0.0894	
		0.0340	0.0347	0.0182	
	H	0.0312	0.0348	0.0179	
		0.0068	0.0069	0.0036	

- *Mudslide* – A relatively low gradient resulting in limited mudslide potential is anticipated. A gradual increase in the mudslide potential (reflected by smaller decreases in failure frequency) ranging from 90% for shallow shelf water to 80% in middle and outer shelf water was included to account for the anticipated increase in gradient as deeper waters are encountered.
- *Storms* – Considerably fewer severe storms are anticipated on an annual basis in the Arctic than in GOM or PAC, due to damping of the ocean surface by ice cover.
- *Arctic unique effects* – Arctic effects are effects which are unique to the Arctic and are not reflected in the historical fault tree itself. Arctic effects were discussed in detail in Chapter 2, Section 2.5. The discussion in that section is summarized in the right hand column of Table 4.4. The frequency increments in this table are given as both the "mode" values and the "expected" values. The mode values are the mode values given in Table 2.10. The expected values, however, are those calculated using the Monte Carlo method with the low, mode, and high values from Table 2.10, as inputs to the Monte Carlo. The expected or mean values are clearly considerably higher than the mode or most likely values. This lack of coincidence between expected and mode values is due to the skewness of the distribution.

Derivation of the Arctic effect distributions is accomplished through the construction of a secondary triangular distribution by which the historical causal frequency distributions are multiplied to provide the resultant Arctic effect distribution. This secondary distribution utilizes the value of mode adjustments from Table 4.4, with appropriate second order perturbations for the upper and lower 90% confidence interval bounds. Table 4.5 summarizes these Arctic effect distributions. For the Arctic modified effects, given in the top of the table, the secondary distribution is simply the frequency change used as the mode of the distribution, and 90% upper and lower confidence interval changes given under the Min and Max columns. For the Arctic unique effects, total frequency increments are given, with the upper confidence interval value at approximately 13 times the mode, and the lower bound value at approximately $^{1}/_{20}$ of the modal value in the case of S (small) spill Ice Gouging.

4.3.2 Arctic Pipeline Fault Tree Frequency Calculations

Incorporation of the frequency effects as variations in and additions to the historical frequencies can be represented in a fault tree, as shown for the large spill size for Arctic pipelines in Figure 4.4. In this figure, the historical frequency as well as that associated with shallow shelf, inner shelf, and middle shelf zones are shown under each of the event boxes. Each box is further split into two, for pipelines less than or equal to 10" diameter or greater than 10" diameter as represented in the historical database. Such fault trees were developed for all of the pipeline spill sizes.

The frequency calculation corresponding to the large spill size fault tree shown is in Figure 4.4. Consider the bottom line opposite totals. The table tells us that the total spill frequency for pipelines <=10" diameter was 3.943 (per 10^5 km-yr) historically. With the first and second order frequency changes attributable to Arctic effects, this frequency is reduced to 2.987 for middle shelf water. A similar reduction of failure frequencies for pipelines >10" is manifested in the right hand side of the FT resultants. Table 4.6 summarizes the expected values of the pipeline spill frequencies for the two pipeline diameters and for each spill size and water depth.

Table 4.5
Pipeline Arctic Effect Distribution Derivation Summary

CAUSE CLASSIFICATION 1972-2010	Spill Size	Shallow Shelf			Inner Shelf			Middle Shelf		
		Frequency Change %								
		Min	Mode	Max	Min	Mode	Max	Min	Mode	Max
CORROSION										
External	All	(90)	(30)	(10)	(90)	(30)	(10)	(90)	(30)	(10)
Internal	All	(90)	(30)	(10)	(90)	(30)	(10)	(90)	(30)	(10)
THIRD PARTY IMPACT										
Anchor Impact	All	(90)	(50)	(10)	(90)	(50)	(10)	(90)	(50)	(10)
Jackup Rig or Spud Barge	All	(90)	(50)	(10)	(90)	(50)	(10)	(90)	(50)	(10)
Trawl/Fishing Net	All	(90)	(30)	(10)	(90)	(40)	(10)	(90)	(50)	(10)
OPERATION IMPACT										
Rig Anchoring	All	(50)	(20)	(10)	(50)	(20)	(10)	(50)	(20)	(10)
Work Boat Anchoring	All	(50)	(20)	(10)	(50)	(20)	(10)	(50)	(20)	(10)
MECHANICAL										
Connection Failure	All									
Material Failure	All									
NATURAL HAZARD										
Mud Slide	All	(90)	(90)	(10)	(90)	(80)	(10)	(90)	(80)	(10)
Storm/ Hurricane	All	(90)	(70)	(10)	(90)	(70)	(10)	(90)	(60)	(10)
		Frequency Increment per 10^5 km-year								
ARCTIC UNIQUE										
Ice Gouging	S	0.0087	0.1054	1.2841	0.0108	0.1318	1.6051	0.0054	0.0659	0.8026
	M	0.0087	0.1054	1.2841	0.0108	0.1318	1.6051	0.0054	0.0659	0.8026
	L	0.0216	0.2635	3.2103	0.0270	0.3294	4.0128	0.0135	0.1647	2.0064
	H	0.0043	0.0527	0.6421	0.0054	0.0659	0.8026	0.0027	0.0329	0.4013
Strudel Scour	S	0.0110	0.0235	0.1381						
	M	0.0110	0.0235	0.1381						
	L	0.0276	0.0587	0.3452						
	H	0.0055	0.0117	0.0690						
Upheaval Buckling	S	0.00221	0.00469	0.02761	0.00221	0.00469	0.02761	0.00221	0.00469	0.02761
	M	0.00221	0.00469	0.02761	0.00221	0.00469	0.02761	0.00221	0.00469	0.02761
	L	0.00552	0.01174	0.06904	0.00552	0.01174	0.06904	0.00552	0.01174	0.06904
	H	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381
Thaw Settlement	S	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381
	M	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381	0.00110	0.00235	0.01381
	L	0.00276	0.00587	0.03452	0.00276	0.00587	0.03452	0.00276	0.00587	0.03452
	H	0.00055	0.00117	0.00690	0.00055	0.00117	0.00690	0.00055	0.00117	0.00690
Other Arctic	S	0.00230	0.01359	0.14636	0.00141	0.01388	0.16466	0.00087	0.00729	0.08440
	M	0.00230	0.01359	0.14636	0.00141	0.01388	0.16466	0.00087	0.00729	0.08440
	L	0.00575	0.03398	0.36590	0.00353	0.03470	0.41164	0.00218	0.01823	0.21100
	H	0.00115	0.00680	0.07318	0.00071	0.00694	0.08233	0.00044	0.00365	0.04220

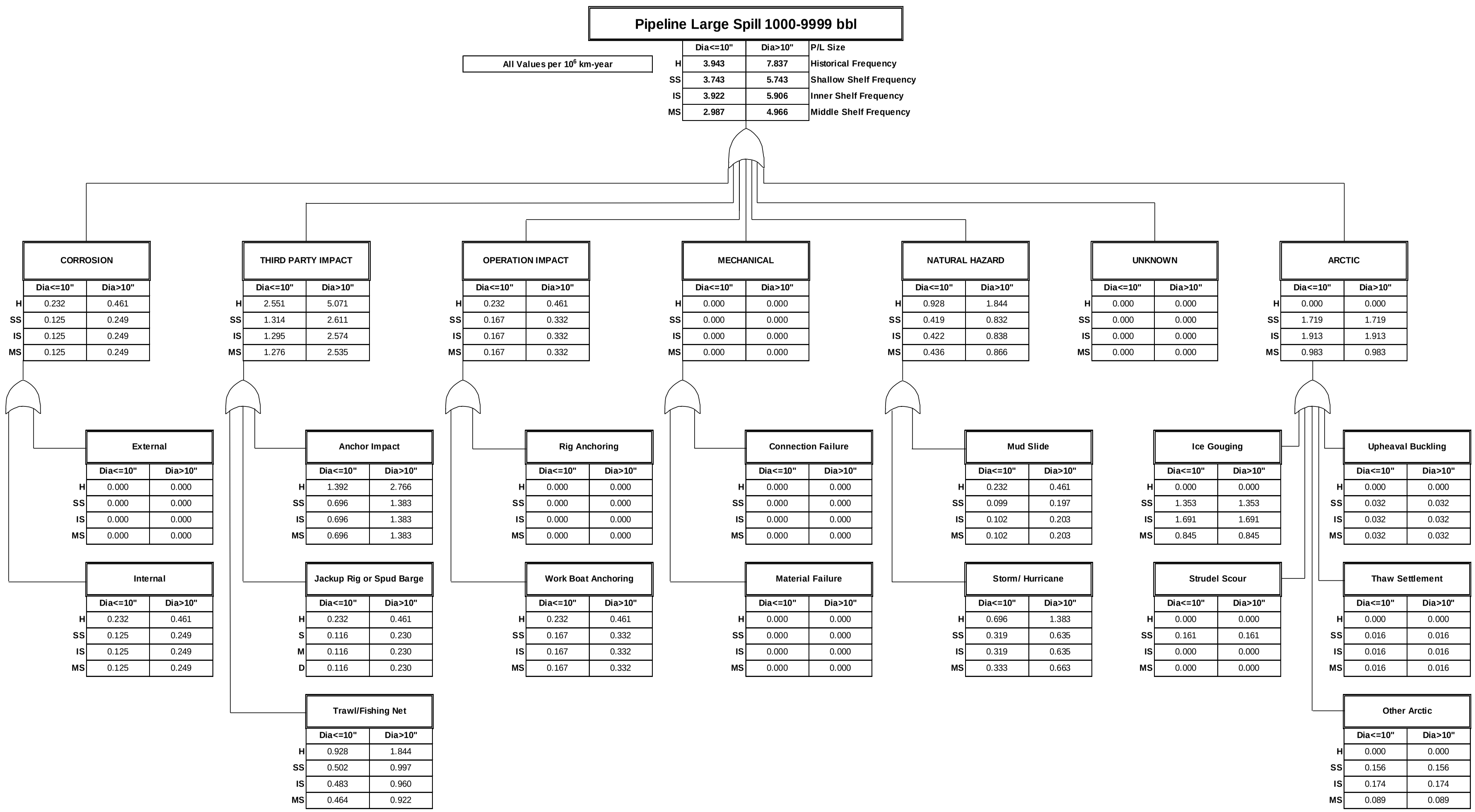


Figure 4.4
Large Spill Frequencies for Arctic Pipeline

Table 4.6
Expected Value Summary of Arctic Pipeline Spill Frequencies

Pipeline Spill Size	Pipeline Diameter <=10"				Pipeline Diameter >10"			
	Historical Frequency spills per 10^5 km-year	Arctic Frequency			Historical Frequency spills per 10^5 km-year	Arctic Frequency		
		Shallow Shelf	Inner Shelf	Middle Shelf		Shallow Shelf	Inner Shelf	Middle Shelf
Small Spills: 50-99 bbl	6.196	4.168	4.246	3.933	4.478	3.203	3.281	2.952
Medium Spills: 100-999 bbl	10.701	6.699	6.778	6.507	12.315	7.606	7.685	7.429
Large Spills: 1,000-9,999 bbl	3.943	3.743	3.922	2.987	7.837	5.743	5.906	4.966
Huge Spills: =>10,000 bbl	0.563	0.633	0.670	0.483	2.239	1.494	1.523	1.335

4.4 Platform Fault Tree Analysis

4.4.1 Arctic Platform Spill Causal Frequency Distributions

Table 4.7 summarizes the variations in the modified and unique Arctic effect inputs for platforms. As for pipeline unique effects, both the Triangular Distribution expected and modal values are given. All platforms are expected to be in middle shelf depth water.

The first two modified cause classifications, equipment failure and human error were reduced by 30 and 20%, respectively, primarily as a result of the state-of-the-art engineering, construction, and operational standards and practices expected. Collisions were reduced by 40% based on low vessel traffic expectations. As before, storms tend to be less severe in the Arctic, and certainly during the ice season would have limited impact on the facility, resulting in a 60% reduction in hurricane causes. However, weather in general, including very low temperatures, have been increased by 20%.

Unique effects are also included. Increments in facility spills were attributed to ice force, low temperature effects, and unknown effects which were taken as a percentage of the other unique Arctic effects. Ice force effect calculations were based on the 1/10,000 year ice force causing spills, predominantly small and medium. Ice forces are also considered to increase as a contributor to oil spill occurrences with water depth, due to the increasing severity of ice loads as one moves towards the edge of the landfast ice zone with increasing water depth. Increase of low temperature effects with water depth was estimated as 10% of historical process facility spill rates.

Changes in frequency distribution attributable to Arctic effects were calculated using the secondary effect probability distribution, as was done for pipelines. Table 4.8 summarizes the principal distribution parameters for both the Arctic modified and Arctic unique effect distributions.

4.4.2 Arctic Platform Fault Tree Spill Frequency Calculations

Figure 4.5 shows the fault tree developed for Arctic platform spills for the middle shelf depth zones for small and medium (SM), and large and huge spill (LH) sizes in accordance with [15]. Again, the fault tree gives the historical value, together with the calculated values for middle shelf depth water. Tables 4.9 and 4.10 show the frequency calculations for platforms for small and medium and large and huge spill sizes, respectively. Table 4.11 summarizes the historical and derived Arctic expected values of platform spill frequencies.

Table 4.7
Platform Arctic Effect Derivation Summary

CAUSE CLASSIFICATION 1972 - 2010 (no LOWC)	Spill Size	Historical Expected Frequency Change % Middle Shelf	Reason
EQUIPMENT FAILURE	All	(30)	State of the art now, High QC, High Inspection and Maintenance Requirements
HUMAN ERROR	All	(20)	More qualified personnel
COLLISION	All	(40)	Very low traffic density.
WEATHER	All	20	Cold Temperatures, cycling
HURRICANE	All	(60)	Less severe storms. More intensity in deeper water.
ARCTIC UNIQUE	Spill Size	Freq. Increment per 10^4 well-year Expected / Mode	Reason
Ice Force	SM	0.3256	Assumed 10,000 year return period ice force causes spill 4% of occurrences (96% reliability). 85% of the spills are SM.
		0.0765	
	LH	0.0575	
		0.0135	
Facility Low Temperature	SM	0.0855	Assumed fraction of Historical Equipment Failure release frequency with 6% for SM and 1% for LH spill sizes.
		0.0855	
	LH	0.0143	
		0.0143	
Other Arctic	SM	0.0205	5% of sum of above.
		0.0081	
	LH	0.0036	
		0.0014	

Table 4.8
Platform Arctic Effect Distribution Derivation Summary

CAUSE CLASSIFICATION 1972 - 2010 (no LOWC)	Spill Size	Middle Shelf Frequency Change % Min	Mode	Max
EQUIPMENT FAILURE	All	(60)	(30)	(10)
HUMAN ERROR	All	(60)	(20)	(10)
COLLISION	All	(60)	(40)	(10)
WEATHER	All	10	20	30
HURRICANE	All	(90)	(60)	(10)
ARCTIC UNIQUE	Spill Size	Frequency Increment per 10^4 well-year		
Ice Force	SM	0.0077	0.0765	0.7650
	LH	0.0014	0.0135	0.1350
Facility Low Temperature	SM	0.0428	0.0855	0.1283
	LH	0.0071	0.0143	0.0214
Other Arctic	SM	0.0025	0.0081	0.0447
	LH	0.0004	0.0014	0.0078

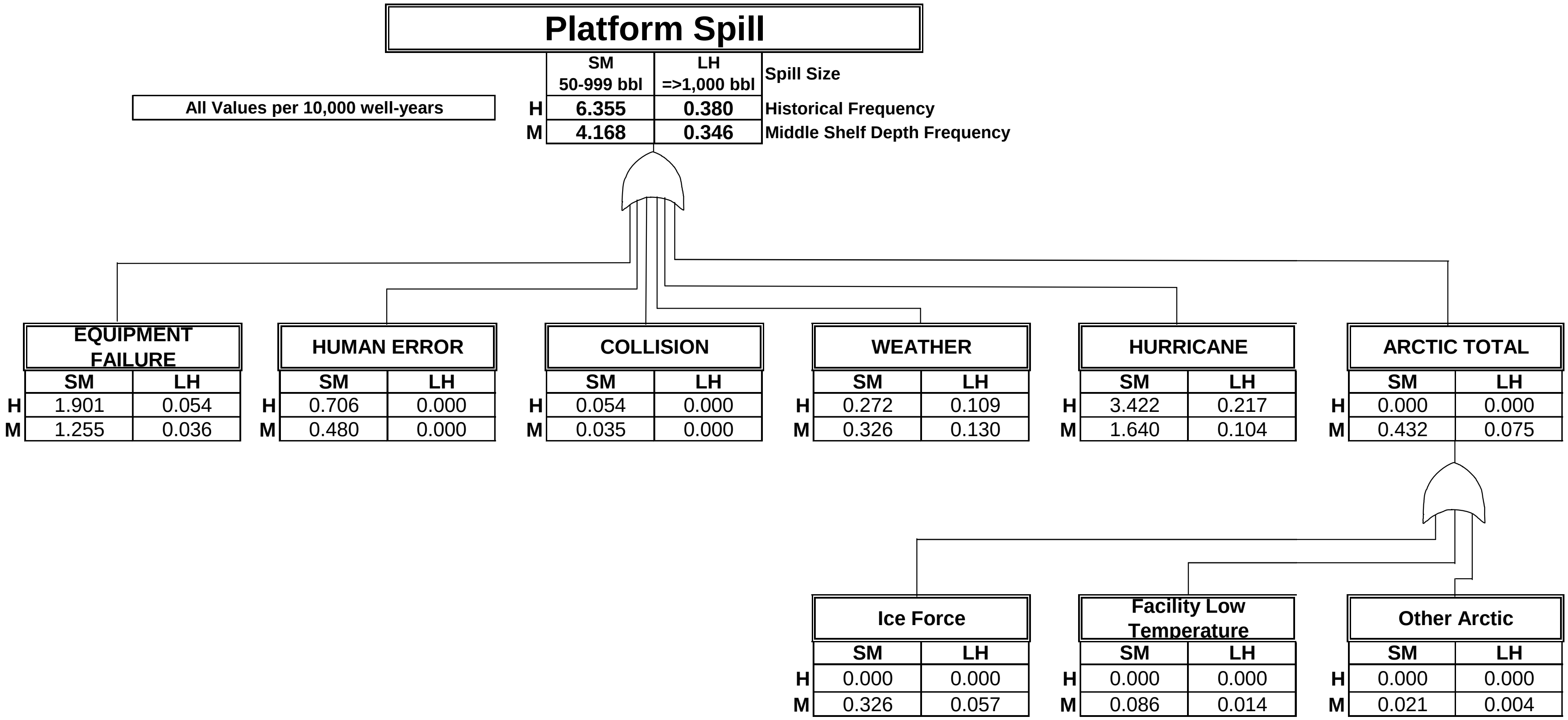


Figure 4.5
Spill Frequencies Platform Fault Tree

Table 4.9
Arctic Platform Small and Medium Spill Frequencies

CAUSE CLASSIFICATION 1972 - 2010 no LOWC)	SMALL AND MEDIUM SPILLS 50-999 bbl				
			Middle Shelf		
	HISTORICAL DISTRIBUTION %	FREQUENCY spills per 10^4well-year	Frequency Change	New Frequency	New Distribution %
EQUIPMENT FAILURE	29.91	1.901	(0.646)	1.255	30.12
HUMAN ERROR	11.11	0.706	(0.226)	0.480	11.53
COLLISION	0.85	0.054	(0.020)	0.035	0.83
WEATHER	4.27	0.272	0.054	0.326	7.82
HURRICANE	53.85	3.422	(1.782)	1.640	39.35
TOTAL	100.00	6.355	(2.618)	3.736	89.64
Ice Force			0.326	0.326	7.81
Facility Low Temperature			0.086	0.086	2.05
Other Arctic			0.021	0.021	0.49
ARCTIC TOTAL			0.432	0.432	10.36
TOTAL ALL	100.00	6.355	(3.187)	4.168	100.00

Table 4.10
Arctic Platform Large and Huge Spill Frequencies

CAUSE CLASSIFICATION 1972 - 2010 (no LOWC)	LARGE AND HUGE SPILLS => 1,000 bbl				
			Middle Shelf		
	HIST. DISTRIBUTION %	FREQUENCY spills per 10^4well-year	Frequency Change	New Frequency	New Distribution %
EQUIPMENT FAILURE	14.29	0.054	(0.018)	0.036	10.38
HUMAN ERROR					
COLLISION					
WEATHER	28.57	0.109	0.022	0.130	37.71
HURRICANE	57.14	0.217	(0.113)	0.104	30.13
TOTAL	100.00	0.380	(0.110)	0.270	78.22
Ice Force			0.057	0.057	16.62
Facility Low Temperature			0.014	0.014	4.13
Other Arctic			0.004	0.004	1.03
ARCTIC TOTAL			0.075	0.075	21.78
TOTAL ALL	100.00	0.380	(0.035)	0.346	100.00

Table 4.11
Arctic Platforms Spill Frequency Expected Value Summary

Platform Spill Size	Historical Frequency spills per 10^4 well-year	Arctic Frequency
		Middle Shelf
SMALL AND MEDIUM SPILLS 50-999 bbl	6.355	4.168
LARGE AND HUGE SPILLS =>1,000 bbl	0.380	0.346

4.5 Loss of Well Control (LOWC) Arctic Frequency Analysis

4.5.1 LOWC Arctic Effects

The historical data, as described in Chapter 2, were modified for each well type, spill size, and water depth range for Arctic effects (on historical values), as described in Table 4.12. No Arctic unique effects were introduced for LOWC.

4.5.2 Arctic LOWC Spill Frequency Calculation

Table 4.13 gives the details of the frequency calculation for LOWC. No fault tree was required here, as only base events with no causal distributions were modeled for each case. The modifications given in Table 4.12 were applied to historical values to yield the values summarized in Table 4.13.

4.6 Spill Volume Distributions

Tables 4.14, 4.15, and 4.16 summarize the spill volume distribution parameters for each facility type, including the expected value that was calculated utilizing a Monte Carlo calculation. The spill volume parameters were derived from the historical data described in Section 2.7. No Arctic effects are factored into the spill volume values.

Table 4.12
LOWC Fault Tree Analysis Arctic Effect Summary

Spill Size	Event	Frequency Unit	Historical Expected Frequency Change % *Middle Shelf*	Reason
Small and Medium Spills 50-999 bbl	Production Well	spill per 10^4 well-year	(30)	State of the art, High QC, High Inspection and Maintenance standard
	Exploration Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
	Development Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
Large Spills 1,000-9,999 bbl	Production Well	spill per 10^4 well-year	(30)	State of the art, High QC, High Inspection and Maintenance standard
	Exploration Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
	Development Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
Spill 10,000-149,999 bbl	Production Well	spill per 10^4 well-year	(30)	State of the art, High QC, High Inspection and Maintenance standard
	Exploration Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
	Development Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
Spill >=150,000 bbl	Production Well	spill per 10^4 well-year	(30)	State of the art, High QC, High Inspection and Maintenance standard Safety culture dedicated to avoid large spills in Arctic
	Exploration Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
	Development Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support

Table 4.13
Arctic LOWC Frequencies

Spill Size	Event	Frequency Unit	Historical Frequency	Frequency Change *Middle Shelf*	New Frequency *Middle Shelf*
Small and Medium Spills 50-999 bbl	Production Well	spill per 10^4 well-year	0.028	(0.008)	0.019
	Exploration Well Drilling	spill per 10^4 wells	1.530	(0.153)	1.377
	Development Well Drilling	spill per 10^4 wells	0.299	(0.030)	0.269
Large Spills 1,000-9,999 bbl	Production Well	spill per 10^4 well-year	0.011	(0.003)	0.008
	Exploration Well Drilling	spill per 10^4 wells	0.620	(0.062)	0.558
	Development Well Drilling	spill per 10^4 wells	0.122	(0.012)	0.109
Spill 10,000-149,999 bbl	Production Well	spill per 10^4 well-year	0.007	(0.002)	0.005
	Exploration Well Drilling	spill per 10^4 wells	0.403	(0.040)	0.362
	Development Well Drilling	spill per 10^4 wells	0.079	(0.008)	0.071
Spill >=150,000 bbl	Production Well	spill per 10^4 well-year	0.004	(0.001)	0.003
	Exploration Well Drilling	spill per 10^4 wells	0.250	(0.025)	0.225
	Development Well Drilling	spill per 10^4 wells	0.049	(0.005)	0.044

Table 4.14
Pipeline Spill Volume Parameters

Spill Size	Small Spills 50-99 bbl				Medium Spills 100-999 bbl				Large Spills 1000-9999 bbl				Huge Spills >=10000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected
Pipelines Diameter <= 10" Spill	50	58	99	71	100	226	999	485	1000	4436	9999	5279	10000	14423	20000	14880
Pipelines Diameter > 10" Spill	50	58	99	71	100	387	999	516	1000	3932	9999	5176	10000	17705	20000	15552

Table 4.15
Platform Spill Volume Parameters

Spill Size	Small and Medium Spills 50-999 bbl				Large and Huge Spills >=1000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected
Platform Spill	50	158	999	452	1000	6130	10000	5631

Table 4.16
LOWC Spill Volume Parameters

Spill Size	Small and Medium Spills 50-999 bbl				Large Spills 1000-9999 bbl				Spills 10000-149999 bbl				Spills >=150000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected
Well Spill	50	500	999	519	1000	4500	9999	5292	10000	20000	149999	68349	150000	200000	250000	200000

CHAPTER 5

OIL SPILL OCCURRENCE INDICATOR QUANTIFICATION

5.1 Definition of Oil Spill Occurrence Indicators

Four primary oil spill occurrence indicators (generally referred to as "spill indicators" after this) were quantified in this study. These are as follows:

- Frequency in spills per 1,000 years.
- Frequency in spills per 10^9 barrels produced in each year.
- Spill index, the product of spill frequency and associated average spill size.
- Life of field indicators.

The spill indicators defined above are subdivided for the Project as follows:

- By water depth (3 depths).
- By facility type (3 types).
- By spill size (4 sizes).
- By year (3 to 53, which is 51 years inclusive).

The above combinations translate into 36 sets of spill indicators per year. Given that these are calculated for each year, with the scenario lasting for 51 years, gives 1,836 sets of indicators. In this chapter, we will present and describe the salient results of the indicator evaluation.

5.2 Oil Spill Occurrence Indicator Calculation Process

The oil spill occurrence indicator calculation process is shown in the flow chart originally given in Figure 1.3, and again presented as Figure 5.1. This chapter discusses the spill occurrence indicator calculations as shown in the right hand column ("Spill Occurrence") in Figure 5.1. Previous chapters covered the balance of the items in that figure.

Essentially, this chapter addresses the combining of the development scenarios described in Chapter 3 with the unit-spill frequency distributions presented in Chapter 4 to provide measures of oil spill occurrence, the oil spill indicators for the Project. Although the calculation is complex because of the many combinations considered (approximately 1,800), in principle, it is a simple process of accounting. Essentially, the quantities of potential oil spill sources are multiplied by their appropriate unit oil spill frequency to give the total expected spill distributions. To develop the probability distributions by the Monte Carlo process, each of the 1,000 combinations needs to be sampled, in this case a sampling of 500 iterations was carried out for each combination studied. This translates into roughly 9 million arithmetic operations to generate the Monte Carlo results.

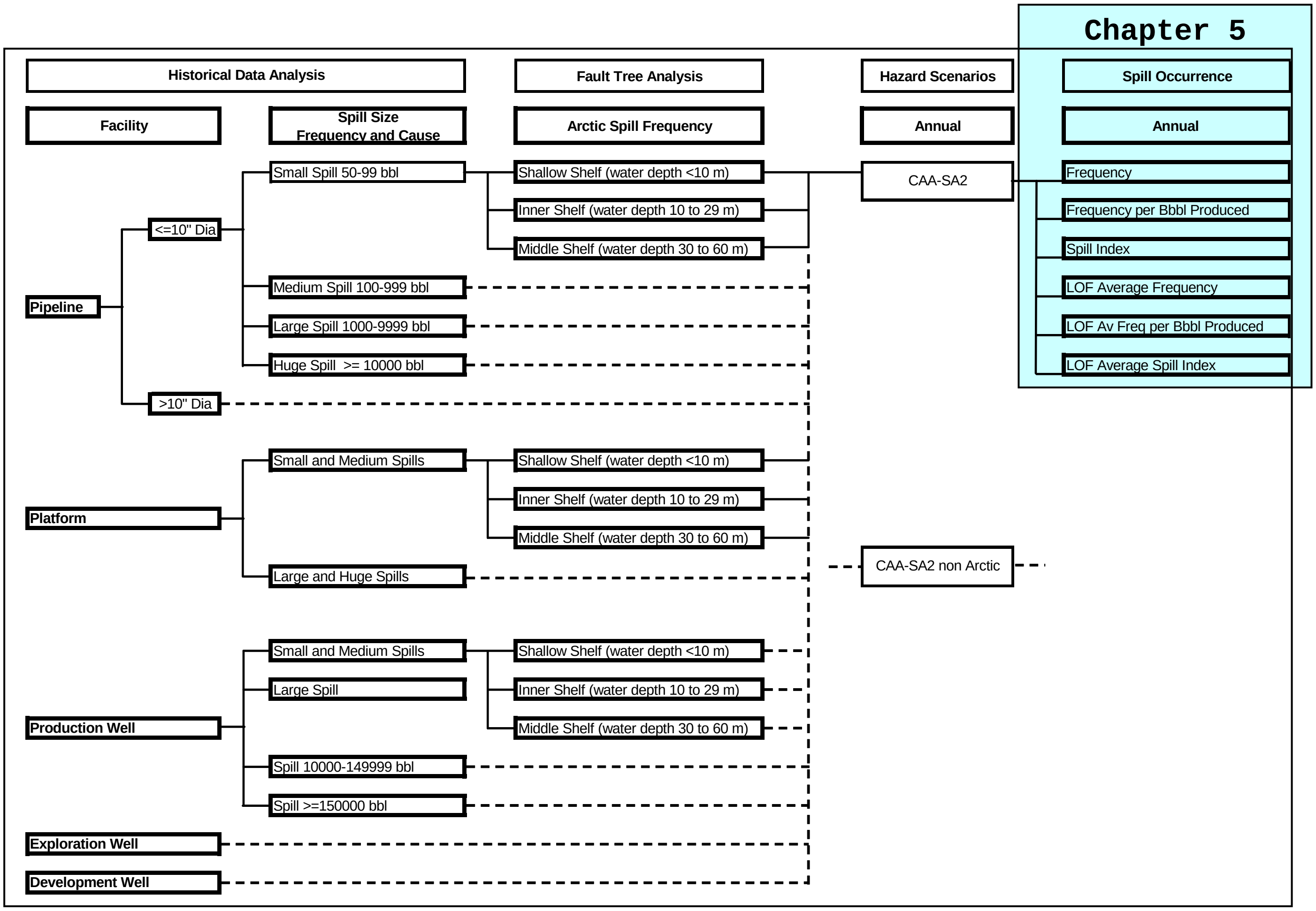


Figure 5.1
Calculation Flow Chart

5.3 Summary of Project Oil Spill Occurrence Indicators

5.3.1 Project Oil Spill Occurrence Indicators

Each of the principal annual total oil spill occurrence indicators including those for the pipelines, platforms, and wells for each year is given in Figures 5.2, 5.3, and 5.4 for the principal spill size categories.

As can be seen, each of these figures spans the development scenario from year 3 to 53, as described earlier in Table 3.3. Further, each of the indicators has been subdivided into three segments for each year, those corresponding to spills 50-999 bbl (small and medium), spills 1,000-9,999 bbl (large), and spills >=10,000 bbl (huge). It should be noted that the spill frequency associated with each spill size is only the shaded increment shown in each of the bars. The horizontal axis gives Project years starting in Year 3 the first year with spill potential. Thus, for example, for the year 33, small and medium spills are approximately 220 per thousand years. Next, in that year, large spills are approximately 38 per thousand years, as shown in the second bar increment (i.e., 258 – 220 = 38).

Finally, the top increment corresponds to huge spills, and is approximately 12 per thousand years. The same form of presentation applies for the spills per 10^9 barrels produced and for the spill index shown in Figures 5.3 and 5.4. For years in which no production exists (3 to 9), the spills per 10^9 barrels produced are not applicable. The spills per 10^9 barrels produced continue to rise exponentially to the final production year (53), because the facility quantities (and hence spill rate) remain relatively high, while production volumes decrease considerably for each of the last few years. Clearly, the spill index (Figure 5.4) is dominated by the huge spills. The reader should note that following this detailed presentation of the spill indicators in separate figures, all three spill indicators will be given in one figure in order to conserve space and make the report a little more concise.

Spill indicators by facility type were also quantified. All three spill indicators for pipelines are shown in Figure 5.5. Figure 5.6 shows the spill indicators for platforms (only for the two spill size categories available from the base data [15]), and Figure 5.7 shows the spill indicators for drilling of wells and producing wells. Numerous conclusions can be drawn from the comparison of these spill indicators. For example, it can be seen that the major contributors to spill frequency are platforms (Figure 5.6), as in earlier studies [16]. The largest of the facility spill expectations, as represented by spill index, are also the platforms.

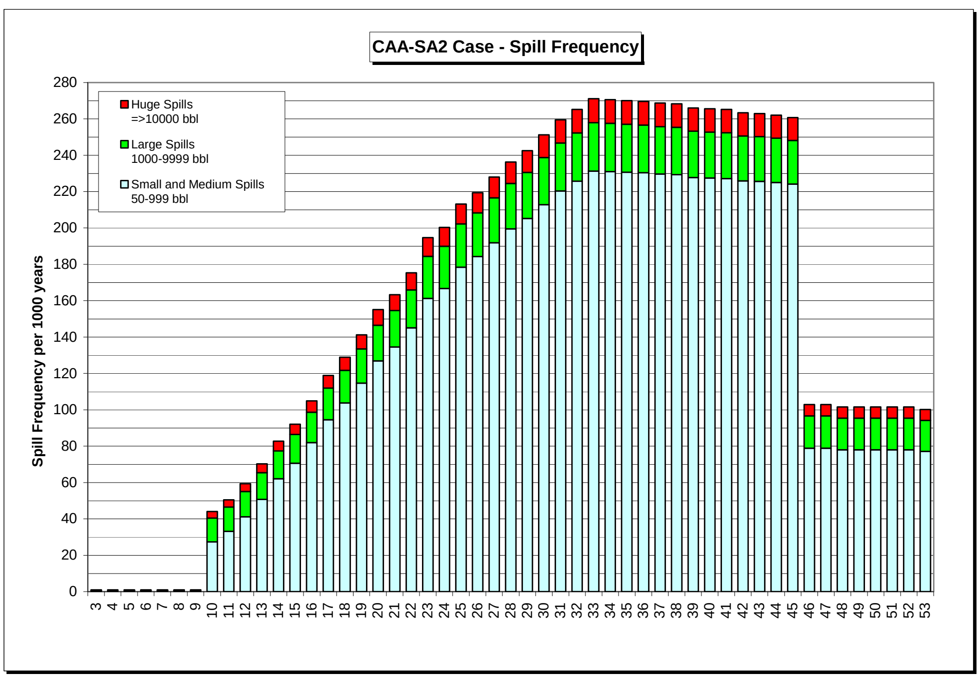


Figure 5.2
Project Spill Frequency per 1,000 Years

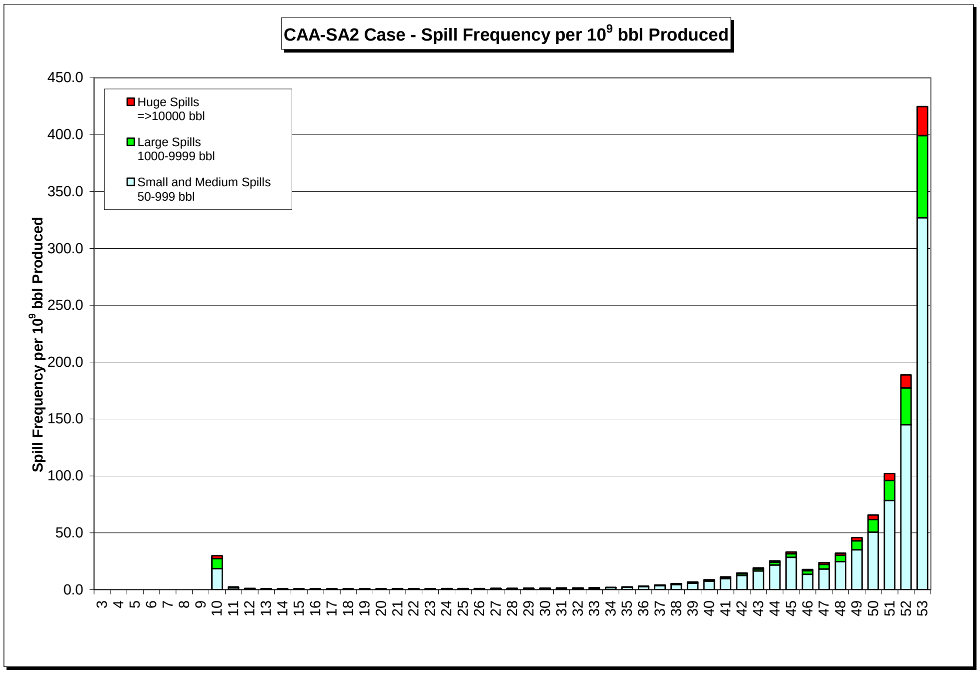


Figure 5.3
Project Spill Frequency per 10^9 Barrels Produced

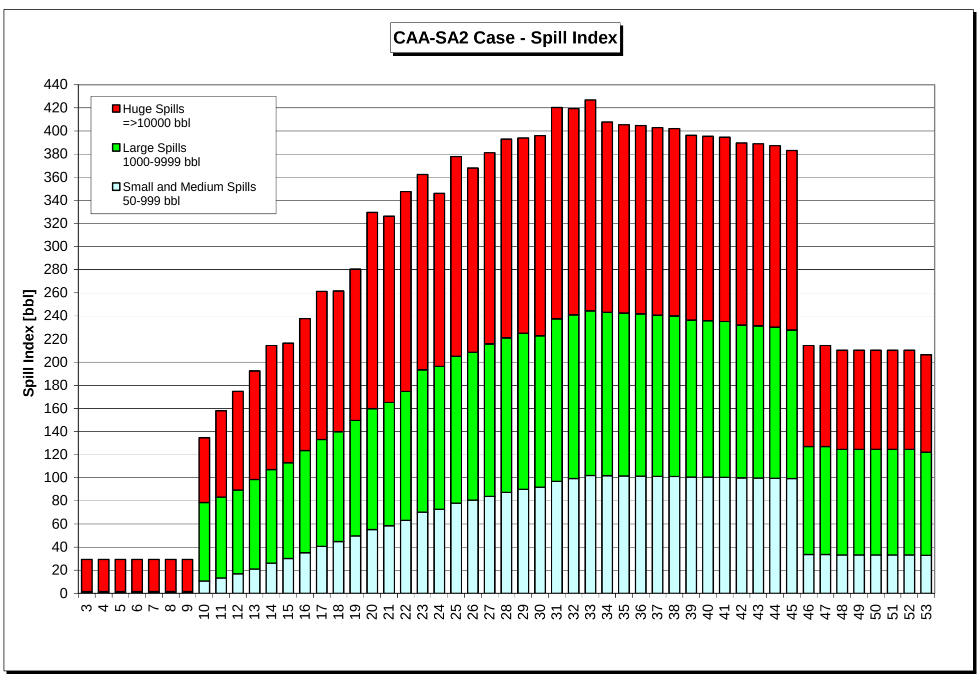


Figure 5.4
Project Spill Index

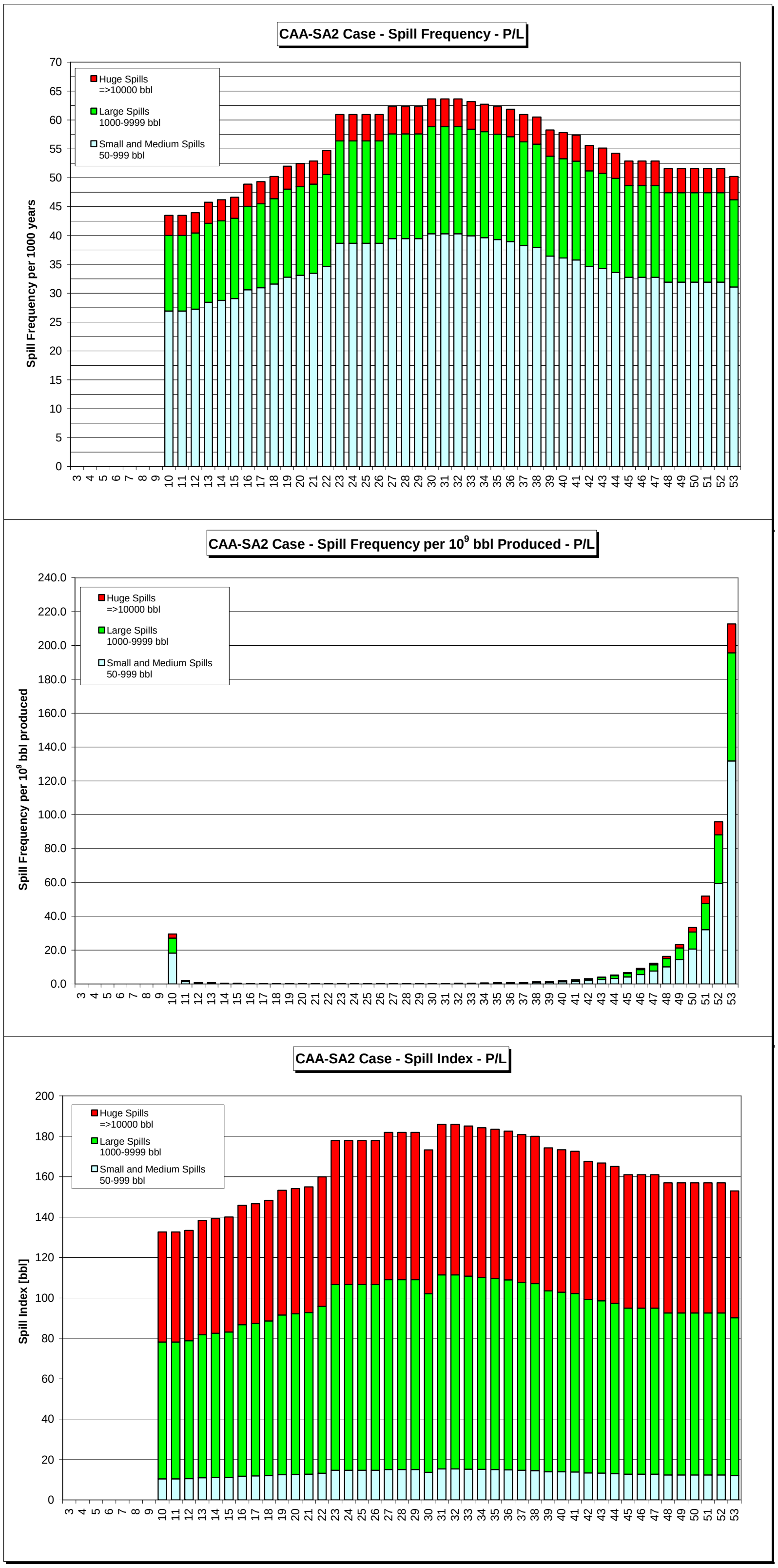


Figure 5.5
Project Indicators – Pipeline

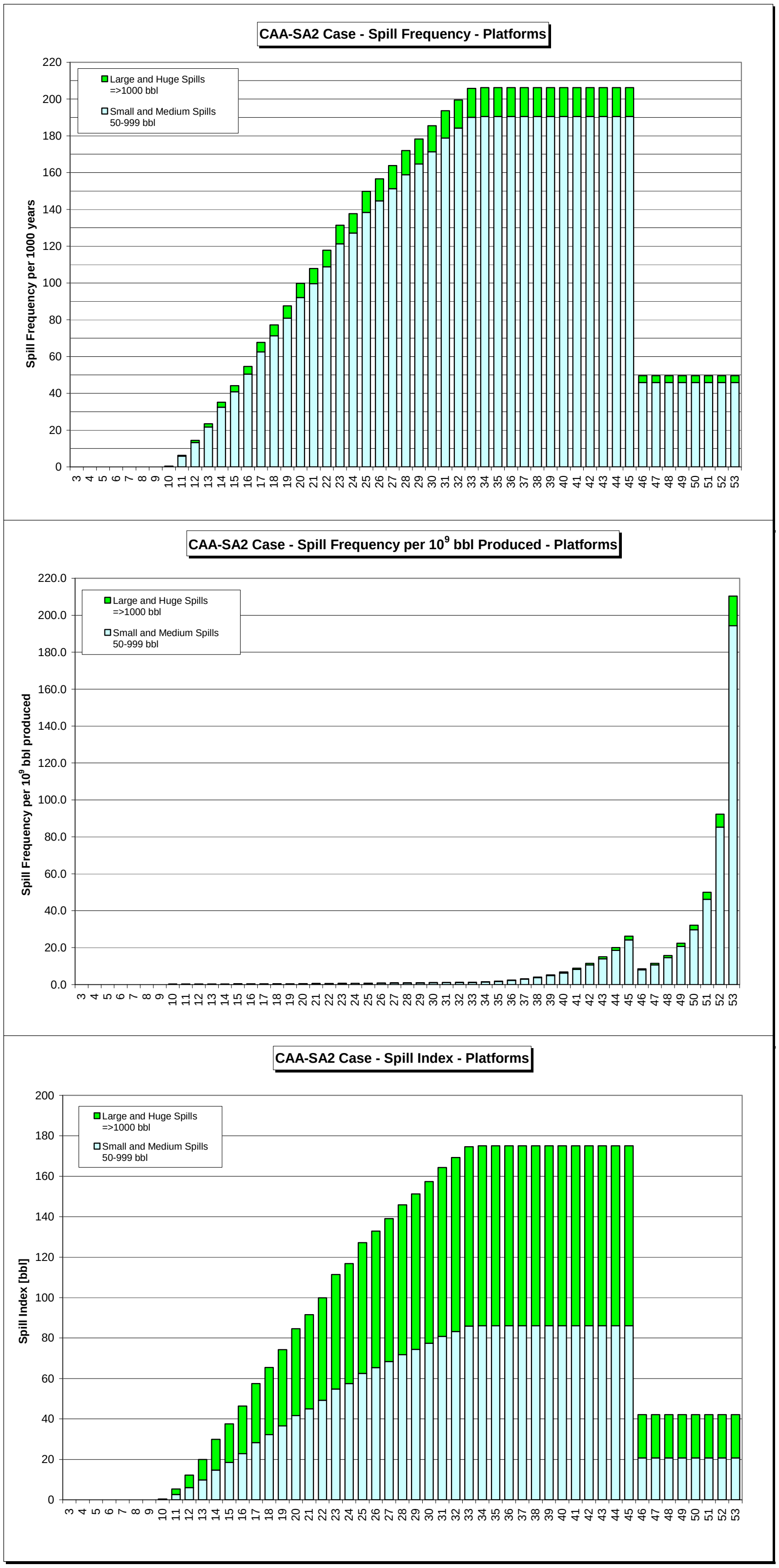


Figure 5.6
Project Spill Indicators – Platforms

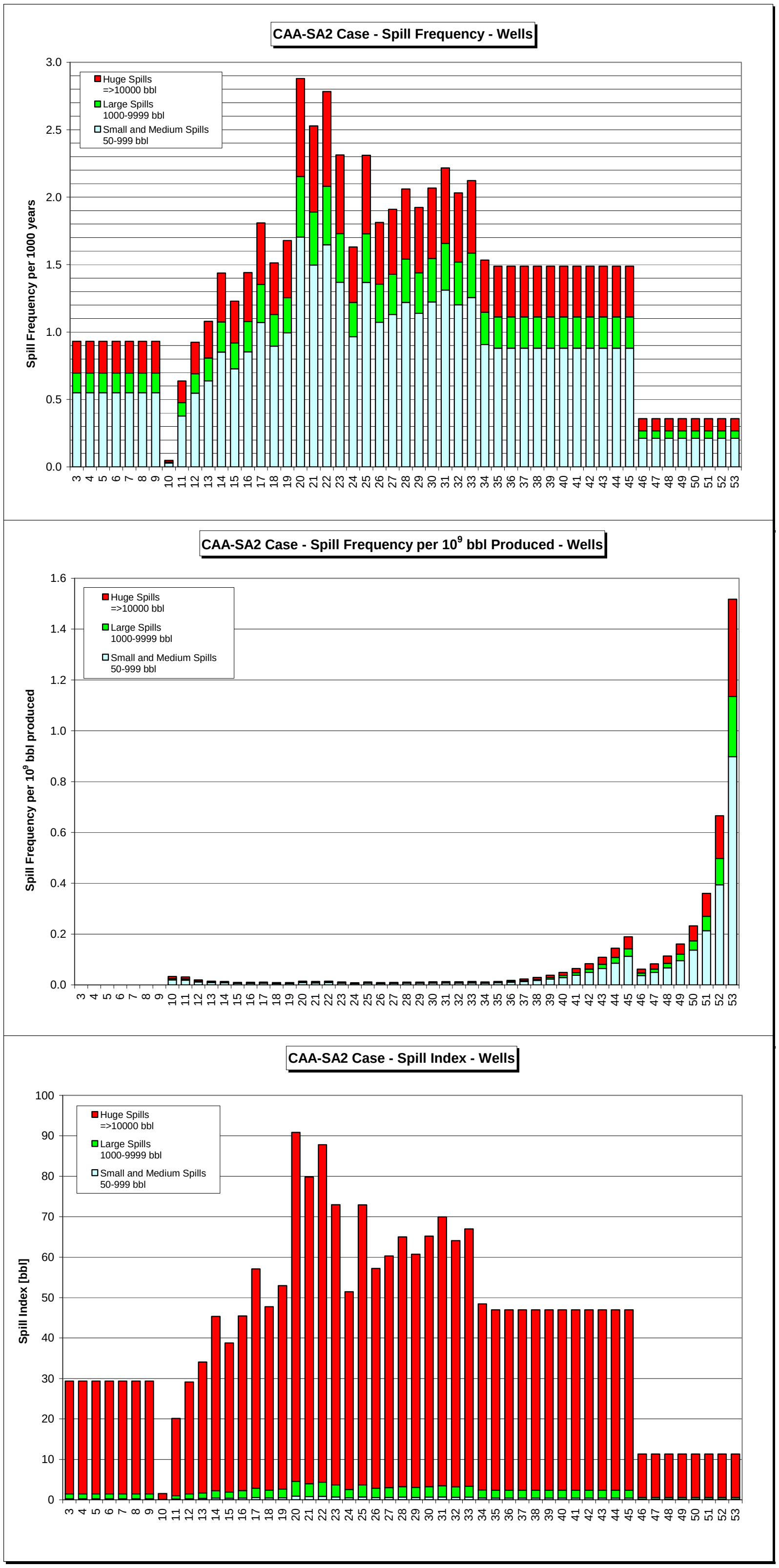


Figure 5.7
Project Spill Indicators – Wells

Finally, as part of the assessment of the Project scenario, a Monte Carlo analysis was carried out for each year, with the distributed inputs described earlier. The tabular results of the Monte Carlo simulation are summarized in Table 5.1 for the Project year 33, the highest spill index year (as shown in Figure 5.4). This table gives the statistical characteristics of the calculated indicators for each of three spill size ranges, as well as a tabular summary of their cumulative distribution curves for a representative production year (33). Figure 5.8 shows graphs of the calculated cumulative distribution functions. Basically, the vertical axis gives the probability in percent that the corresponding value on the horizontal axis will not be exceeded. Thus, for example, referring to the right-hand central graph, for substantial spills >= 1,000 bbl (large and huge), there is a 50% probability that a spill frequency will be no more than 0.15 per billion barrels produced in year 33. In other words, there is a 50% chance that large and huge spills will occur at a rate of 0.15 per billion bbl or less.

The frequency spill indicator variability can be estimated from the upper (95%) and lower (5%) bound values. For example, for large spill frequency (from Table 5.1), the lower bound (6.15) is 24% of the mean (24.92); the upper bound (49.34), 197% of the mean. The flattening or decrease in slope of the CDFs above 90% and below 10% can be attributed to the use of the triangular distribution with designated limits at corresponding (± 10%) levels.

In addition, since the Life of Field (LOF) averages were calculated, results from these are available for each scenario. Only representative examples are given. Table 5.2 shows the composition of the spill indicators for the Sale 1 Life of Field average. The composition both by spill size (on the left hand side of the table) and by facility contribution (on the right hand side of the table). The variability of the spill frequencies Life of Field averages is shown in the following figures: Figure 5.9 illustrates the variability of the spill frequency, while Figure 5.10 shows variability of frequency per billion barrels produced. Figure 5.11 shows the variability of the Spill Index.

5.3.2 Comparative Non-Arctic Indicator Assessment

To give an idea of the effect of the frequency variations introduced in Chapter 4, the Project scenario was also modeled utilizing unaltered historical frequencies. That is, no changes to incorporate the Arctic effects were introduced in the spill indicator calculations. Put yet another way, it was assumed that the facilities of the scenario would behave as if they were designed for and located in the Gulf of Mexico environment rather than in the Arctic environment, with the same facility quantities and production rates as their Arctic counterparts. Figures 5.12, 5.13, and 5.14 show the total values calculated for each of the three spill indicators. The dark histogram bar on the right side corresponds to the Arctic spill indicator, while, that on the left, corresponds to the computation based on historical frequencies only. Spill frequency in an absolute sense is considerably higher for the non-Arctic situation, roughly by 50%. The spills per 10^9 barrels produced for the Arctic development scenarios can also be expected to have a lower oil spill occurrence rate than similar development scenarios would have in the GOM.

Table 5.1
Project Year 33 – Monte Carlo Results

CAA-SA2 Year 33	Small and Medium Spills 50-999 bbl	Large Spills 1000-9999 bbl	Huge Spills =>10000 bbl	Substantial Spills =>1000 bbl	All Spills	Small and Medium Spills 50-999 bbl	Large Spills 1000-9999 bbl	Huge Spills =>10000 bbl	Substantial Spills =>1000 bbl	All Spills	Small and Medium Spills 50-999 bbl	Large Spills 1000-9999 bbl	Huge Spills =>10000 bbl	Substantial Spills =>1000 bbl	All Spills
	Frequency Spills per 10^3years					Frequency Spills per 10^9 bbl Produced					Spill Index (bbl)				
Mean =	129.835	18.410	8.163	26.573	156.408	1.555	0.220	0.098	0.318	1.873	56.664	98.205	121.600	219.805	276.469
Std Deviation =	81.74	9.94	3.93	11.51	82.45	0.98	0.12	0.05	0.14	0.99	53.43	70.52	50.49	92.48	106.74
Variance =	6681.2	98.8	15.5	132.5	6798.1	1.0	0.0	0.0	0.0	1.0	2855.2	4973.2	2548.9	8552.0	11394.2
Skewness =	0.81	0.63	0.50	0.51	0.79	0.81	0.63	0.50	0.51	0.79	1.91	1.40	0.73	0.90	0.82
Kurtosis =	3.33	3.03	2.94	3.05	3.33	3.33	3.03	2.94	3.05	3.33	7.81	5.44	3.40	4.12	3.85
Mode =	59.64	10.94	6.49	21.52	91.93	0.71	0.13	0.08	0.26	1.10	17.49	63.96	108.55	175.15	202.74
Minimum =	-18.016	-3.164	-0.928	-3.859	-2.238	-0.216	-0.038	-0.011	-0.046	-0.027	-20.863	-33.498	1.385	-17.583	-9.168
5% Perc =	24.361	4.799	2.431	9.792	48.140	0.292	0.057	0.029	0.117	0.577	5.072	17.681	52.539	94.323	129.741
10% Perc =	37.094	6.758	3.294	12.614	62.973	0.444	0.081	0.039	0.151	0.754	9.456	27.009	62.370	113.635	152.469
15% Perc =	47.254	8.281	4.005	14.661	73.266	0.566	0.099	0.048	0.176	0.877	12.984	34.082	70.795	128.724	169.888
20% Perc =	56.875	9.620	4.608	16.440	83.411	0.681	0.115	0.055	0.197	0.999	16.583	41.209	77.679	141.813	185.718
25% Perc =	65.932	10.843	5.201	18.011	92.734	0.790	0.130	0.062	0.216	1.111	20.084	47.930	83.942	153.306	199.218
30% Perc =	75.272	12.002	5.777	19.625	101.640	0.901	0.144	0.069	0.235	1.217	23.675	54.312	90.083	164.245	210.905
35% Perc =	84.356	13.173	6.252	21.094	111.136	1.010	0.158	0.075	0.253	1.331	27.391	60.459	96.018	174.370	223.928
40% Perc =	94.388	14.410	6.727	22.487	120.774	1.130	0.173	0.081	0.269	1.446	31.059	67.372	102.071	184.707	237.033
45% Perc =	103.902	15.659	7.251	23.888	130.948	1.244	0.188	0.087	0.286	1.568	35.338	73.777	108.066	194.829	248.878
50% Perc =	115.551	16.930	7.756	25.371	141.808	1.384	0.203	0.093	0.304	1.698	40.057	80.685	113.965	205.539	260.878
55% Perc =	126.680	18.270	8.305	26.898	153.267	1.517	0.219	0.099	0.322	1.836	44.653	88.237	120.460	217.127	274.758
60% Perc =	138.572	19.683	8.850	28.493	164.822	1.660	0.236	0.106	0.341	1.974	50.469	96.938	127.327	229.164	288.834
65% Perc =	151.403	21.226	9.444	30.105	178.106	1.813	0.254	0.113	0.361	2.133	57.346	106.581	134.367	241.859	303.237
70% Perc =	165.416	23.028	10.062	31.934	191.684	1.981	0.276	0.121	0.382	2.296	65.914	117.528	142.959	255.574	319.015
75% Perc =	179.305	24.714	10.695	34.005	206.843	2.147	0.296	0.128	0.407	2.477	75.515	129.742	152.388	271.550	337.724
80% Perc =	196.660	26.770	11.477	36.225	223.997	2.355	0.321	0.137	0.434	2.683	88.704	146.087	163.114	289.971	360.192
85% Perc =	218.245	29.364	12.383	38.845	245.307	2.614	0.352	0.148	0.465	2.938	105.416	166.918	175.390	313.738	385.156
90% Perc =	245.671	32.450	13.563	42.294	272.235	2.942	0.389	0.162	0.507	3.260	128.863	192.817	191.381	344.240	419.217
95% Perc =	285.652	36.802	15.263	47.423	312.742	3.421	0.441	0.183	0.568	3.746	165.569	239.227	216.051	391.773	475.914
Maximum =	483.468	63.194	23.397	77.961	502.567	5.790	0.757	0.280	0.934	6.019	396.812	571.076	345.762	730.599	821.236

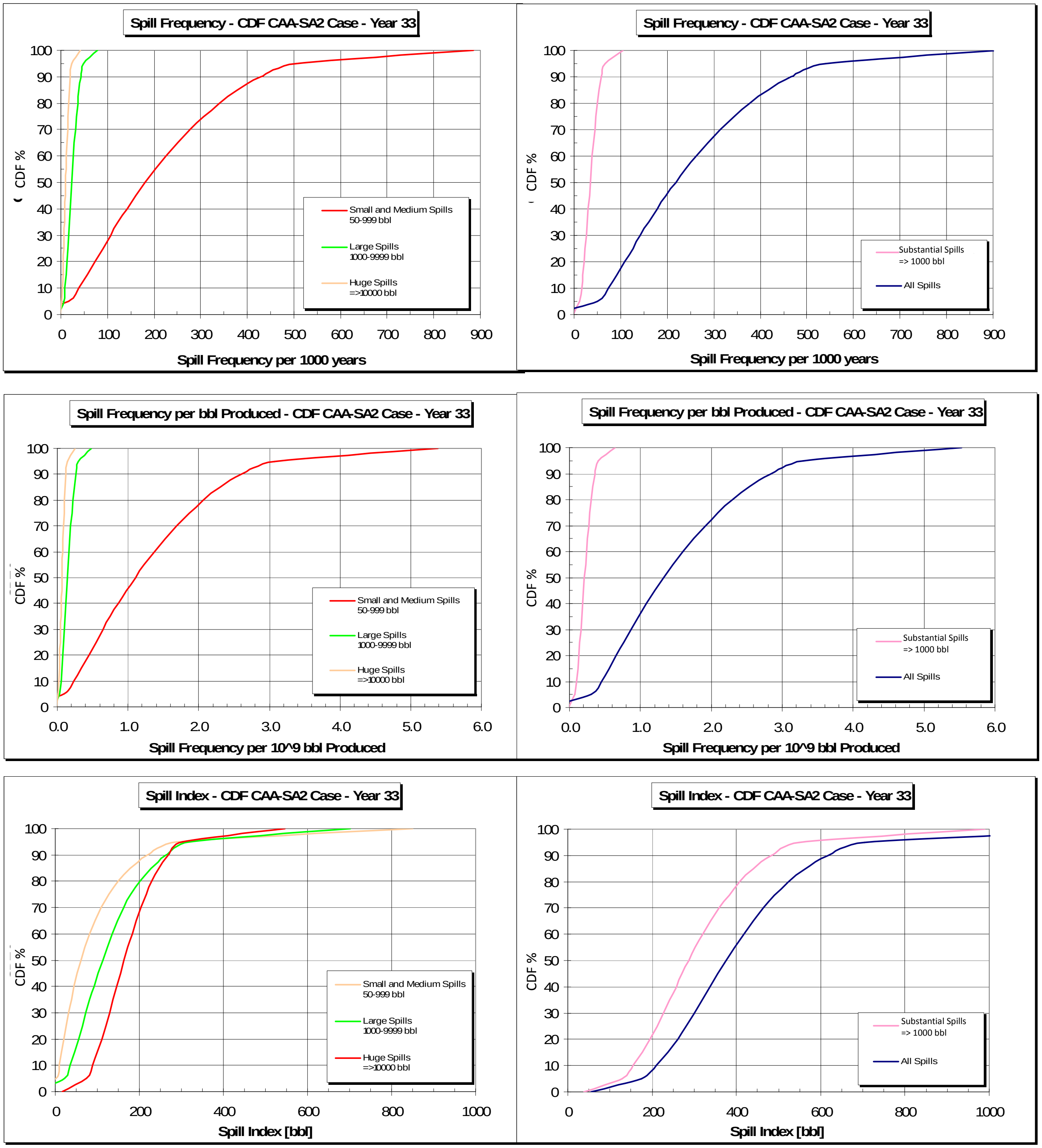


Figure 5.8
Project Spill Indicator Distributions – Year 33

Table 5.2
Composition of Project Spill Indicators –Life of Field Average

CAA-SA2 Pipeline	Small and Medium Spills 50-999 bbl	Large Spills 1000-9999 bbl	Huge Spills =>10000 bbl	Substantial Spills =>1000 bbl	All Spills	Small and Medium Spills 50-999 bbl	Large Spills 1000-9999 bbl	Huge Spills =>10000 bbl	Substantial Spills =>1000 bbl	All Spills	Small and Medium Spills 50-999 bbl	Large Spills 1000-9999 bbl	Huge Spills =>10000 bbl	Substantial Spills =>1000 bbl	All Spills
All years Average LOF	Frequency Spills per 10^3years					Frequency Spills per 10^9 bbl Produced					Spill Index [bbl]				
Mean =	130.129	18.379	8.156	26.534	156.663	1.558	0.220	0.098	0.318	1.876	56.780	97.525	121.463	218.988	275.769
Std Deviation =	82.50	9.85	3.95	11.30	83.37	0.99	0.12	0.05	0.14	1.00	53.59	69.48	50.69	90.38	104.37
Variance =	6806.791	97.095	15.581	127.606	6950.505	0.976	0.014	0.002	0.018	0.997	2871.712	4828.064	2569.797	8169.103	10893.780
Skewness =	0.81	0.61	0.53	0.50	0.79	0.81	0.61	0.53	0.50	0.79	1.88	1.38	0.74	0.82	0.78
Kurtosis =	3.32	2.95	3.09	2.96	3.34	3.32	2.95	3.09	2.96	3.34	7.67	5.60	3.43	3.78	3.77
Mode =	61.72	12.41	6.31	24.70	111.01	0.74	0.15	0.08	0.30	1.33	12.30	39.52	100.96	209.26	225.51
Minimum =	-31.042	-3.157	-0.622	-0.881	-1.709	-0.372	-0.038	-0.007	-0.011	-0.020	-33.347	-33.389	6.652	17.867	38.353
5% Perc =	23.119	4.668	2.429	10.181	47.756	0.277	0.056	0.029	0.122	0.572	4.646	17.901	52.233	95.479	132.476
10% Perc =	36.137	6.686	3.337	12.807	61.721	0.433	0.080	0.040	0.153	0.739	9.088	26.214	62.856	115.990	155.130
15% Perc =	47.398	8.251	4.020	14.819	72.818	0.568	0.099	0.048	0.177	0.872	12.599	33.602	70.089	129.674	171.498
20% Perc =	56.778	9.628	4.612	16.517	82.762	0.680	0.115	0.055	0.198	0.991	16.364	40.005	77.092	141.968	185.799
25% Perc =	66.098	10.858	5.202	18.033	92.128	0.792	0.130	0.062	0.216	1.103	19.827	46.783	83.556	152.740	199.330
30% Perc =	75.446	12.095	5.746	19.623	101.529	0.904	0.145	0.069	0.235	1.216	23.412	53.496	89.475	163.719	212.411
35% Perc =	84.611	13.252	6.265	21.039	111.742	1.013	0.159	0.075	0.252	1.338	27.383	59.936	95.606	174.181	224.541
40% Perc =	94.746	14.436	6.714	22.425	120.868	1.135	0.173	0.080	0.269	1.448	31.467	66.686	101.457	183.817	236.077
45% Perc =	104.845	15.681	7.227	23.913	131.272	1.256	0.188	0.087	0.286	1.572	35.950	73.659	107.819	194.646	248.549
50% Perc =	114.706	16.950	7.765	25.421	141.597	1.374	0.203	0.093	0.304	1.696	40.626	80.972	113.754	205.964	261.011
55% Perc =	125.950	18.304	8.306	26.879	151.891	1.508	0.219	0.099	0.322	1.819	45.931	88.768	120.550	217.057	274.174
60% Perc =	137.635	19.663	8.864	28.519	164.757	1.648	0.235	0.106	0.342	1.973	51.573	97.545	127.586	228.740	287.935
65% Perc =	150.897	21.122	9.423	30.164	177.900	1.807	0.253	0.113	0.361	2.131	58.069	107.861	135.308	241.470	302.890
70% Perc =	163.975	22.845	10.007	31.743	191.675	1.964	0.274	0.120	0.380	2.296	65.798	117.995	143.268	255.797	318.859
75% Perc =	179.840	24.695	10.650	33.691	207.546	2.154	0.296	0.128	0.403	2.486	76.116	130.878	151.613	271.188	337.018
80% Perc =	198.377	26.772	11.439	35.946	225.767	2.376	0.321	0.137	0.431	2.704	88.467	146.148	162.322	289.100	358.326
85% Perc =	220.880	29.254	12.350	38.635	247.691	2.645	0.350	0.148	0.463	2.966	106.262	164.601	175.207	311.489	384.011
90% Perc =	249.155	32.379	13.483	42.244	276.146	2.984	0.388	0.161	0.506	3.307	127.966	192.192	191.394	340.630	416.960
95% Perc =	286.476	36.842	15.331	46.827	314.428	3.431	0.441	0.184	0.561	3.766	166.176	235.793	216.157	389.134	468.481
Maximum =	495.052	56.904	26.155	71.363	532.942	5.929	0.682	0.313	0.855	6.383	423.675	569.237	352.249	635.414	829.221

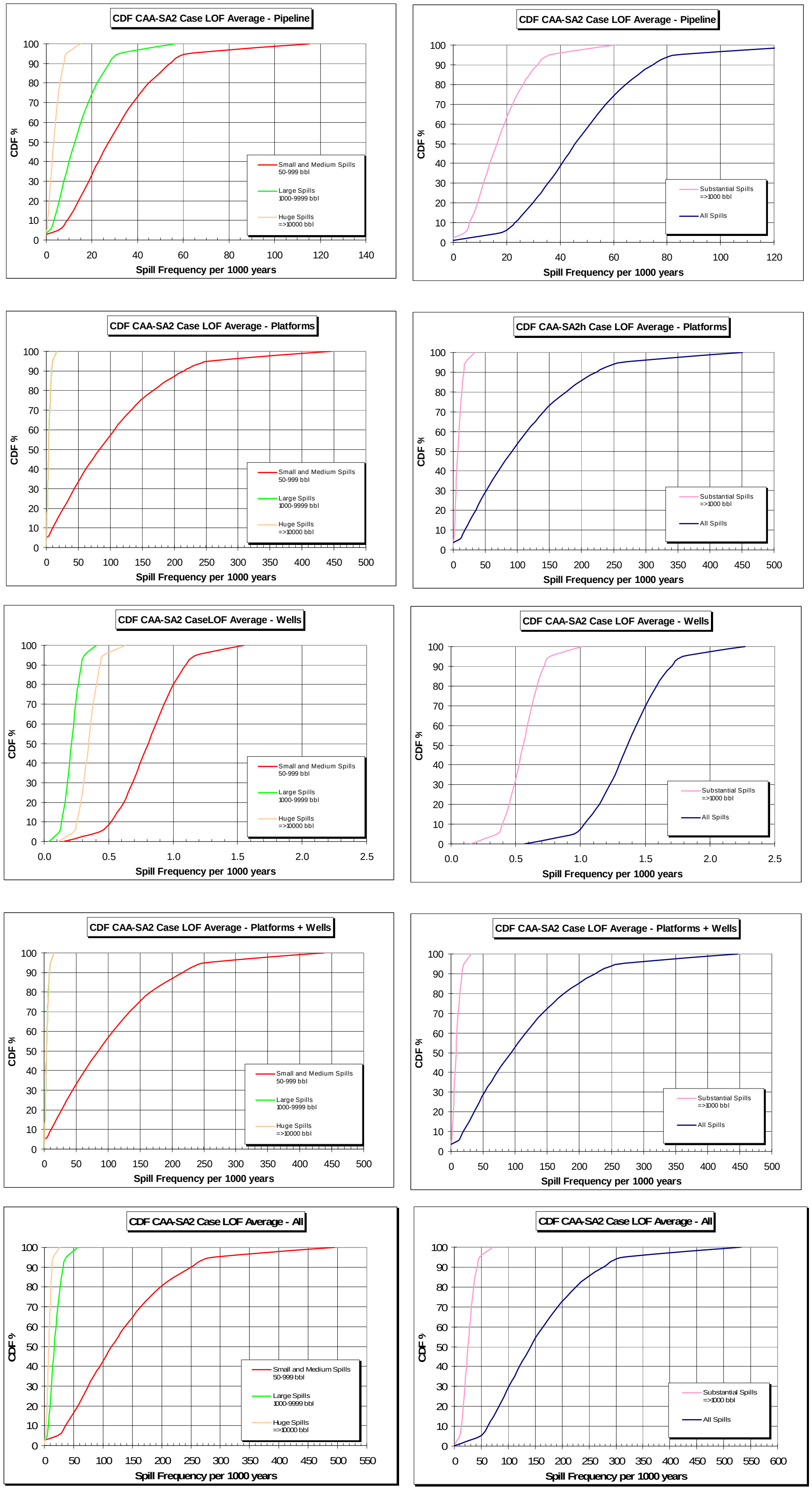


Figure 5.9: Project Life of Field Average Spill Frequency Variability

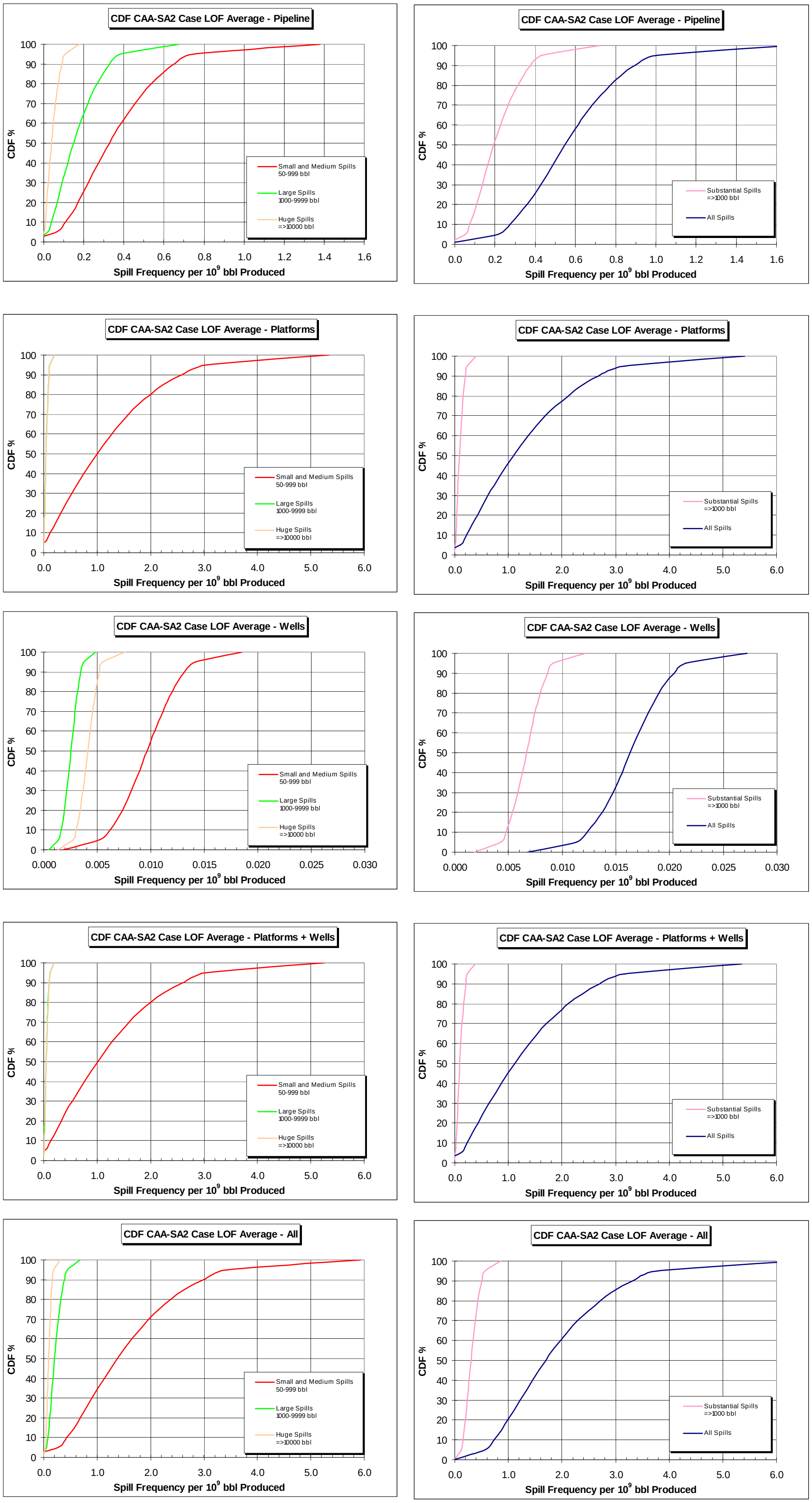


Figure 5.10: Project Life of Field Average Spills per 10^9 Barrel Produced Variability

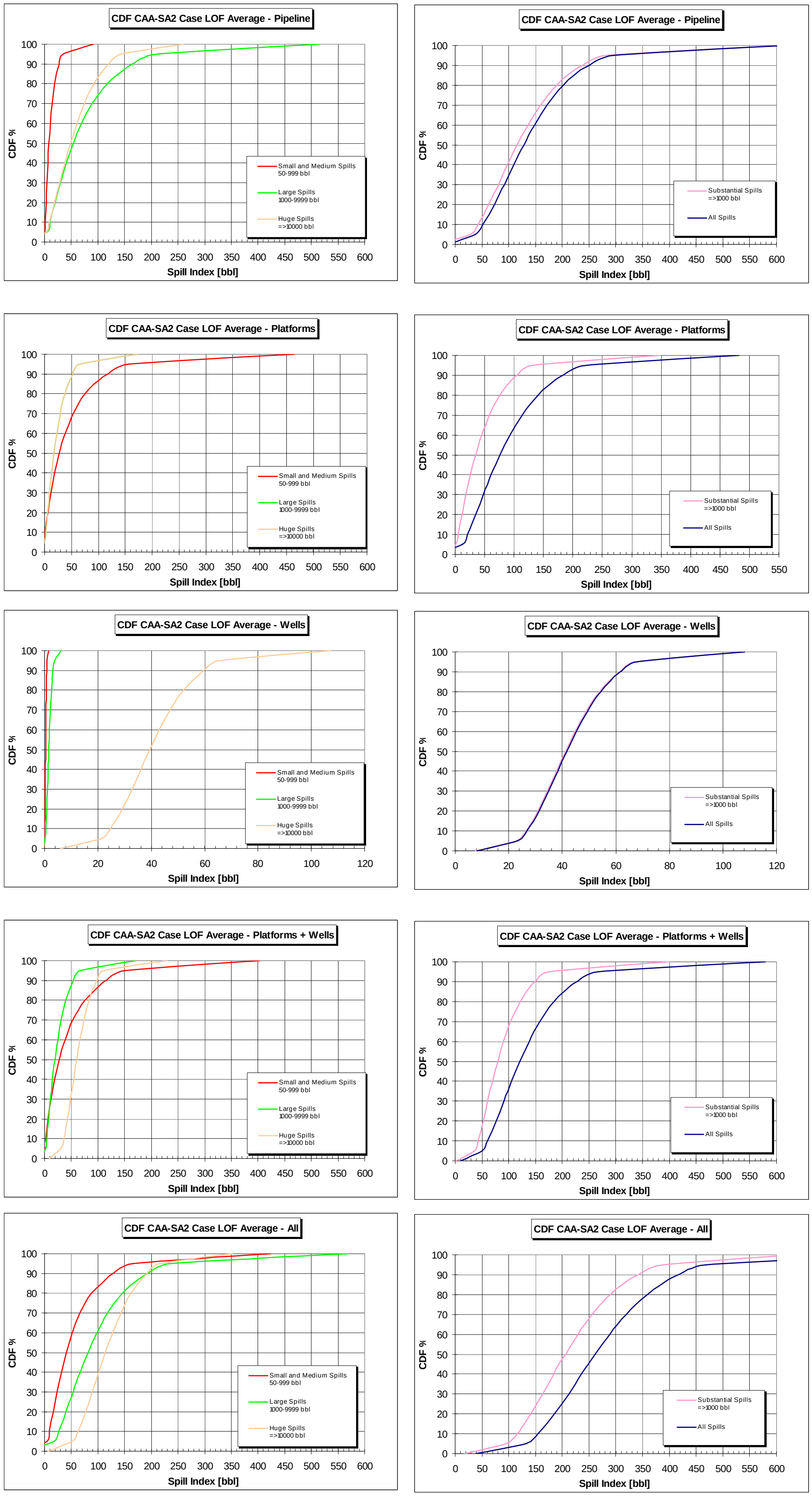


Figure 5.11: Project Life of Field Spill Index Variability

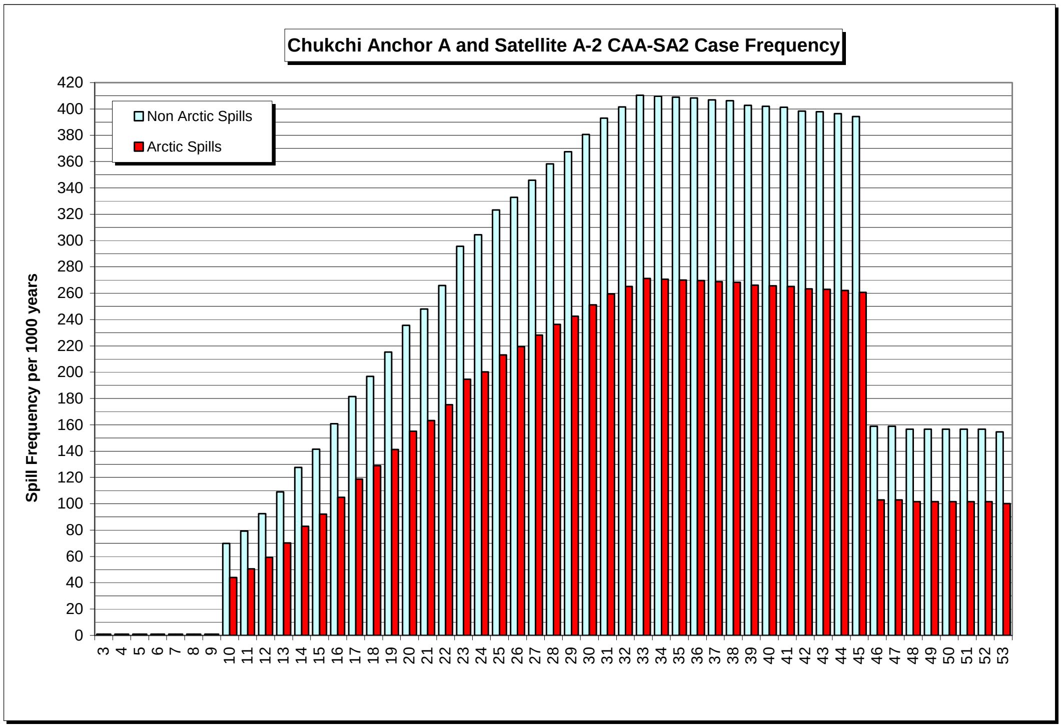


Figure 5.12
Project Spill Frequency – Arctic and Non-Arctic

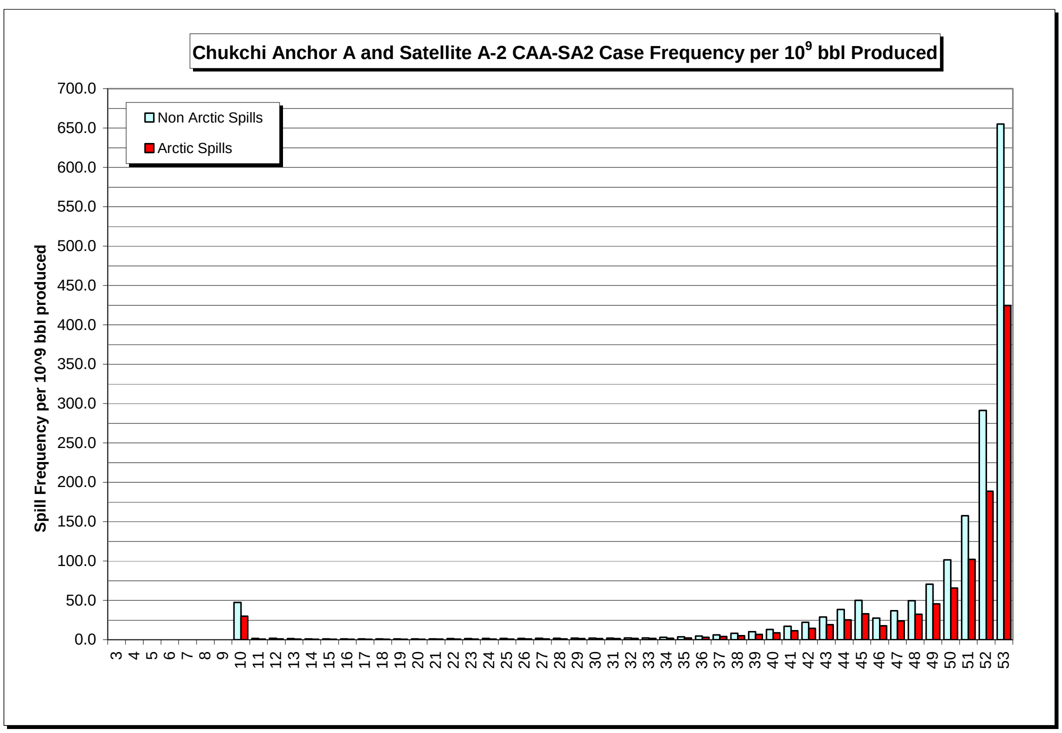


Figure 5.13
Project Spill Frequency per 10^9 Barrels Produced – Arctic and Non-Arctic

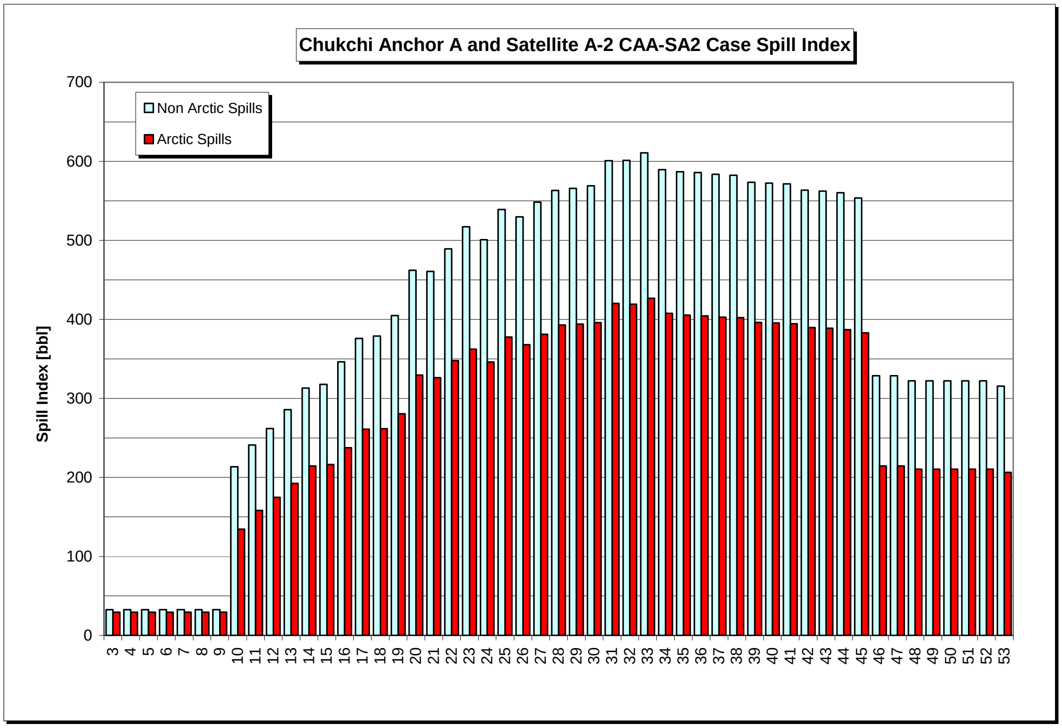
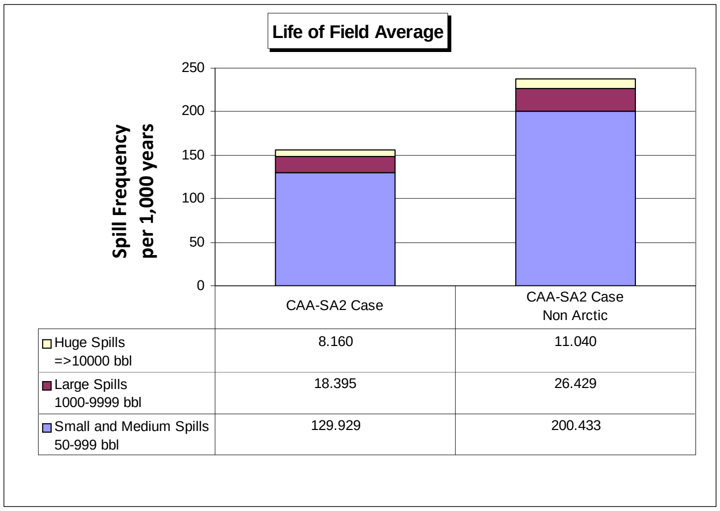


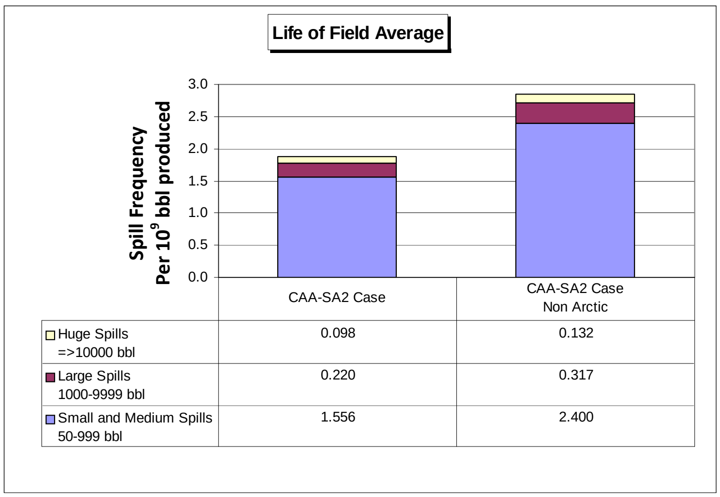
Figure 5.14
Project Spill Index – Arctic and Non-Arctic

Table 5.3
Summary of Spill Indicators for All Scenarios

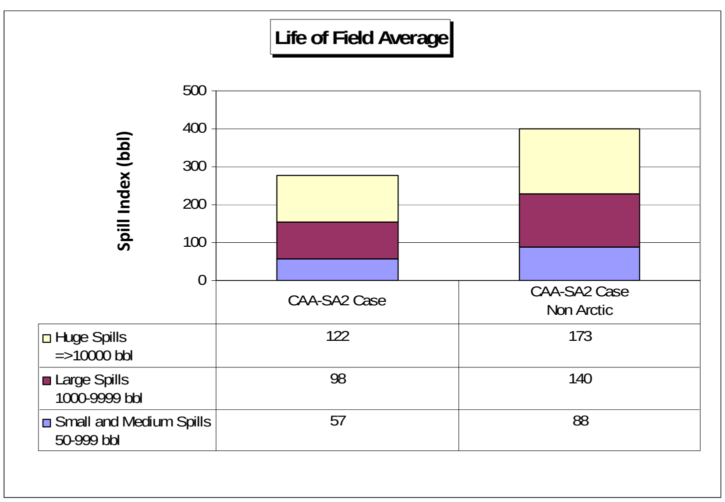
Spill Indicators LOF Average	CAA-SA2 Case			CAA-SA2 Case Non Arctic		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Small and Medium Spills 50-999 bbl	129.929	1.556	57	200.433	2.400	88
	83%	83%	21%	84%	84%	22%
Large Spills 1000-9999 bbl	18.395	0.220	98	26.429	0.317	140
	12%	12%	35%	11%	11%	35%
Huge Spills =>10000 bbl	8.160	0.098	122	11.040	0.132	173
	5%	5%	44%	5%	5%	43%
Substantial Spills =>1000 bbl	26.555	0.318	219	37.469	0.449	312
	17%	17%	79%	16%	16%	78%
All Spills	156.483	1.874	276	237.902	2.849	400
	100%	100%	100%	100%	100%	100%
Pipeline Spills	47.604	0.570	142	75.714	0.907	225
	30%	30%	51%	32%	32%	56%
Platform Spills	107.513	1.288	91	160.424	1.921	119
	69%	69%	33%	67%	67%	30%
Well Spills	1.366	0.016	43	1.764	0.021	56
	1%	1%	16%	1%	1%	14%
Platform and Well Spills	108.879	1.304	134	162.188	1.942	175
	70%	70%	49%	68%	68%	44%
All Spills	156.483	1.874	276	237.902	2.849	400
	100%	100%	100%	100%	100%	100%



	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Huge Spills =>10000 bbl	8.160	11.040
Large Spills 1000-9999 bbl	18.395	26.429
Small and Medium Spills 50-999 bbl	129.929	200.433

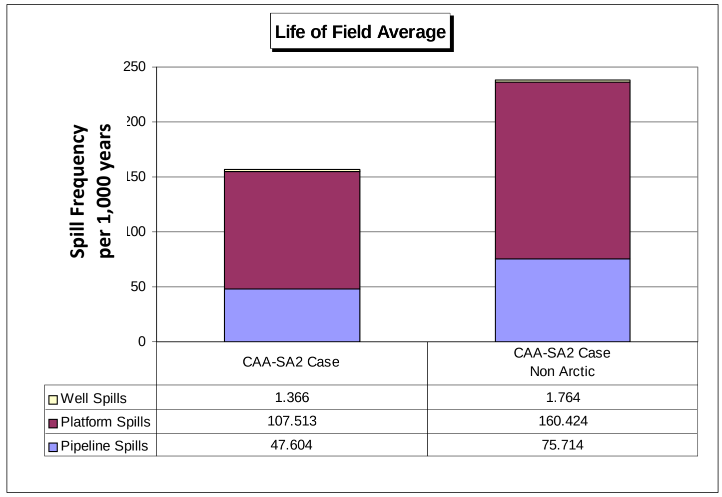


	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Huge Spills =>10000 bbl	0.098	0.132
Large Spills 1000-9999 bbl	0.220	0.317
Small and Medium Spills 50-999 bbl	1.556	2.400

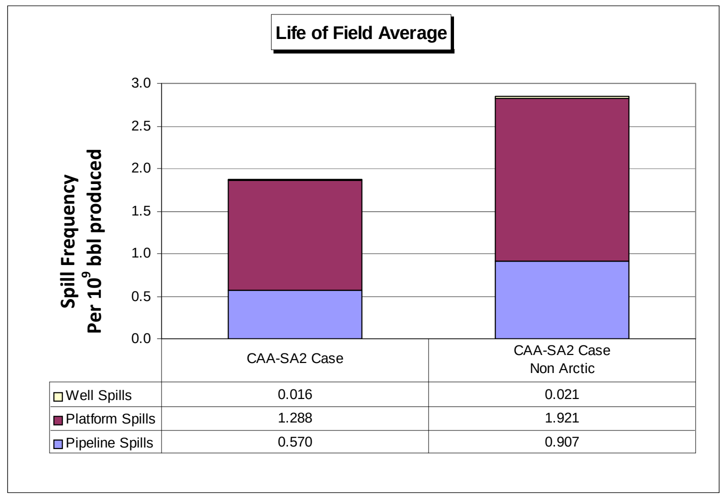


	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Huge Spills =>10000 bbl	122	173
Large Spills 1000-9999 bbl	98	140
Small and Medium Spills 50-999 bbl	57	88

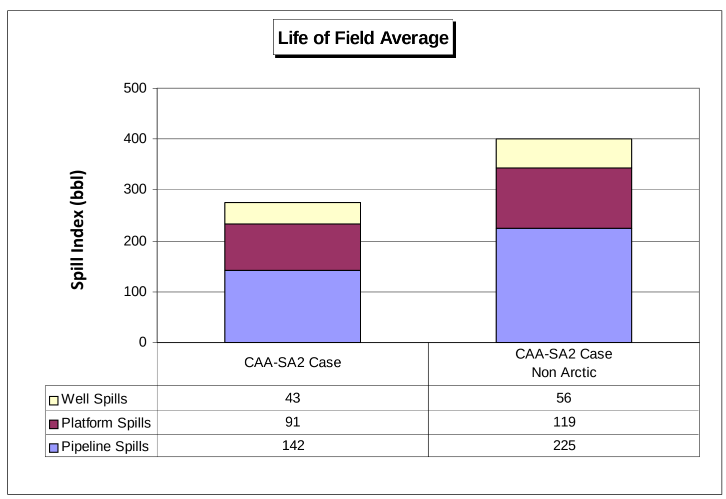
Figure 5.15
Project Life of Field Spill Indicators – By Spill Size



	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Well Spills	1.366	1.764
Platform Spills	107.513	160.424
Pipeline Spills	47.604	75.714



	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Well Spills	0.016	0.021
Platform Spills	1.288	1.921
Pipeline Spills	0.570	0.907



	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Well Spills	43	56
Platform Spills	91	119
Pipeline Spills	142	225

Figure 5.16
Project Life of Field Spill Indicators – By Source Composition

5.4 Summary of Representative Oil Spill Occurrence Indicator Results

How do spill indicators for the Project and for its non-Arctic counterpart vary by spill size and region? Table 5.3 and Figures 5.15 and 5.16 summarize the Life of Field average spill indicator values by spill size and source. The following can be observed from Table 5.3.

- Spill frequency per 10^3 years and per 10^9 barrels produced decrease with increasing spill size for both regions.
- The spill index increases with spill size for both regions.
- All non-Arctic region spill indicators are greater than their Arctic counterparts.

How do the spill indicators vary by facility type for representative scenarios? The contributions of spill indicators by facility have been summarized by representative scenario case, again, in Table 5.3 and also in Figure 5.16. Table 5.3 and Figure 5.16 give the component contributions, in absolute value and percent, for each of the main facility types; namely, pipelines (P/L), platforms, and wells. The following may be noted for the Arctic scenarios from Table 5.3:

- Platforms contribute the most (69%) to the two spill frequency indicators.
- Pipelines are second in relative contribution to spill frequencies (30%) and most in contribution to spill index (51%).
- Wells are the lowest contributors to both spill index (16%) and spill frequencies (1%).
- It can be concluded that platforms are likely to have the most, but smaller spills, while wells will have the least number but largest. Pipelines will be in between, with more spills than wells.

Figures 5.17 and 5.18 show relative contributions by facility and spill size to the maximum spill index year 33 and Life of Field average spill indicators, respectively. Although Life of Field average absolute values are considerably smaller than the maximum spill index year values, the proportional contributions by spill facility source and spill size are similar. In Figures 5.17 and 5.18, "TOTAL" designates the sum of the spill indicators for all spill sizes and facility types.

Figures 5.9, 5.10, and 5.11, earlier, showed the Cumulative Distribution Functions (CDF) the Project Life of Field average spill indicators. Generally, the following can be observed from the figures:

- The variance of the frequency spill indicators (Figures 5.9 and 5.10) decreases as spill size increases for pipelines and platforms. For example, in the top right-hand graph of Figure 5.9, the substantial spills plot has a much steeper (and hence less variable) slope than that of all spills. Similarly, in the top left-hand graph, small and medium spills illustrate the largest variability; huge spills show the least variability for pipelines.
- The opposite occurs for wells, where large spills show greater variance than small ones.

- The variability of the spill index (Figure 5.11) shows variance trends opposite to those of the frequency spill indicators for pipelines and platforms.

The Cumulative Distribution Functions contain extensive information on the statistical properties of the spill indicators. For example, from Figure 5.9, it can be seen, for all substantial spills (bottom right graph), that the Life of Field average mean (50%) value of 25 (spills per 1,000 years) ranges between approximately 50 and 10 at the upper and lower 95% confidence intervals, respectively. A similar percentage variation is shown for the Life of Field average spill frequency per 10^9 barrels produced in Figure 5.10. The spill index variability shown in Figure 5.11 is proportionally higher. For example, in Figure 5.11 (bottom right graph), the mean value of the substantial spills index of 200 barrels ranges from approximately 100 to 450 barrels.

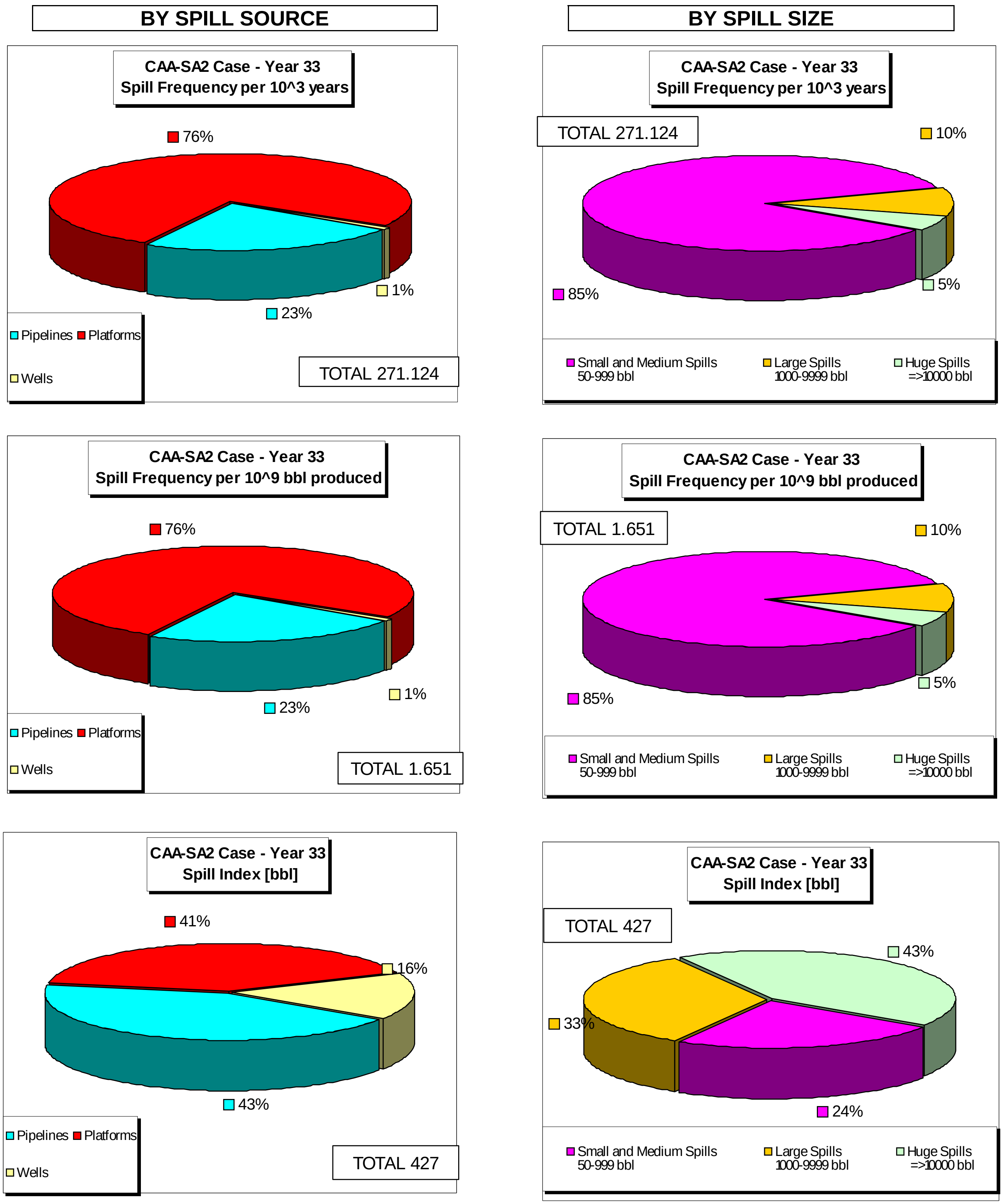


Figure 5.17
Project – Year 33 – Spill Indicator Composition by Source and Spill Size

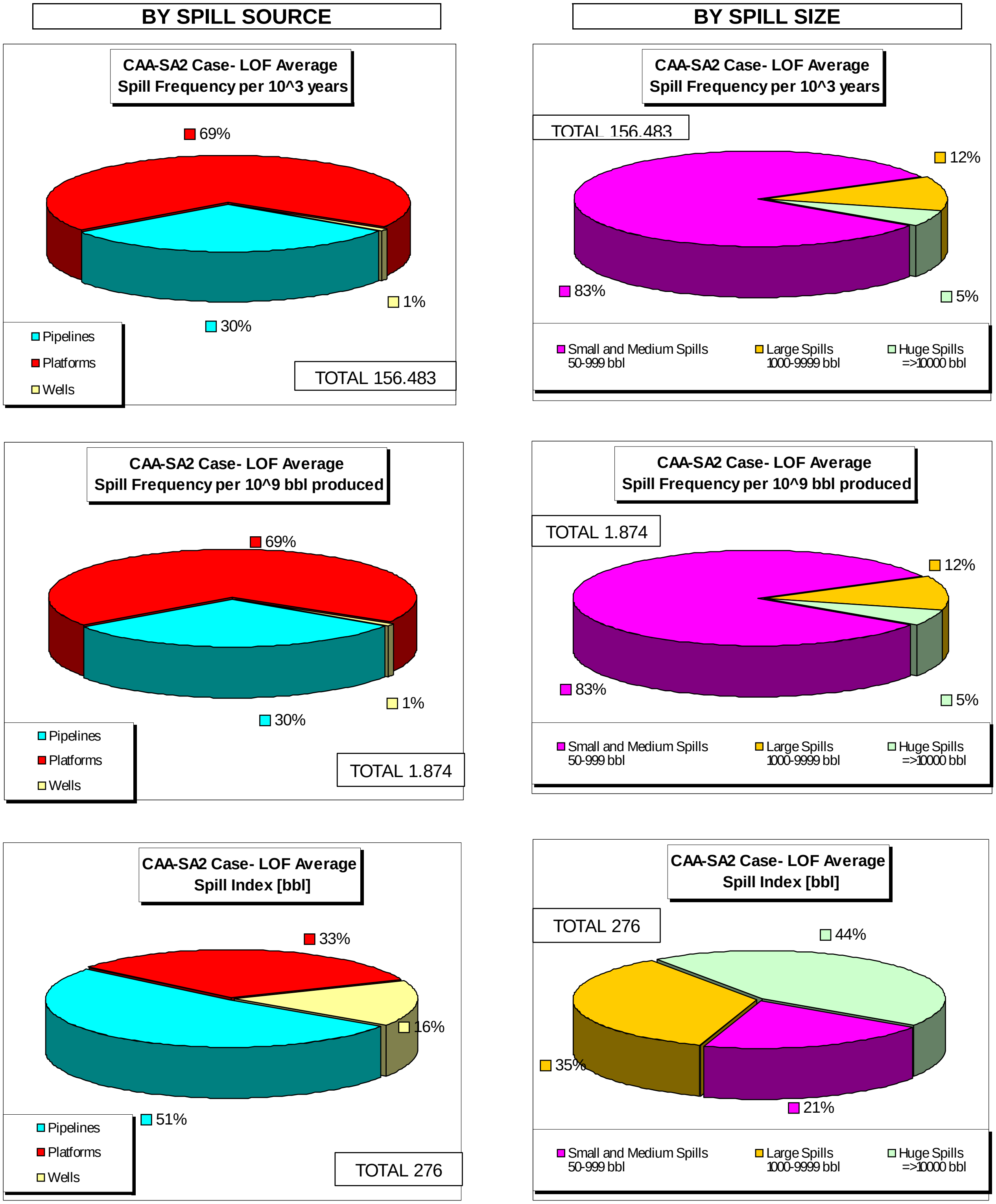


Figure 5.18
Project – Life of Field Average Spill Indicator Composition by Source and Spill Size

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

6.1.1 General Conclusions

Oil spill occurrence indicators were quantified for a hypothetical future offshore development scenario (the Project) in the Chukchi Sea Sale 193 Leased Area. The quantification included the consideration of the variability of historical and future scenario data, as well as that of Arctic effects in predicting oil spill occurrence indicators. Consideration of the variability of all input data yields both higher variability and a higher expected value of the spill occurrence indicators. The three types of spill occurrence indicators were: annual oil spill frequency, annual oil spill frequency per billion barrels produced, and annual spill index – additionally, the life of field averages for each of these three oil spill indicators were assessed.

6.1.2 Oil Spill Occurrence Indicators by Spill Size and Source

How do spill indicators for the Project scenario and for its non-Arctic counterpart vary by spill size and region? Table 6.1 and Figures 6.1 and 6.2 summarize the Life of Field average spill indicator values by spill size and source. The following can be observed from Table 6.1:

- Spill frequency per 10^3 years and per 10^9 barrels produced decreases with increasing spill size for all Arctic and non-Arctic scenarios.
- The spill index increases with spill size for all Arctic and non-Arctic scenarios.
- All non-Arctic scenario spill indicators are greater than their Arctic counterparts.

How do the spill indicators vary by facility type for representative scenarios? The contributions of spill indicators by facility have been summarized by representative scenario years, again, in Tables 6.1 and 6.2 and also in Figure 6.2. Figure 6.2 gives the component contributions, in absolute value and percent, for each of the main facility types; namely, pipelines (P/L), platforms, and wells. Figure 6.3 shows the distributions for Year 33. The following may be noted from Tables 6.1 and 6.2:

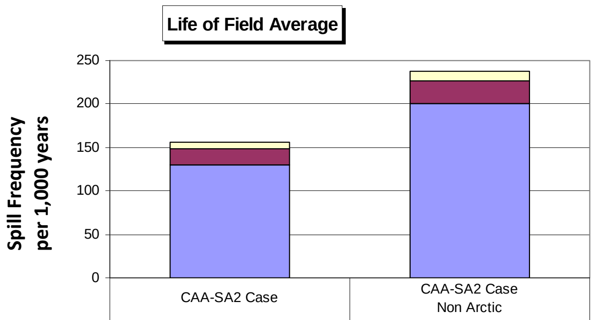
- Platforms contribute the most (69%) to the two Arctic spill frequency indicators.
- Pipelines are next in relative contribution to spill frequencies (30%) and most in contribution to spill index (51%).
- Wells are the lowest contributors to spill index (16%) and spill frequency (1%). Among wells, production wells are the highest contributor to all 3 well spill indicators (Table 6.2).
- It can be concluded that platforms are likely to have the most, but smaller spills, while wells will have the least number but larger spills. Pipelines will be in between, with more spills than wells.

Table 6.1
Summary of Life of Project Field Average Spill Indicators by Spill Source and Size

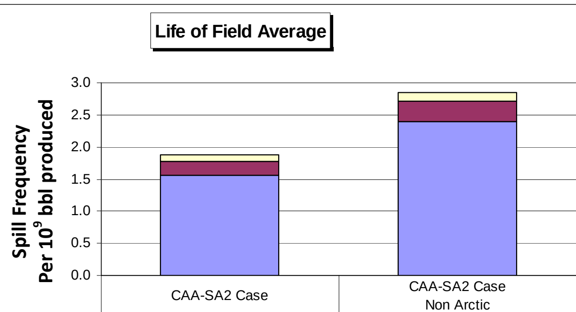
Spill Indicators LOF Average	CAA-SA2 Case			CAA-SA2 Case Non Arctic		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Small and Medium Spills 50-999 bbl	129.929	1.556	57	200.433	2.400	88
	83%	83%	21%	84%	84%	22%
Large Spills 1000-9999 bbl	18.395	0.220	98	26.429	0.317	140
	12%	12%	35%	11%	11%	35%
Huge Spills =>10000 bbl	8.160	0.098	122	11.040	0.132	173
	5%	5%	44%	5%	5%	43%
Substantial Spills =>1000 bbl	26.555	0.318	219	37.469	0.449	312
	17%	17%	79%	16%	16%	78%
All Spills	156.483	1.874	276	237.902	2.849	400
	100%	100%	100%	100%	100%	100%
Pipeline Spills	47.604	0.570	142	75.714	0.907	225
	30%	30%	51%	32%	32%	56%
Platform Spills	107.513	1.288	91	160.424	1.921	119
	69%	69%	33%	67%	67%	30%
Well Spills	1.366	0.016	43	1.764	0.021	56
	1%	1%	16%	1%	1%	14%
Platform and Well Spills	108.879	1.304	134	162.188	1.942	175
	70%	70%	49%	68%	68%	44%
All Spills	156.483	1.874	276	237.902	2.849	400
	100%	100%	100%	100%	100%	100%

Table 6.2
Summary of Life of Project Spill Indicators for Substantial Spills by Facility and Well Type

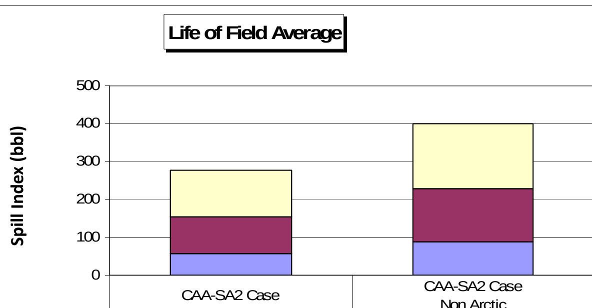
Spill Source LOF Average Substantial Spills => 1000 bbl	CAA-SA2 Case		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Pipeline	17.764	0.213	130
	67%	67%	59%
Platforms	8.233	0.099	46
	31%	31%	21%
Wells	0.558	0.007	43
	2%	2%	19%
Platforms and Wells	8.790	0.105	89
	33%	33%	41%
All	26.555	0.318	219
	100%	100%	100%
Production Wells	0.317	0.004	24
	57%	57%	57%
Exploration Wells	0.074	0.001	6
	13%	13%	13%
Development Wells	0.166	0.002	13
	30%	30%	30%
All Wells	0.558	0.007	43
	100%	100%	100%



	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Huge Spills =>10000 bbl	8.160	11.040
Large Spills 1000-9999 bbl	18.395	26.429
Small and Medium Spills 50-999 bbl	129.929	200.433

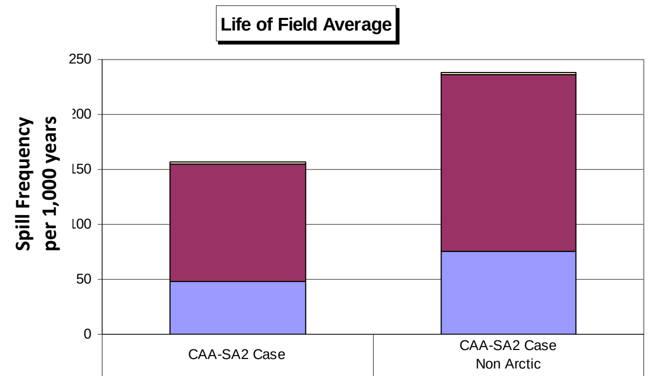


	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Huge Spills =>10000 bbl	0.098	0.132
Large Spills 1000-9999 bbl	0.220	0.317
Small and Medium Spills 50-999 bbl	1.556	2.400

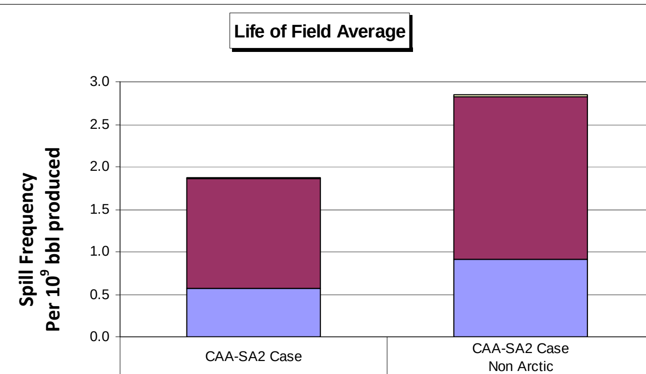


	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Huge Spills =>10000 bbl	122	173
Large Spills 1000-9999 bbl	98	140
Small and Medium Spills 50-999 bbl	57	88

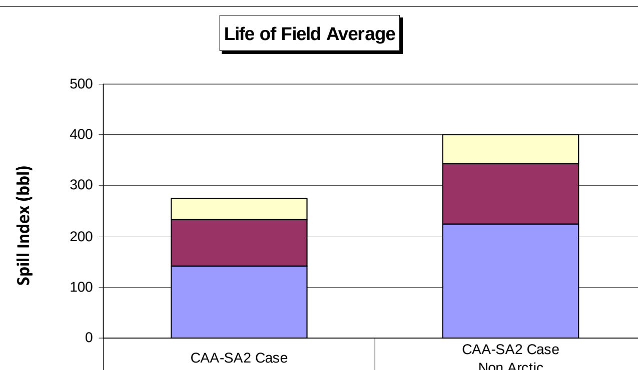
Figure 6.1
Project Life of Field Spill Indicators – By Spill Size



	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Well Spills	1.366	1.764
Platform Spills	107.513	160.424
Pipeline Spills	47.604	75.714



	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Well Spills	0.016	0.021
Platform Spills	1.288	1.921
Pipeline Spills	0.570	0.907



	CAA-SA2 Case	CAA-SA2 Case Non Arctic
Well Spills	43	56
Platform Spills	91	119
Pipeline Spills	142	225

Figure 6.2
Project Life of Field Spill Indicators – By Source Composition

Figures 6.3 and 6.4 show relative contributions by facility and spill size to the maximum spill index year 33 and Life of Field average spill indicators, respectively. Although Life of Field average absolute values are considerably smaller than the maximum production year values, the proportional contributions by spill facility source and spill size are similar. In Figures 6.3 and 6.4, “TOTAL” designates the sum of the spill indicators for all spill sizes and facility types.

6.1.3 The Variance of Oil Spill Occurrence Indicators

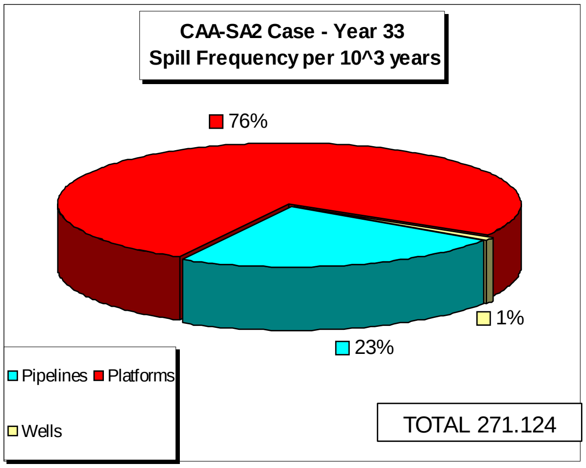
Figures 6.5, 6.6, and 6.7 show the Cumulative Distribution Functions (CDF) for the Project Life of Field average spill indicators. Generally, the following can be observed from the figures:

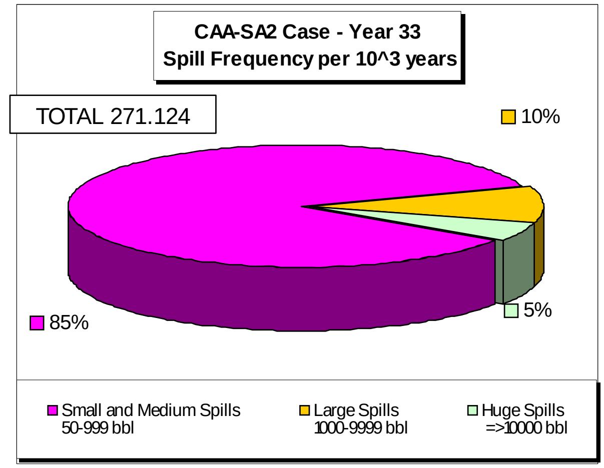
- The variance of the frequency spill indicators (Figures 6.5 and 6.6) decreases as spill size increases for pipelines and platforms. For example, in the top right-hand graph of Figure 6.5, the substantial spills plot has a much steeper (and hence less variable) slope than that of all spills. Similarly, in the top left-hand graph, small and medium spills illustrate the largest variability; huge spills show the least variability for these facilities.
- The opposite occurs for wells, where large spills show greater variance than small ones, shown in the same manner.
- The variability of the spill index (Figure 6.7) shows variance trends opposite to those of the frequency spill indicators for pipelines and platforms.

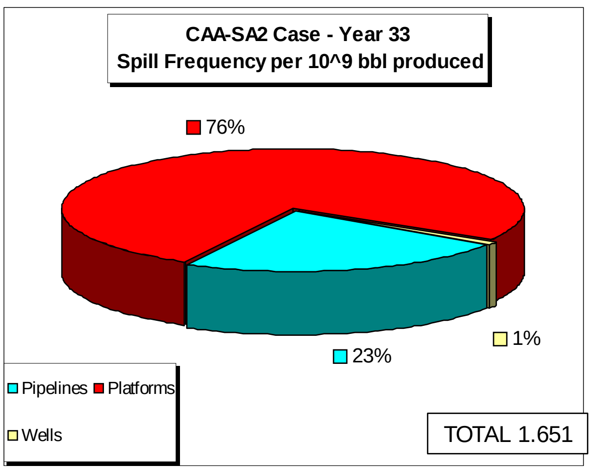
The Cumulative Distribution Functions contain extensive information on the statistical properties of the spill indicators. For example, from Figure 6.5, it can be seen, for all substantial spills, that the Life of Field average mean (50%) value of 25 (spills per 1,000 years) ranges between about 50 and 10 at the upper and lower 95% confidence intervals. A similar percentage variation is shown for the Life of Field average spill frequency per 10^9 barrels produced in Figure 6.6. The spill index variability shown in Figure 6.7 is proportionally higher. For example, in Figure 6.7, the mean value of the substantial spills spill index of 200 barrels ranges from 100 to 450 barrels.

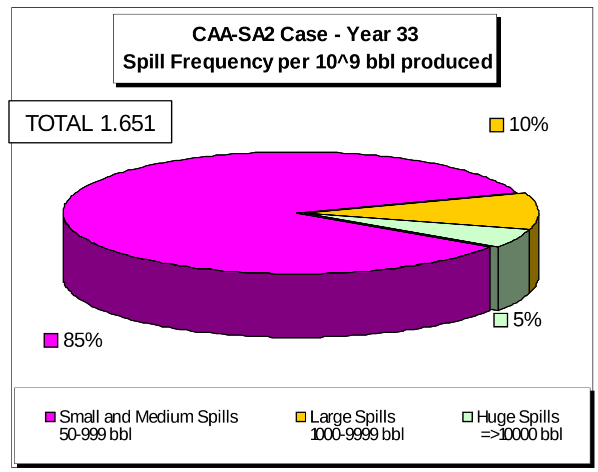
BY SPILL SOURCE

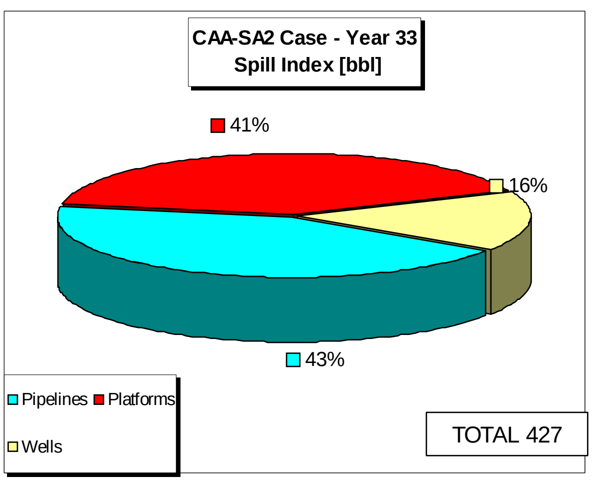
BY SPILL SIZE











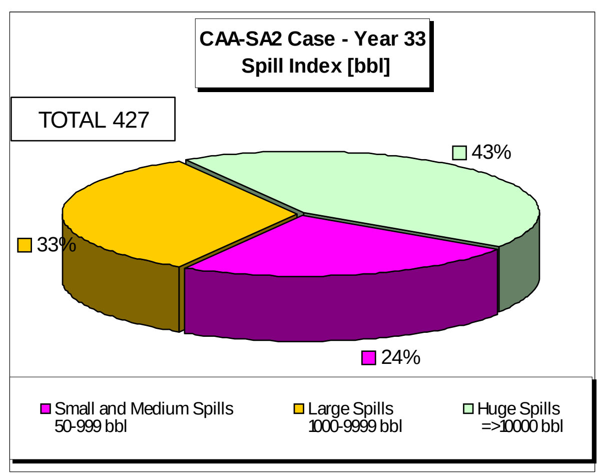


Figure 6.3
Project – Year 33 – Spill Indicator Composition by Source and Spill Size

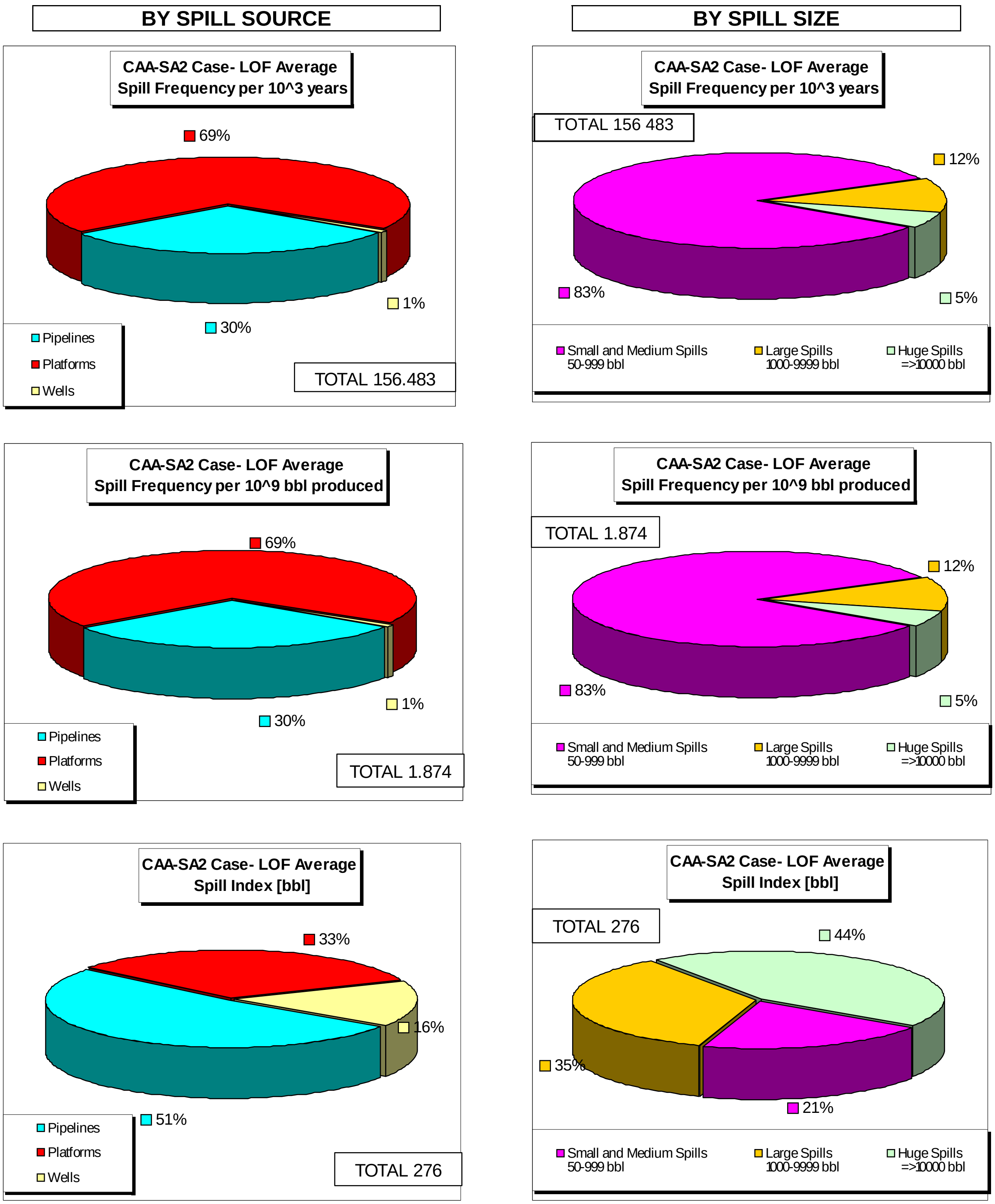


Figure 6.4
Project – Life of Field Average Spill Indicator Composition by Source and Spill Size

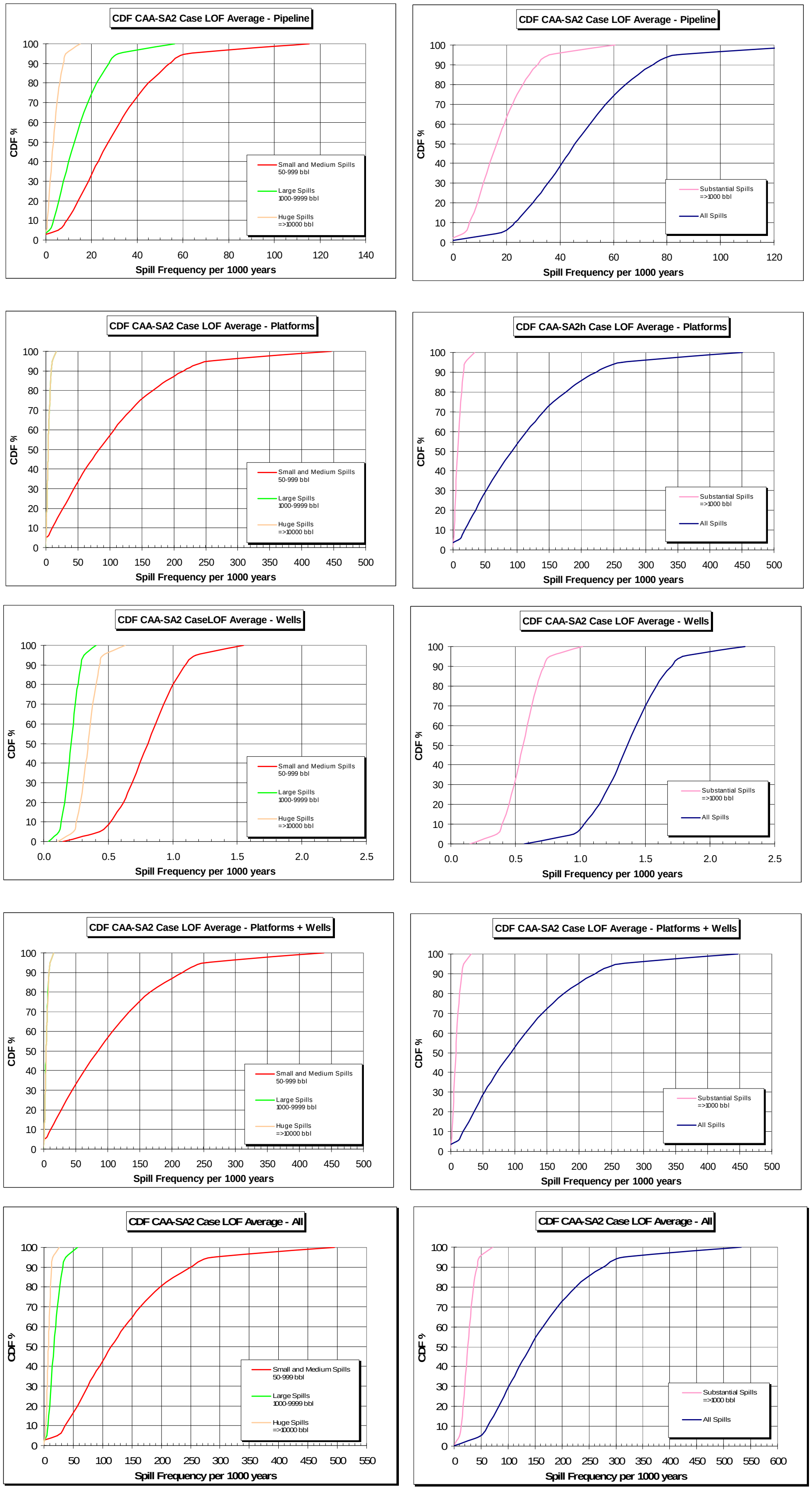


Figure 6.5: Project Life of Field Average Spill Frequency Variability

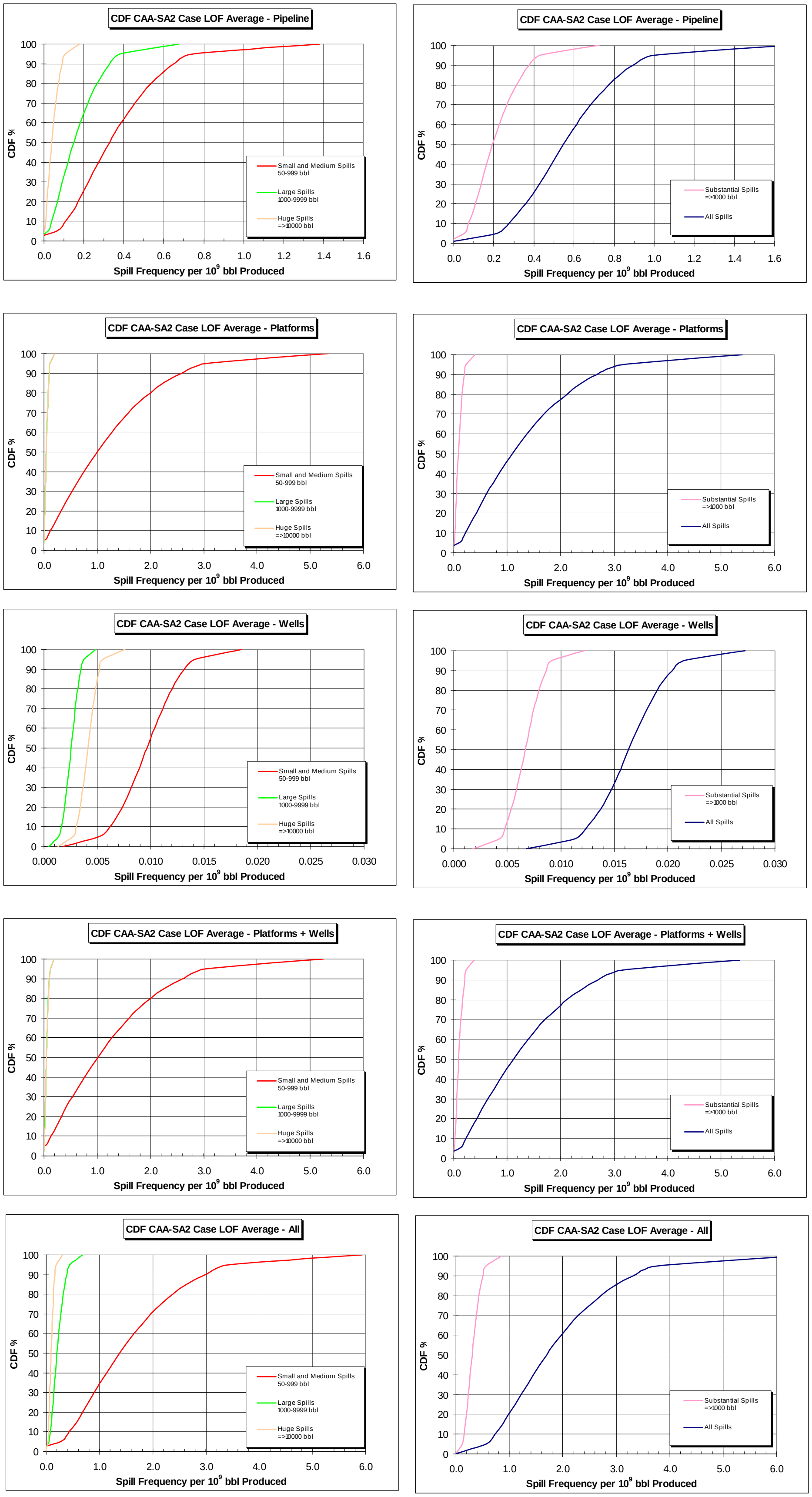


Figure 6.6: Project Life of Field Average Spills per 10^9 Barrels Produced Variability

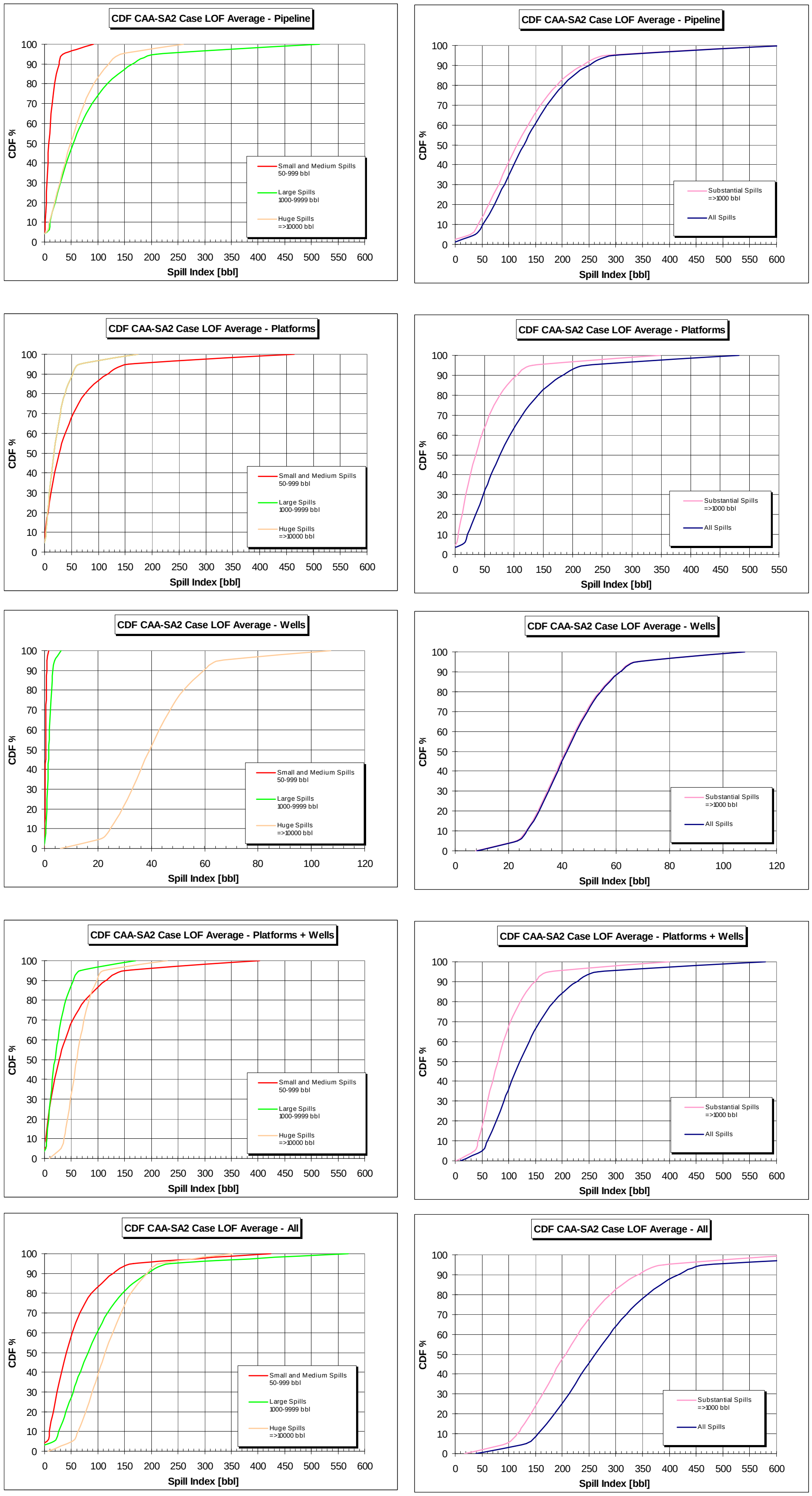


Figure 6.7: Project Life of Field Spill Index Variability

6.2 Conclusions on the Methodology and its Applicability

An analytical tool for the prediction of oil spill occurrence indicators for systems without history, such as future offshore oil production developments in the Chukchi Sea, has been developed based on the utilization of fault tree methodology. Although the results generated are voluminous, they are essentially transparent, simple, and easy to understand. The analytical tool developed is also quite transparent, very efficient in terms of computer time and input-output capability. In addition, the predictive model is setup so that input variables can be entered as distributions.

A wealth of information that can be utilized for the optimal planning and regulation of future developments is generated by the analytical tool. Key aspects of the analytical tool capability may be summarized as follows:

- Ability to generate expected and mean values as well as their variability in rigorous numerical statistical format.
- Use of verifiable input data based on BSEE or other historical spill data and statistics.
- Ability to independently vary the impacts of different causes on the spill occurrences as well as add new causes such as some of those that may be expected for the Arctic or other new environments.
- Ability to generate spill occurrence indicator characteristics such as annual variations, facility contributions, spill size distributions, and life of field (Life of Field) averages.
- Ability to generate comparative spill occurrence indicators such as those of comparable scenarios in more temperate regions. The model developed provides a basis for estimating each Arctic effect's importance through sensitivity analysis as well as propagation of uncertainties.
- Capability to quantify uncertainties rigorously, together with their measures of variability.

6.3 Suggested Improvement to the Methodology and Results

During the work, a number of areas were identified where future improvements could be made, including: the input data, the scenarios, the application of the fault tree methodology, and finally the oil spill occurrence indicators themselves have been identified. These suggestions are summarized in the following paragraphs.

Two categories of input data were used; namely the historical spill data and the Arctic effect data. Although a verifiable and optimal historical spill data set has been used, the following shortcomings may be noted:

- Gulf of Mexico and Pacific (OCS) historical databases were compiled by BSEE for pipelines and facilities, and were used as a starting point for the fault tree analysis. Although these data are adequate, a broader population base would be expected to give more robust statistics. For well LOWC data, both the BSEE and the proprietary SINTEF data were used.

- The Arctic effects include modifications in causes associated with the historical data set as well as additions of spill causes unique to the Arctic environment. Quantification of existing causes for Arctic effects was done in a relative cursory way restricted to engineering judgment.

- Upheaval buckling effect assessments were included on the basis of professional judgment used in previous studies; no engineering analysis was carried out for the assessment of frequencies for Chukchi locations to be expected for these effects.

The Scenario was developed by the BOEM, Resource & Economic Analysis Section for the Sale 193 Leased Area Second Supplemental Environmental Impact Statement. They appear reasonable, and were incorporated in the form provided. For purposes of this analysis platform/well abandonment was only considered at the end of the Anchor and Satellite life leading to conservative estimates of spill frequency. The only consideration appears to be that the facility abandonment rate is considerably lower than the rate of decline in production, resulting in very high estimates of spill frequency per 10^9 barrels produced during the pre-abandonment years.

The following comments can be made on constraints associated with the indicators that have been generated:

- The indicators are a function of the input and scenario data noted above. For example, yearly abandonment rates for platforms rather than by end of Anchor and Satellite life would lower the spill frequency per 10^9 barrels produced during the pre-abandonment years.

- The model generating the indicators is fundamentally a linear model which ignores the effects of scale, of time variations such as the learning and wear-out curves (Bathtub curve), climate change, and production volume non-linear effects.

6.4 Recommendations

The following recommendations based on the work may be made:

- Continue to utilize the Monte Carlo spill occurrence indicator model for new Arctic OCS scenarios to support BOEM needs, as it is currently the best predictive spill occurrence model available.
- Utilize the oil spill occurrence indicator model to generate additional model validation information, including direct application to existing non-Arctic scenarios, such as GOM and PAC projects, which have an offshore oil spill statistical history.
- Utilize the oil spill occurrence indicator model in a sensitivity mode to identify the importance of different Arctic effect variables introduced to provide a prioritized list of those items having the highest potential impact on Arctic oil spills.
- Generalize the model so that it can be run both in an adjusted expected value and a distributed value (Monte Carlo) form with the intent that expected value form can be utilized without the Monte Carlo add-in for preliminary estimates and sensitivity analyses, while for more comprehensive rigorous studies, the Monte Carlo version can be used.

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APPENDIX A

PROJECT DESCRIPTION [A.1]

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A.1 Sale 193 SEIS Exploration and Development Scenario (2014)

This is the description of a scenario for oil and natural gas exploration and development activities on the blocks leased in Sale 193. Scenarios are conceptual views of the future and represent possible, though not necessarily probable, sets of activities. The analysis for this scenario is unusual because Lease Sale 193 has already occurred. With this knowledge, BOEM has projected potential development based upon the post-sale analysis of tracts that received bids. Because the Chukchi Sea OCS is a frontier area with minimal exploration and no current development, the scenario is based on professional judgment and the characteristics of analogous onshore developments. This scenario is one possible outcome of a discovery of two prospects, geologic features with the potential for trapping and accumulating hydrocarbons.

There are four stages in this scenario:

Exploration;
Development;
Production; and
Decommissioning.

Three lease sales were held for the Chukchi Sea OCS prior to Lease Sale 193, and five exploration wells were drilled between 1989 and 1991. The wells tested five large prospects, but failed to find a commercial volume of oil. Operators either relinquished their leases or allowed them to expire. Using the past to predict future activity in the Chukchi Sea OCS, operators would likely purchase some leases, drill a few failed exploratory wells, and relinquish the leases. Several other Alaska OCS Planning Areas have followed this pattern. However, for the purpose of this analysis, it is assumed that exploration will be successful and two prospects will be developed and produced.

BOEM's 2011 Resource Assessment estimates that the Chukchi Sea OCS contains significant resources, concentrations of naturally-occurring hydrocarbons that can conceivably be discovered and recovered. The report estimates that the Chukchi Sea OCS contains mean undiscovered technically recoverable resources (UTRR) of 15.4 billion barrels of oil (Bbbl) and 76.8 trillion cubic feet of gas (Tcfg). These volumes could conceivably be discovered and produced with current industry technology. Resource estimates are based on seismic data, information obtained from the five exploratory wells, and extrapolation of geologic trends from existing onshore fields hundreds of miles away. The UTRRs do not take into consideration any limiting economic or logistic factors. BOEM also estimates undiscovered economically recoverable oil and gas resources (UERR) at different price levels. In BOEM's latest Resource Assessment, at a $110 per barrel oil price, 11.5 Bbbl of oil (75% of the UTRR) could be economic to develop, if discovered.

Even high quality seismic data can only indicate possible sites to explore. Seismic data must be interpreted by experienced geoscientists. As with all human interpretation, results are variable; even experienced interpreters can get different results from the same data set. The best seismic data and interpretation cannot indicate whether a reservoir will contain hydrocarbons, much less whether it will be economic to produce. Seismic data does not indicate rock properties that determine how fluids will flow or properties of the fluids themselves. Only well drilling and testing can provide this information.

A.2 Prospects

Development in a frontier area would likely start with a relatively large prospect to support the cost of initial infrastructure and to offer enough potential reward to make an operator decide to take the financial risk of development. Once this first anchor prospect is proven economic, a smaller nearby prospect can be added to capitalize on some of the existing infrastructure, such as pipelines, processing equipment, and shore-based plants.

In this scenario, a large prospect, Anchor A, and a smaller satellite prospect, A-2, are discovered, developed, and produced. Their combined potential oil and natural gas liquids are 4.3 Bbbl, 37% of the estimated UERR in the Chukchi Sea OCS at $110/barrel of oil (2011 Resource Assessment.) Producing this volume of oil and its associated natural gas will require eight platforms of a new Arctic-class design and drilling 589 wells (exploration, delineation, production, and service.) The time from exploration to final production is 74 years. Table A.1 shows the schedule for the scenario.

Table A.1: Exploration and Development Scenario Schedule For Anchor A and Satellite A-2

Activity	Beginning Year	Ending Year	Total Years
Perform Marine Seismic Surveys	*1*	*25*	*25*
Perform Geohazard Surveys	1	28	28
Perform Geotechnical Surveys	1	28	28
Install Platforms	10	30	21
Drill Exploration and Delineation Wells	3	22	20
Drill Production and Service Wells	10	34	25
Install Onshore Oil Pipeline	6	9	4
Install Onshore Gas Pipeline	27	31	4
Install Offshore Oil Pipelines	6	30	25
Install Offshore Gas Pipelines	27	50	24
Oil Production	10	53	44
Gas Production	31	74	44

A.3 Exploration Survey Activities

A.3.1 Marine Streamer 3D and 2D Seismic Surveys

Exploration begins by determining where to drill the first well. Seismic data and existing wellbore data are critical elements of an operator's drilling decisions. With only five exploratory wells drilled in the Chukchi Sea OCS, operators will perform seismic surveys prior to drilling exploratory wells.

A.3.2 High-Resolution Site-Clearance Surveys

A high-resolution seismic survey usually is conducted by the oil and gas industry to provide required information to federal agencies about the site of proposed exploration and development activities. High-resolution surveys: a) locate shallow hazards; b) obtain engineering data for placement of structures (e.g., proposed platform locations and pipeline routes); and c) detect geohazards, archaeological resources, and certain types of benthic communities.

A.4 Exploration and Delineation Drilling Activities

Operators will drill exploratory wells based on mapping of subsurface structures using 2D and 3D seismic data. Prior to drilling exploration wells, high-resolution site clearance seismic surveys and geotechnical studies will examine the proposed exploration drilling locations for geologic hazards, archeological features, and biological populations. Site clearance and other studies required for exploration will be conducted during the open water season before the drill rig is mobilized to the site.

Exploration drilling operations are likely to employ Mobile Offshore Drilling Units (MODUs) with icebreaker support vessels. Examples of MODUs include drillships, semisubmersibles, and jackup rigs. Drilling operations are expected to range between 30 and 90 days at different well sites, depending on the depth of the well, delays during drilling, and time needed for well logging and testing operations. Considering the relatively short open-water season in the Chukchi Sea OCS (July-November), we estimate two wells per drilling rig could be drilled, tested, and abandoned during a single open-water season. After a discovery is made by an exploratory well, MODUs will drill delineation wells to determine the areal extent of economic production. Operators need to verify that sufficient volumes are present to justify the expense of installing a platform and pipelines.

As many as 40 wells could be associated with exploring and delineating these prospects, including unsuccessful exploration wells on other prospects in the Chukchi Sea OCS, the drilling of which could be prompted by news of the first commercial discovery. Even successful exploration and delineation wells would likely be plugged and abandoned rather than converted to production wells because it would require several years before platforms and pipelines could be installed and the well produced. Leaving a well shut in for this length of time would be unlikely to be permitted by regulatory agencies.

A.5 Development Activities

Development activities include drilling production wells and installing platforms and subsea templates, pipelines, and shorebases. After an operator commits to develop a prospect, project designs will be evaluated and the operator will make development decisions based on, among other things, experience, expectations, and availability of equipment, personnel, and materiel. Another operator with a different set of experiences and expectations would make different decisions about how best to develop a prospect. The development plan is likely to undergo revision during the development phase as the operator incorporates lessons learned. Figure A.1 shows the schedule of platform installation and well drilling from the scenario.

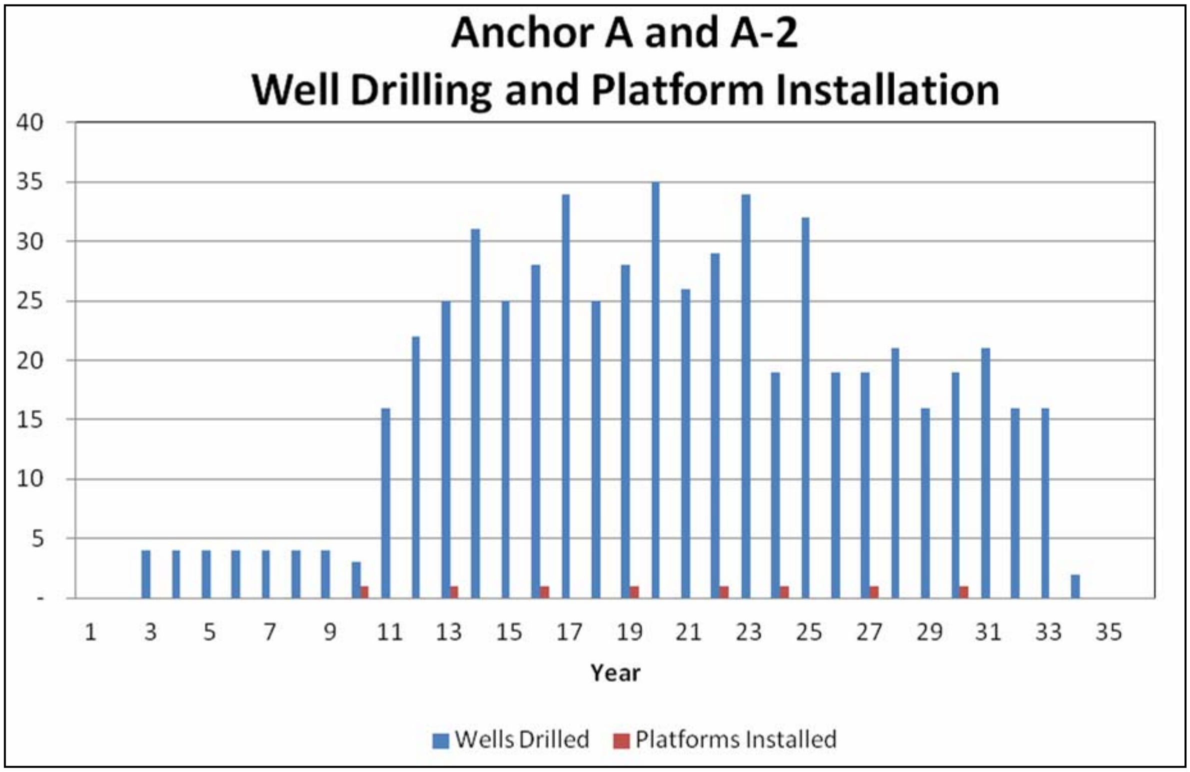


Figure A.1: Schedule of Platform Installation and Well Drilling

Water depth, sea conditions, and ice conditions are important factors in selecting a platform type. Large, bottom-founded platforms are likely to be used in the Chukchi Sea OCS, where water depths are mostly more than 100 ft. Conceptual designs have been proposed that are circular in cross-section, with wide bases constructed out of concrete. The platform could be constructed in several component sections, which would be transported to the site and then mated together. The seafloor is expected to be relatively firm in the assumed development area, so a prepared berm may not be required. The platform base is pinned to the seafloor and stabilized by its wide base, anchoring system, and ballast in cavities in the concrete structure to resist ice forces. Each platform will have two drilling rigs capable of year-round drilling; we estimate a maximum of eight wells per rig, or sixteen wells per platform per year. Each of the eight platforms in our scenario would house production and service (injection) wells, processing equipment, fuel and production storage capacity, and quarters for personnel. The first platform will be the hub, connecting pipelines from other platforms to the main pipelines to shore.

Ninety subsea production wells on fifteen subsea templates would be used in the development plan. MODUs would drill these subsea wells during the summer drilling season. With efficiencies gained by repeated operations, we assume that a single MODU could drill up to three subsea wells in a single season. Six subsea wells would produce to a template, which would be tied back to a platform by a subsea flowline. Subsea well templates would be located within about 2 miles of the host platforms, for a total of 30 miles of subsea flowlines to host platforms. Subsea equipment and pipelines could be installed below the seafloor surface for protection against possible deep-keeled ice masses.

The production slurry (oil, gas, and water) will be gathered on the platforms where gas and produced water will be separated and gas and water reinjected into the reservoir using service wells. During the later gas sales phase, water will continue to be reinjected. Disposal wells will handle waste water from the crew quarters on the platforms. Treated well cuttings and mud wastes for platform and subsea wells could be reinjected in disposal wells or barged to an onshore treatment and disposal facility located at the shore base.

A.6 Pipelines

Pipelines are the expected method of transporting both oil and gas to market. Subsea pipelines would connect the platforms in our scenario to the hub platform, and trunk pipelines would carry oil and gas from the hub platform to the shorebase. The shorebase would provide additional processing and connect to onshore oil and gas pipelines which would be laid 300 miles across the National Petroleum Reserve-Alaska (NPR-A) to Prudhoe Bay. At Prudhoe Bay, the oil pipeline would connect with the Trans-Alaska Pipeline System (TAPS) and the gas pipeline would connect with the gas pipeline that has been proposed to carry gas from Prudhoe Bay to south central Alaska.

In 1977, the 800-mile TAPS commenced transporting oil from Prudhoe Bay to the ice-free port of Valdez, in south central Alaska. According to Alyeska Pipeline Service Company, TAPS's operator, the pipeline capacity is currently 1.1 million barrels of oil per day; North Slope production is around 550,000 barrels per day in 2014. The scenario uses the current available capacity of 550,000 barrels per day as the maximum rate of oil production that could be accepted into TAPS from the Chukchi Sea OCS.

The gas produced from oil fields, such as Prudhoe Bay, is called associated gas because gas and produced water are byproducts of oil production, rather than being the primary product as from a gas field. There is currently no pipeline to get the gas produced from North Slope commercial oil fields to market, so most of it has been reinjected in the reservoirs to improve oil recovery. Approximately 35 trillion cubic feet (Tcfg) of natural gas could be produced from North Slope reservoirs if there were a way to transport it to market. In May 2014, the Governor of Alaska signed into law the All-Alaska Gas Line, a measure that could make Alaska a 25% shareholder in a project to bring natural gas from Prudhoe Bay to market. The plan is to build a gas processing plant on Alaska's North Slope, an 800-mile pipeline, and a Liquified Natural Gas plant in Nikiski, Alaska to process and ship gas to world markets. The estimated cost of the project is $45 to $65 billion; it could take 10 years to build. Other parties involved are the major North Slope oil producers and a Canadian pipeline company. Many pipeline projects have been proposed since Prudhoe Bay commenced commercial production in 1977, but no project has been developed. Another current proposal is for a smaller capacity line from Prudhoe Bay to provide natural gas for use by various communities in Alaska. Even the smaller pipeline from Prudhoe Bay would require years to permit, litigate, and build. If either pipeline were built, the 35 Tcfg from the North Slope fields would probably be transported first; gas from the Chukchi Sea OCS would have to wait for pipeline capacity to become available. Immediate gas sales without a reinjection phase would also result in faster decline of reservoir pressures, reducing the total volume of oil ultimately produced. Our scenario calls for gas production to be delayed until Year 31.

Installation of subsea flowlines from subsea templates to the hub platform and installation of the oil pipelines between platforms and from the central platform to shore will occur during summer open-water seasons. Pipeline installation operations would occur during the same timeframe as platform construction and installation. The offshore trunk pipelines run 160 miles between the central offshore platform and the shore. They will be trenched in the seafloor as a protective measure against damage by floating ice masses. At the coast, a new facility will be constructed to support the offshore operations and will serve as the first pump station. A likely location for the shore base would be between Icy Cape and Point Belcher.

The overland pipeline to TAPS through NPR-A will require coordination of different land managers and oil field owners along the route. In contrast to offshore pipelines, the new onshore pipeline will be installed during winter months. Various pipeline and communication lines will be installed on vertical supports above the tundra in a corridor stretching eastward 300 miles to connect to the North Slope TAPS gathering system. Pump stations may be required along the onshore corridor and are likely to be collocated with oil fields along the corridor. When the time comes for the gas to be sold, the entire offshore and onshore pipeline installation process must be repeated with gas pipelines running parallel to oil pipelines.

Delineation drilling would take three to four years after a discovery. It would be followed by permitting activities for the offshore project, submission of an approvable Development and Production Plan by the operator, and an agency Development EIS. When the project is approved, the design, fabrication, and installation of each platform could take another four years. Offshore and onshore pipeline permitting and construction would occur simultaneously with the offshore work. The scenario schedule requires the operator to commission subsequent platforms without an extended period of evaluation of the initial wells. Drilling the platform and subsea production wells would occur over a period of 24 years. A new shore base would be constructed to support offshore work and then serve as the connection point for the trunk pipelines from the hub platform and the pipeline across the NPR-A.

After the offshore project is constructed, operations will largely involve resupply of materials and personnel, inspection of various systems, and maintenance and repair. Maintenance and repair work will be required on the platforms, and processing equipment will be upgraded to remove bottlenecks in production systems. Well repair work will be required to keep both production and service wells operational. Pipelines will be inspected and cleaned regularly by internal devices (“pigs”). Crews will be rotated at regular intervals.

A.7 Transportation

Operations at remote locations in the Chukchi Sea OCS Lease Sale 193 area would require transportation of supplies and personnel by different means, depending on seasonal constraints and phase of the operations. The general assumptions discussed in this section can be integrated with the scenario schedule shown in Table IV.A-2a to determine the full extent of transportation activities associated with a large offshore development project.

During exploration seismic surveys, the vessels are largely self-contained. Therefore, helicopters would not be used for routine support of operations. Seismic operations would be in the summer/fall open-water season. We assume that the smaller support vessel would make occasional trips (once every 2 weeks) to refuel and resupply (probably operating out of Wainwright).

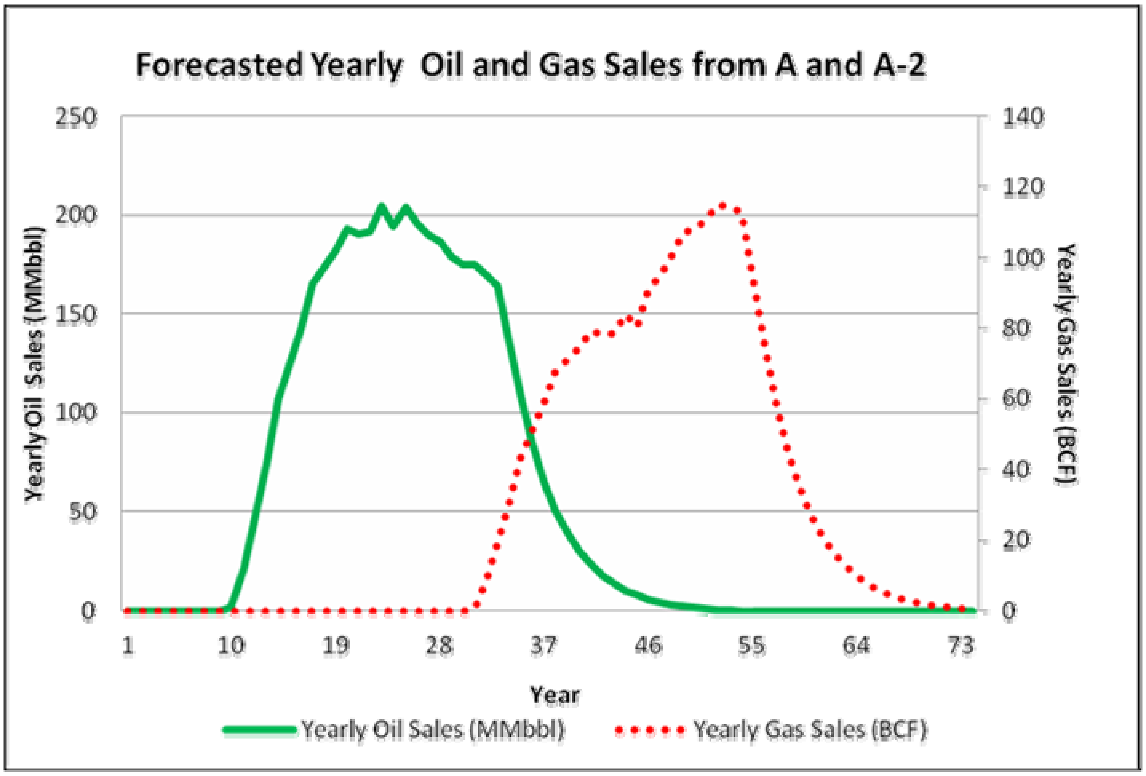
During exploration drilling, operations would be supported by both helicopters and supply vessels. Helicopters probably would fly from Wainwright at a frequency of one to three flights per day. Support-vessel traffic would be one to three trips per week, also out of Wainwright. For exploration-drilling operations that occur after a new shore base is established near Point Belcher, both helicopter and vessel traffic would be out of either Wainwright or the new shore base.

Construction of a new shore base would begin after a commercial discovery is made. Heavy equipment and materials would be moved to the coastal site using barges, aircraft, and perhaps winter ice roads. Transportation activities would be more frequent during the construction phase. During this construction phase, there could be one to two barge trips (probably from either West Dock or Nome) in the summer open-water season. Aircraft (C-130 Hercules or larger) trips could be up to five per day during peak periods. The overall level of transportation in and out of the shore base would drop considerably after construction is completed for both the shore base and offshore field area. During production operations, aircraft generally would be smaller, with less-frequent flights (2 per day). Ice-road traffic would be intermittent during the winter months.

Offshore construction (platform and pipeline installation) and development drilling operations would be supported by both helicopters and supply vessels from the new shore base. Helicopters probably would fly either from Wainwright or from the new shore base at a frequency of one to three flights per platform per day during development operations. Support-vessel traffic would be one to three trips per platform per week from either Wainwright or the new shore base. During normal production operations, the frequency of helicopter flights offshore would remain the same (1-3 per platform per day), but marine traffic would drop to about one trip every 1-2 weeks to each platform. Marine traffic would occur during the open-water season and possibly during periods of broken ice with ice-reinforced vessels. Assuming that barges will be used to transport drill cuttings and spent mud from subsea wells to an onshore disposal facility, we estimate one barge trip per subsea template (15 templates). This means that there could be two barge trips (during summer) to the new onshore facility each year for a period of twelve years.

A.8 Production Activities

Oil production will commence with the drilling of the first platform production well and ramp up as more wells are drilled. When the oil resources are depleted, oil production and gas injection (service) wells would be converted to gas production. Service wells will continue to reinject produced water throughout oil and gas sales operations. Figure A.2 shows the forecasted yearly oil and gas sales.



Notes: MMbbl- Million barrels BCF – Billion Cubic Feet

Figure A.2: Forecasted Yearly Oil and Gas Sales from A and A-2

A.8.1 Timing

Three factors were evaluated for possible influence on the length of time needed to complete the development and production phases of this scenario.

Gas sales will be delayed until oil production is nearly complete.
Available TAPS capacity is limited.
It will take twenty years to install all the platforms. This controls how quickly wells can be drilled.

The delay of gas sales strongly influences the length of time for the production phase, but the current lack of a pipeline from the North Slope to south central Alaska and the need to maximize oil production make this the most likely production strategy.

The issue of available TAPS capacity has also been discussed. This limit was used as a check to ascertain that adding production from the satellite prospect, A-2 would not exceed available capacity. Pipeline capacity limits created no delay in bringing Prospect A-2 on production. The real driver of the timeline is the time needed to install platforms and drill their associated wells. The platform design used in this scenario has never been built. Each platform would be designed specifically for its proposed location, built in a shipyard (often in Asia), and towed into place. Construction time is estimated to be four years. The design of each new platform would likely be modified based on the operation of previous platforms. There is no allowance in the schedule for redesign, construction delays, or installation issues. Platform installation occurs every third year in the scenario. Each platform is installed, commissioned, and producing in its first year. There are no regulatory or legal delays factored into the schedule.

Table A.2 summarizes the development scenarios key components.

Table A.2: Scenario Results for Development of Anchor A and Satellite A-2 Oil Prospects

Element	Range	Comment
Marine Seismic Surveys	4-12	Will vary based on number of operators
Geohazard Surveys	10-16	Will vary based on number of operators
Geotechnical Surveys	10-16	Will vary based on number of operators
Platforms	8	
Exploration and Delineation Wells	30-40	Includes dry holes and additional unsuccessful wells on other Chukchi Sea OCS prospects drilled after a success
Production Wells	400-457	457 required to produce all the recoverable oil
Service Wells	80-92	20% of production wells
Onshore Oil Pipeline (miles)	300-320	Longer distance may be required for rerouting
Onshore Gas Pipeline (miles)	300-320	Longer distance may be required for rerouting
Offshore Oil Pipeline (miles)	190-210	Miles will vary based on location of actual prospects
Offshore Gas Pipeline (miles)	190-210	Miles will vary based on location of actual prospects
Total Oil Production (Bbbl)	4.0-4.3	
Total Gas Production (Tcfg)	2.0-2.2	
Peak Oil Rate (bbl/day)	558,702	
Peak Gas Rate (MCF/day)	314,618	
New Pipelines to Shore	2	1 oil trunkline, followed by 1 gas trunkline in same corridor near Wainwright
New Shore Base	1	Near Wainwright
New processing facility	1	At new shorebase
New waste facility	1	At new shorebase
Drilling fluids from exploration and delineation wells (tons)	2850-3800	475 tons/well, with 80% recycled drilling fluid from intermediate and production strings
Rock cuttings discharge for exploration and delineation wells (tons)	18,000 – 24,000	600 tons/well
Discharges for Service and Production Wells (tons)	0	Drilling fluid and rock cuttings will be disposed of in service wells or barged to shore for disposal.
Flights per week during production phase	56-168	1 to 3 flights per platform per day
Boat Trips per week during production phase	8-16	1 to 2 trips per platform per week
Years of Activity	70-74	Final gas production may be truncated for economic reasons

A.9 Abandonment/Decommissioning Activities

After both oil and gas resources are depleted and income from production no longer pays operating expenses, the operator will begin to shut down the facilities. In a typical situation, wells will be permanently plugged with cement and wellhead equipment removed. Processing modules will be moved off the platforms. Pipelines will be decommissioned by cleaning the pipeline, plugging both ends, and leaving it in place buried in the seabed. The overland oil and gas pipelines are likely to be used by other fields in the NPR-A and would remain in operation. Lastly, the platform will be disassembled and removed from the area and the seafloor site will be restored to some practicable, predevelopment condition. Post abandonment surveys would be required to confirm that no debris remains following abandonment and pipelines were abandoned properly.

A.R Reference

A.1 BOEM, Email of June 25, 2014.